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-2007-0002

<u>PREHEARING BRIEF OF UNION ELECTRIC COMPANY D/B/A AMERENUE</u>

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<u>Statement of the Case</u>[1]

This case marks AmerenUE's first request for an increase in its rates since 1987. While any request for a rate increase is unpopular, a rate increase has become necessary to address, among other things, a number of challenges facing the Company. Among those challenges are (1) sharply increasing fuel and fuel transportation costs; (2) rising operating costs, including medical and benefit costs for employees and retirees; (3) substantial increases in the cost of equipment and materials; (4) the need to continue to make substantial infrastructure investments to meet growing customer demands and growing customer expectations for reliable service; (5) a changing and volatile energy market place; (6) rising interest rates; (7) the difficulty of maintaining and improving the performance of aging power plants and of meeting the operational challenges posed by increasing environmental requirements; (8) the desire to add renewable sources of generation; (9) investors' higher return expectations due to increasing operating risks; and (10) political and regulatory uncertainty and its effect on investor expectations, credit quality, and the availability of the capital needed to support an electric utility business today.

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[1] In this Prehearing Brief, the Company has endeavored to provide the Commission with a "roadmap" of the evidence we expect regarding each issue which we believe remains contested in the case. Consequently, the Brief may appear somewhat lengthy. However, the Brief is structured in such a way that the Commission can read the roughly four page Statement of the Case appearing at the beginning and then, as each issue comes up at the hearing, can read the particular section related to that particular issue. We believe this will facilitate the Commissioners' participation in the hearings and the presentation of the case by the parties.

Even if the Company's entire rate increase request were granted, the Company's rates would remain 26% below the U.S. average, at least 7% below the average of other Midwestern states, and would remain lower than the average rates of the other Missouri investor-owned utilities (*See* **Exhibit 1** hereto). To put these numbers in perspective, consider what has happened to the cost of just about everything else in the 20 years since the Company last requested a rate increase. As shown on **Exhibit 2** hereto, from1990-2005, virtually everything else has gone up from 45% to 133%, while AmerenUE's rates have gone down 13%. This means that if AmerenUE's entire rate increase request were granted, AmerenUE's rates would have gone up only slightly in the past 20 years, even though everything else will have gone up substantially.

Others, principally the Staff, the State of Missouri, represented by the Attorney General's Office, and the Office of the Public Counsel,[2] advocate rate decreases. Any such rate decrease, or the failure to award a fair rate increase, would strike at the heart of the Company's ability to meet the challenges noted above and would without question impair its ability to do so.

Viewed objectively, and consistent with the Commission's duty as adjudicators to follow the law, the evidence in this case will show that AmerenUE needs a sizeable rate increase in order to pay its cost of providing service to customers, including earning a fair and reasonable return on the large investment the Company's shareholders have made, and to maintain the financial strength necessary to continue to invest in system infrastructure. In other words, a rate increase is necessary to reflect just and reasonable rates for AmerenUE's customers.

[2] Public Counsel not only recommends a rate decrease, but has obviously pre-judged the Company's request without regard to its merits, as evidenced by its formal and informal advocacy of outright dismissal of the case, including in the press. The Commission should consider the credibility of those who advocate rate decreases and dismissals without regard to the merits when considering the evidence and arguments made by those parties.

Those who dispute the need for a sizeable rate increase do so by taking positions on issues that simply cannot be sustained as a matter of law, or fact. The most noteworthy example of their willingness to stretch both the facts and the law beyond reasonable and lawful boundaries is their attempt to reach non-jurisdictional investments, namely earnings belonging to the shareholders of Electric Energy, Inc. (EEInc.). These parties urge this Commission to disregard the law and to impute revenues to AmerenUE on the grounds that EEInc. directors who are, in part, elected as a result of AmerenUE voting its shares, should have breached their fiduciary duties to shareholders by continuing to force EEInc. to contract with AmerenUE to sell power at cost, despite the fact that EEInc. now has the ability to sell its power at market-based rates in the newly emerged transparent wholesale power markets, such as the markets created by the Midwest Independent Transmission System Operator, Inc. (MISO) in 2005. At bottom, these parties advocate unlawful actions on the part of this Commission in seeking to convince the Commission to do indirectly what the Commission cannot lawfully do directly. In doing so, these parties also ask the Commission to impute unlawful acts by those having fiduciary duties to a corporation outside the Commission's jurisdiction. This issue is so important that we address it first, below.

Other key contested issues that have a large effect on the Company's revenue requirement arise from the unreasonably low, out-of-the mainstream recommendations of the Staff, OPC, and the State with regard to the return on equity (ROE) that is appropriate for the Company, the argument that depreciation rates should be set based upon the complete fiction that the Company's generating plants will last forever, and attempts to write-down (without any meaningful engineering or cost analyses) the value of necessary generating assets acquired by the Company as fully contemplated by the Commission's order in the Company's last rate proceeding (Case No. EC-2002-1), for which the Company paid net book value – no more and no less.

The Commission's task in this case is to recognize that ratemaking involves a determination of the true costs, investments, and related returns necessary to ensure that a utility can deliver safe and reliable service over the long term to its customers, but ratemaking is also more than that. Ratemaking is also an exercise in using the Commission's collective common sense and judgment to arrive at a fair result, it is an exercise in following the law within which we all must operate, and in this case in particular it is an exercise in not getting lost in competing testimony and arguments from attorneys, engineers, accountants, and consultants. The Company believes that if the Commission approaches this exercise with those principles firmly in mind, it will arrive at a decision that results in fair, just, and reasonable rates.

Revenue Requirement Issues

1. Is it lawful and proper for the Commission to impute to AmerenUE's revenue requirement the net effect on AmerenUE's variable production costs of the unavailability of power from EEInc?[3]

It is the Company's position that it is not lawful or proper to impute any sums to AmerenUE's revenue requirement relating to EEInc. The legal and policy issues inherent in this issue are of paramount importance in this case. Consequently, we address this issue first and in a comprehensive manner, below.

A. FACTUAL BACKGROUND – EEINC.

The dispute between the other parties and the Company concerning their proposed EEInc. adjustment really does not rest on any dispute over the material facts, but rather the other parties'

[3] As indicated in the Proposed List of Issues, Order of Witnesses and Order of Cross-Examination pleading filed by Staff, all parties did not agree on whether all issues listed in that pleading are in fact issues or whether issues were properly characterized. Consequently, the Company's statement of some of the issues in this Prehearing Brief will differ at times from the statement of those issues in Staff's pleading.

characterization of the facts and the unprecedented legal consequences they draw from those facts. Though the national-defense origins and purpose of EEInc. did result in some distinctive features in the structure and operation of that company, the material facts are straightforward.

i. EEInc. is an Illinois corporation formed in 1950 by five independent Midwest utilities, including Union Electric, as part of a post-World War II national defense initiative, to provide electric power for a new Federal uranium enrichment facility at Paducah, Kentucky.

EEInc. was a groundbreaking step, taken in 1950, by which private industry cooperated with the Federal Government in an important national defense initiative triggered by the beginning of the Cold War, and the dawn of the nuclear age. The United States Government (now acting through the Department of Energy) needed a reliable source of electric power for the heavy demands of its new uranium enrichment plant at Paducah, Kentucky. Through "enrichment," the concentration of U-235 in the uranium is increased, making uranium useful for producing the energy needed for nuclear weapons. The purpose of EEInc. was to provide the electrical power for running the Paducah facility.[4]

EEInc. was formed by Union Electric Company (UE), Central Illinois Public Service Company, Illinois Power Company, Kentucky Utilities Company, and Middle South Utilities, Inc., called the "Sponsoring Companies." Each purchased stock in the newly formed company.[5] EEInc. built its power plant to serve Paducah's operations nine miles away, in Joppa, Illinois. It is easy to forget now, 50 years later, that it was not a foregone conclusion back then that the private sector could step up to the plate in this way. Many thought that only the Government

[4] Rebuttal Testimony of David A. Svanda at 5:7-14 (Svanda Rebuttal); Direct Testimony of Michael L. Moehn at 11:1-4 (Moehn Direct); Surrebuttal of Michael L. Moehn at 1:21-2:1, 5:1-17-21 (Moehn Surrebuttal); Direct Testimony of Greg G. Meyer at 6:8-11 (Meyer Direct); Direct Testimony of Michael L. Brosch at 18:20-23 (Brosch Direct).

[5] Svanda Rebuttal at 5:15-21; Meyer Direct at 6:11-17.

could command the resources needed for such a massive undertaking. The Sponsoring Companies of EEInc. proved those doubters wrong.

But this enterprise was a novel and risky move for these private companies. EEInc. financed the Joppa Plant with a capital structure of approximately 96% debt and 4% equity, for the purpose of minimizing income taxes and income.[6] Certainly more debt was involved in capitalizing EEInc. than the Security and Exchange Commission (SEC) would normally accept in the financing of public utilities. The SEC approved this unconventional capital structure on the strength of the power contracts between EEInc. and the Government and the Sponsoring Companies, and, as the SEC put it, due to "the importance of the proposed generating facilities to the national defense."[7]

EEInc. is a separate, for-profit corporation with legal rights and duties that are completely distinct from those of AmerenUE.

ii. AmerenUE purchased EEInc.'s stock with shareholder funds, and EEInc. has never been in AmerenUE's rate base nor considered as an above-the-line asset for setting AmerenUE's rates. The risk associated with this investment has, accordingly, always been borne by AmerenUE's shareholders, not its ratepayers.

AmerenUE's equity investment in the stock of EEInc. was made as a below-the-line investment with shareholder money, not with ratepayer money. The significance of this investment being below-the-line lies in the fact that for ratemaking purposes, below-the-line investments are excluded from any rate base, cost of capital, or other calculations relating to the utility's cost to serve its utility customers.[8] Consequently, ratepayers do not bear any responsibility for potential losses on these non-regulated investments. It follows therefore, that

[6] Moehn Surrebuttal at 5:22-26.
[7] 32 SEC 498 (1951). *See also* Moehn Surrebuttal at 5:22-26.
[8] Rebuttal Testimony of Michael L. Moehn at 3:2-7 (Moehn Rebuttal); Direct Testimony of Kevin C. Higgins at 10: 13-14 (Higgins Direct); Deposition of Robert E. Schallenberg at 69:5-8, 13-19 (Feb. 21, 2007) (Schallenberg Dep.).

any risk associated with this investment, had it been related to the construction of the Joppa Plant, or related to the ongoing operations of EEInc., falls clearly on AmerenUE's shareholders and not on AmerenUE's ratepayers. AmerenUE's ratepayers are not in any sense "owners" of EEInc. or the Joppa Plant.[9]

Today, AmerenUE's shareholders own 40% of the outstanding shares of EEInc. stock.[10] Dividends paid from the earnings of EEInc. flow to the shareholders of the Sponsoring Companies, as do any gains and/or losses associated with any investments made by EEInc. Several employees of Ameren Corporation affiliates sit on EEInc.'s Board of Directors.

iii. From 1951 through 2005, the purchase power agreements between the Government, the Sponsoring Companies and EEInc. were cost-based, firm power contracts (as was common before transparent wholesale power markets had emerged) that included both capacity and energy charges that covered all the costs of generating power from the Joppa Plant. Through its purchases of power from EEInc., AmerenUE has actually paid for a percentage of EEInc.'s costs far smaller than its 40% share of EEInc.'s stock.

The Government and the Sponsoring Companies were required, through separate purchase power agreements, to buy 100% of EEInc.'s power. The initial Power Contract, No. AT-(40-1)-1312, was signed in 1951 and has been modified and revised a number of times over the past 50 years, with the most significant revision occurring in 1987 with Modification No. 12, which was entered into September 2, 1987, by EEInc. and the Department of Energy (DOE), and which expired by its express terms on December 31, 2005. EEInc. signed a separate Power

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[9] Schallenberg Dep. 69:20-22. EEInc.'s principal asset is the coal-fired Joppa generating station. EEInc. also owns four subsidiaries: Joppa & Eastern Railroad Company (short line railroad); Massac Enterprises, LLC (enterprise zone retailer); Met-South, Inc. (fly ash seller); and Midwest Electric Power, Inc. (MEPI) (combustion turbine generating facility). Moehn Surrebuttal at 6: 4-8.

[10] In 1950, in Case No. 12,064, UE sought and received authority from the Missouri Public Service Commission (Commission) to acquire its initial shares of stock in EEInc. In 1952, in Case No. 12,463, UE sought and received authority to purchase additional shares of EEInc. stock. Moehn Direct at 11: 12-15.

Supply Agreement (PSA) with the Sponsoring Companies in 1987 that tracked Modification 12. It also expired by its express terms on December 31, 2005.[11]

The 1987 PSA between the Sponsoring Companies and EEInc. was a contract that set the price of the energy and capacity to be sold to the Sponsoring Companies according to a cost-based formula, when no wholesale market for power existed that could be used to set a market-based rate. As was common, both capacity and energy charges were included in the calculation of the price in order to recover all the costs of producing that power. Included in the fixed costs covered by these charges was a 15 % return on equity (ROE).[12]

Under the terms of the PSA, the Sponsoring Companies had an obligation to buy the power from EEInc. that was not purchased by the Government. Not surprisingly, given that the purpose of the whole enterprise was to provide electricity to meet the large power demands of the Government's Paducah facility, the Government took the lion's share of EEInc.'s power. From 1954-2005, the Government and the other Sponsoring Companies (other than AmerenUE) took roughly 85% of the output of the Joppa Plant while paying for a similar level (84%) of EEInc.'s total sales in dollars associated with producing that output. As a consequence, AmerenUE power purchases covered only 16% of EEInc.'s total Joppa Plant costs while AmerenUE received approximately 15% of the total MWhs generated by the Joppa Plant over this same period.[13] So even though AmerenUE owns 40% of EEInc.'s stock, its purchases of EEInc. power over the years actually covered a much smaller percentage of EEInc.'s costs.

Thus it is generally of no significance to say that "[t]he customers of EEInc. fully reimbursed all of the costs of operating, maintaining, insuring and improving the Joppa Plant for

[11] Moehn Surrebuttal at 6:21-13, 21-26.
[12] Svanda Rebuttal at 6:21-23; Moehn Surrebuttal at 6: 13-16.
[13] Moehn Rebuttal 8: 4-9 and Schedule MLM-1 (summarizing EEInc. sales).

the initial decades of its existence."[14] Those customers only "reimbursed" EEInc. for its costs through the power that they purchased. (This is hardly unique. A buyer of any commodity "reimburses" the seller for the costs of producing that commodity.) AmerenUE's share of those purchases was small, and AmerenUE's purchases were smallest during the initial decades of EEInc.'s existence,[15] precisely when the costs of EEInc.'s operation were the highest.

The costs paid by AmerenUE under the prescribed formulas set out in the PSA were included in the Company's cost of service as a component of fuel and purchased power expenses. In every year, AmerenUE received a level of power, be it capacity and/or energy, from EEInc. to serve its ratepayers that was commensurate with the charges included in AmerenUE's cost of service.

Moreover, these power purchases from EEInc. were a great deal for AmerenUE's ratepayers. Over the period from 1954-2005, the average annual cost of EEInc.'s power to AmerenUE was $14.19/MWh, including costs for capacity and energy.[16] Not surprisingly, no one has ever suggested that any aspect of these power purchases from EEInc. was imprudent, or that including the charges for that power in AmerenUE's cost of service was in any other way improper. Over the roughly 50 years that AmerenUE had purchase power agreements with EEInc., none of the other parties in this proceeding ever questioned the terms, price, or structure of the agreements under which AmerenUE obtained power that it used to serve ratepayers.

iv. Consistent with its status as a shareholder investment, the relationship between AmerenUE and EEInc. did not impose any risk or burden on AmerenUE's ratepayers.

Throughout the history of EEInc., AmerenUE has always behaved consistently with the principle that the investment in EEInc. was an undertaking of AmerenUE's shareholders, and

[14] Surrebuttal Testimony of Michael L Brosch at 33: 26-28.
[15] Schedule MLM-1, page 3 of 4.
[16] Moehn Rebuttal 8: 14-16.

that the risks of owning 40% of EEInc.'s stock, and of any other commitment AmerenUE made to EEInc., was borne by AmerenUE's shareholders, not its ratepayers. Of course, now with the benefit of hindsight, we know that the Joppa Plant never had serious operational problems, costs did not skyrocket making the PSA uneconomic, and none of a myriad of other risks ever materialized. Power from the Joppa Plant turned out to be relatively low-cost, and power purchases made by the Federal Government provided revenues that covered most of the major costs of the Joppa Plant and provided a return on the shareholders' investment. Nor was there any proceeding before the Commission in which stating this principle was relevant. So, besides the fact that the investment in EEInc. was always treated as a below-the-line matter, there was no need over the years to make a record before the Commission that if any catastrophe happened to EEInc., AmerenUE's shareholders would have had to absorb the financial consequences.

Nevertheless, the other parties are championing this EEInc. adjustment based, as we will discuss in detail below, on their notion that AmerenUE's ratepayers bore some risk related to EEInc. It is only basic fairness that they have to offer affirmative evidence that this was the case, not that the Company now has to prove a negative (that the Company would not have sought to recover the cost of an EEInc. catastrophe in retail rates). Cutting through the fog of their vague claims, it becomes apparent that the other parties have not and cannot offer such evidence.

Notwithstanding the other parties' characterizations,[17] the PSA's pricing mechanism, which included an ROE cost component, did not force AmerenUE's ratepayers to "absorb" any risk. The uncontroverted evidence is that ROE is a fixed cost traditionally included in a capacity charge, as it was in the PSA's pricing formula. Moreover, AmerenUE's ratepayers got something of value, low-cost electricity, in return for AmerenUE's purchase power payments to EEInc. Ratepayers did not in any way invest in EEInc. or pay for something they did not

[17] *See, e.g.,* Brosch Direct at 20: 1-2.

receive. AmerenUE's retail customers played no more of a role in "assuring the financial viability"[18] of the Joppa Plant than do customers of any business play a role in assuring the viability of that business by purchasing the goods and services of that business. EEInc. sold a product; AmerenUE purchased that product to serve its ratepayers; and the cost of that product was properly included in AmerenUE's cost of service to serve those ratepayers.

Similarly, the other parties contend that the PSA provision in which the Sponsoring Companies agreed to purchase EEInc. power not bought by the Government shifted risk to ratepayers. In addition, they point to the Sponsoring Companies' "guarantee" of a small 1977 bond issued to finance pollution control equipment as another example of such risk-shifting.[19] The small bond was retired in due course, and the guarantee was never exercised. Yet whatever minor risk this guarantee may have posed (and it posed a risk to shareholders not ratepayers) never materialized, and so these arrangements by themselves do not prove that AmerenUE – contrary to the Company's consistent practice – would have turned to ratepayers for payment if the worst had happened. To the contrary, these financial "backstops" supported lower cost financing for EEInc., resulting in the benefit of lower cost power for ratepayers.[20]

Further contradicting any suggestion that AmerenUE would have acted inconsistently with the below-the-line character of the EEInc. investment is the fact that when EEInc.'s subsidiaries did suffer losses, as was the case with EEInc.'s subsidiary MEPI's operating losses, and with the write-off of approximately $1.7 million related to an abandoned project to construct a coal transfer terminal, those losses were absorbed by EEInc.'s shareholders, and not passed on to any of the Sponsoring Companies' ratepayers.[21]

[18] Higgins Direct at 10: 15-16.
[19] Higgins Direct at 12:4 – 13:21.
[20] Moehn Rebuttal at 9: 7:21.
[21] Moehn Rebuttal 6: 4-20.

Most strikingly, the position of the other parties concerning these risks supposedly borne by ratepayers assumes away the role of this Commission and the regulatory regime in which AmerenUE must operate. If, as a result of a contractual commitment in the PSA, AmerenUE had to buy excessive power from EEInc. that was priced far above power available from other sources, it is unimaginable that other parties would not object, or that this Commission would allow, such imprudent costs to be recovered in AmerenUE's cost of service. Indeed, those who incorrectly assume ratepayers bore the risk of EEInc. losses have admitted that is not the case. For example, Staff witness Greg Meyer admitted that if power from EEInc. became uneconomic, it would be imprudent for AmerenUE not to buy more economic power.[22]

Finally, the other parties try to bootstrap some notion of ratepayers bearing risk by speaking of EEInc. as somehow being "jurisdictional" due to the PSA,[23] or claiming that there are "costs related to AmerenUE's share, 40%, of EEInc.'s Joppa unit" that were treated as an above-the-line expense.[24] But AmerenUE never incurred 40% of the costs of the Joppa Plant. It paid for power that covered 16% of Joppa's costs.[25] If the 40% interest in EEInc. really had the significance that these other parties claim, AmerenUE's Missouri cost of service would have included roughly $800 million to pay for the Joppa capacity charges, irrespective of the electricity ratepayers received in return, as opposed to the roughly $350 million included in that cost of service for which those ratepayers actually received electricity.[26] Indeed, Schedule MLM-2 to Mr. Moehn's Rebuttal Testimony strikingly illustrates how different (and more costly) AmerenUE's relationship to EEInc. would have been if that relationship was treated like

[22] Meyer Deposition, p. 44, l. 12-22.
[23] Rebuttal Testimony of Michael L. Brosch at 9: 17-20 (Brosch Rebuttal).
[24] Surrebuttal Testimony of Robert E. Schallenberg at 7:18-19 (Schallenberg Surrebuttal).
[25] Moehn Surrebuttal at 17: 16-18.
[26] Schedule MLM-3.

the above-the-line "regulatory asset" proposed by the other parties as opposed to the straightforward, purchase power contractual relationship it actually was.

v. Under its express terms, the PSA expired at the end of 2005; EEInc. secured approval from the Federal Energy Commission (FERC) to sell power at market price in the newly emerged wholesale market; and EEInc.'s Board concluded it was not in EEInc.'s best interest to sell its power at a below-market price. As a result, the EEInc. Board declined to extend the expired, cost-based PSA.

When EEInc. was established, power transactions in the utility industry were based solely on cost-based tariffs and contracts. A transparent market for wholesale power that would develop some 50 years later, where suppliers and buyers are free to engage in a competitive generation market and power is priced at market rates, was not foreseen at the time. Even the PSA, which began in 1987, significantly pre-dated critical legislative and regulatory developments that facilitated the formation of competitive wholesale power markets, such as the Energy Policy Act of 1992 (which gave FERC expanded authority to order the provision of transmission access) and FERC's Order 888, issued in 1996, which required all FERC-jurisdictional utilities to provide open transmission access and to functionally separate their transmission operations from their wholesale power sales activities. An organized regional wholesale power market administered by the MISO did not emerge until even later, after MISO began offering transmission service under its own tariff on February 1, 2002, and offered a formal spot market for wholesale power (the "Day Two Market") in April 2005.[27]

However, by the time the PSA expired on December 21, 2005, those dramatic changes in the wholesale power world had occurred. In December 2005, EEInc. received FERC approval to

[27] Moehn Surrebuttal at 21: 11-16 (quoting Dr. Michael Proctor to the effect that a transparent wholesale market would come into being when the "day-two markets" begin).

sell power at market-based prices.[28] EEInc.'s directors then properly acted in EEInc.'s best interests by choosing to sell EEInc.'s power in that newly created market now available to it.

B. THE COMMISSION CANNOT LAWFULLY IMPUTE TO AMERENUE'S REVENUE REQUIREMENT THE NET EFFECT ON AMERENUE'S VARIABLE PRODUCTION COSTS OF THE UNAVAILABILITY OF POWER FROM EEINC.

i. The Proposed EEInc. Adjustment Cannot Be Ordered When AmerenUE Could Not Legally Compel EEInc. to Extend the PSA or Otherwise Sell It Power on a Cost Basis.

a. The testimony of the witnesses supporting the EEInc. adjustment is based on legal opinions they are not competent to offer and, as a result, that cannot lawfully serve as the basis for the Commission ordering such an adjustment.

All the witnesses proposing an adjustment to AmerenUE's revenue requirement due to the expiration of the EEInc. PSA do so on the ground that the expiration of that contract was a manifestation of imprudence on the part of the Company, or was inequitable, and that the Company is responsible. At the heart of these claims is the incorrect and unsupported notion that the expiration of the PSA was the result of a decision *by AmerenUE,* because, in the opinion of these witnesses, the Company in some way had a legal right or power to compel EEInc. to sell its power at a below market price to AmerenUE.[29] As Prof. Robert Downs notes:

> There is no way to understand the "right" of one corporation to compel another to do its bidding (and against that other corporation's obvious best interest) other than as a legal right. If the law does not give AmerenUE the right these witnesses claim (and correspondingly impose an obligation on EEInc.), nothing else does.[30]

[28] The Commission and the Missouri Industrial Energy Consumers filed notices of intervention, but did not file comments or protests to the application. The OPC filed a motion to intervene and protest. All of OPC's arguments were rejected by FERC.

[29] *See e.g.,* Schallenberg Surrebuttal at 9: 5-8,11 ("AmerenUE voted to approve a power supply agreement that sold its share of the energy from the Joppa Plant to an affiliate … at a rate higher than the cost based terms[of the PSA]…. The decision that created this issue was made by AmerenUE not EEInc."); Higgins Direct at 14: 22-23 ("AmerenUE has made a corporate decision to forego the opportunity to extend that [PSA].")

[30] Surrebuttal Testimony of Professor Robert C. Downs at 2: 4-8 (Downs Surrebuttal).

Yet not one of these witnesses is a lawyer or qualified to offer a legal opinion in these proceedings.[31] The fact that these witnesses do not have the qualifications to give them the legal competence to offer this kind of evidence to this Commission is not simply a matter of legal technicalities, but of basic fairness and reliability. Their testimony suffers from the fundamental practical handicap that, with respect to their opinions about what AmerenUE could do to legally compel a separate corporation to act against its interests, they simply do not know what they are talking about.

The deposition of Staff witness Robert Schallenberg illustrates this point. Mr. Schallenberg does not know whether EEInc. owns the Joppa Plant power.[32] Mr. Schallenberg does not know whether, as a matter of law, shareholders are entitled to manage a company in which they own stock.[33] (Yet he contends that it is by virtue of their stock ownership that the Sponsoring Companies "control" EEInc. and can compel it to sell Joppa power at below-market rates.)[34] Mr. Schallenberg does not know whether directors, shareholders, employees, managers, and officers have distinct obligations and duties under the law.[35] Likewise he does not know if directors have legal duties and obligations that arise from sources of law outside the corporation and its bylaws.[36] He does not know if directors have fiduciary duties that are defined by law outside of the documents that establish a corporation and govern its operations.[37] Logically, he

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[31] *See, e.g.,* Schallenberg Dep. 8: 17-19 ("I have never represented that I am an attorney or am qualified to provide legal opinions."); Brosch Direct 24: 21-22 ("I am not an attorney and cannot offer any legal opinion regarding the obligations of management."); Deposition of Michael L. Brosch at 6: 5-10 (Jan. 11, 2007) ("Q. … And so you are not qualified to undertake any kind of legal analysis, correct? A. That's true. Q. And you're also not qualified to offer any legal opinions, correct? A. That is correct.") (Brosch Dep.); Higgins Direct at 10: 4-5 (stating that "I am not an attorney and will not attempt to draw conclusions of law," though that's precisely what he went on to do).
[32] Schallenberg Dep. at 23: 15-18.
[33] Schallenberg Dep. at 24: 4-7.
[34] Schallenberg Surrebuttal at 9: 11-15.
[35] Schallenberg Dep. at 25: 10-13.
[36] Schallenberg Dep. at 27: 7-10.
[37] Schallenberg Dep. at 29: 20-24. *See also* Brosch Dep. at 38: 5-6 ("I don't know what duties and obligations there are from a legal perspective ….").

does not know whether bylaws or other corporate documents can change those legal duties.[38] Mr. Schallenberg does not know whether directors are entitled to defer to the wishes of control shareholders to transfer corporate assets to those shareholders at below fair market value.[39] Nevertheless, without this most basic knowledge of the law regarding corporate governance, Mr. Schallenberg offers an opinion that urges this Commission to lower AmerenUE's revenue requirement by a significant amount because, Mr. Schallenberg claims, AmerenUE was imprudent since it did not compel EEInc. to sell Joppa power to it at its preferred price by directing "its" directors on EEInc.'s Board "to vote that way."[40]

Compounding these witnesses' ignorance of the basic legal rules that govern the actions of corporate directors is their utter disregard for the consequences of flaunting these rules. Their arguments for this adjustment that imply that AmerenUE is motivated solely by a crass profit motive or otherwise has ignored the public interest is not only unfair, but betrays their own narrow, self-interested perspective. Put charitably, it is as if they have not read the newspapers for the last five years. The Enron and similar scandals revealed a shocking level of corporate malfeasance, and has properly provoked a renewed vigor in enforcing, and in punishing violations of, the very rules governing corporate directors and officers of which these witnesses from the other parties are so ignorant. In our post-Enron environment, directors who blithely ignore their responsibilities to the corporations on whose boards they sit risk jail terms and/or significant fines, or, at a minimum, lawsuits from shareholders to whom they owe their duties.

Contrasted with these witnesses' lack of competence to offer the legal opinions on which their EEInc. adjustment rests is the Company's witness on these matters, Prof. Robert C. Downs of the UMKC School of Law. Both as a practicing lawyer and as a scholar, Prof. Downs has

[38] Schallenberg Dep. at 27: 12-14.
[39] Schallenberg Dep. at 27: 15-19.
[40] Schallenberg Dep. at 24: 17-20.

committed his professional life of over 30 years to corporate law. He advises boards of directors on the very legal duties that are at issue here. He has been an expert witness on corporate governance in both state and federal courts.[41] Prof. Downs offers the only competent, credible evidence concerning the key corporate governance principles that must determine the resolution of the EEInc. issue in this proceeding.

b. AmerenUE has no legal power to compel the extension of the now-expired PSA or to otherwise command EEInc. to sell it power at a below-market price.

Section 6.01 of the PSA expressly provided: "This Agreement shall continue in force through December 31, 2005, unless cancelled pursuant to the provisions of Section 6.02."[42] No other provision of the PSA ever provided a mechanism for extending it, and no other provision of the contract ever gave the signatories a continuing right to acquire power from EEInc. at a particular price after the PSA expired.

Thus, as of January 1, 2006, the PSA had expired and no legal arrangement of any kind was in place to continue it or to give the Sponsoring Companies the same price for power from EEInc. that they had enjoyed under the PSA. Once the PSA expired, EEInc. was legally entitled to sell power to anyone it chose at a price that reflected the fair value of the power. The fair value of the power is determined by the market value of the power.[43]

Contrary to the other parties' unsupported characterization, not having a cost-based contract to buy EEInc.'s power was the status quo after the expiration of the PSA, and was a function of the operation of the long-agreed terms of the PSA.[44] AmerenUE did nothing to

[41] Direct Testimony of Professor Robert C. Downs at 3: 6-22 (Downs Direct).
[42] Power Supply Agreement Between Electric Energy, Inc. and the Sponsoring Companies, §6.01 (1987).
[43] Downs Rebuttal at 2: 14-16.
[44] Thus it is simply incorrect to suggest that AmerenUE affirmatively took action to increase its fuel costs. *See, e.g.*, Schallenberg Rebuttal at 5: 13-17.

create this state of affairs, except of course to sign the PSA in 1987, an act no one has ever suggested was imprudent.

EEInc. is a corporation, distinct from AmerenUE, and regulated by FERC. It owns the power produced by the Joppa Plant; that is, that power is an asset of EEInc.[45] The sale of that power at the best price possible is a corporate opportunity of EEInc., not AmerenUE.[46] When the market price is higher than the cost-based price, the directors of EEInc. have a legal duty to sell its power at a market price.[47] To concoct some legal power possessed by AmerenUE to revive the PSA or compel EEInc. to sell power at a below-market price, the other parties point to the PSA and to AmerenUE's stock ownership as in some way being the source of such a right. Neither provides the right these parties claim.

c. The PSA was a traditional, long-term purchase power contract that gave the purchasers of power no special ownership-like claim on the power of EEInc.

As we discussed above, it is undisputed that AmerenUE's shareholders, not its ratepayers, paid for the EEInc. stock purchased by AmerenUE. Neither EEInc. nor its Joppa Plant is in AmerenUE's rate base or in any way within the jurisdiction of this Commission. If EEInc. sold its main asset, the Joppa Plant, for a profit, only AmerenUE's shareholders would be entitled to share in that profit.[48] Indeed, if UE sold its shares of stock in EEInc., the Commission would have no jurisdiction respecting that sale at all.[49] Only by including the expense of the purchases of power under the PSA in AmerenUE's cost of service – again, a normal and proper

[45] Downs Surrebuttal at 3: 17; Rebuttal Testimony of Professor Robert C. Downs at 3: 21-4:2; 10:19-11:1 (Downs Rebuttal).
[46] Downs Surrebuttal at 3: 18-19
[47] Downs Rebuttal at 3: 21-5: 4; 10:19-11:3
[48] *See, e.g., In re: Missouri Cities Water Co.*, 26 Mo. P.S.C. (N.S.) 1(May 2, 1983); *In re: Assoc. Nat'l Gas Co.*, 26 Mo. P.S.C. (N.S.) 237 (Aug. 30, 1983); *In re: Missouri Cities Water Co.*, 28 Mo. P.S.C. (N.S.) 214 (Apr. 17, 1986); *In re: KCPL*, 28 Mo. P.S.C. 228 (Apr. 23, 1986); *In re: Missouri Cities Water Co.*, 1986 Mo. PSC LEXIS 9 (Sept. 29, 1986); *In re: Missouri Cities Water Co.*, 29 Mo. P.S.C. (N.S.) 178 (July 28, 1987).
[49] See, e.g., *In re: Investigation of Pending Sale of Assets of Aquila, Inc.*, 2004 Mo. PSC LEXIS 231 (Feb. 26, 2004).

action for a prudently incurred expense – can it be said that AmerenUE ratepayers ever paid for anything related to EEInc. The PSA was a relatively typical long-term, purchase power contract with a price that included a capacity charge and an energy charge. These charges included all the fixed and variable costs of producing the power that was purchased. In this regard it was not unique.[50]

As the only point at which AmerenUE ratepayers paid for something related to EEInc., it is on the purchases of power from EEInc. that the other parties focus their attention, claiming that through the otherwise unremarkable PSA AmerenUE's ratepayers acquired some special rights to EEInc.'s power in the future, [in fact forever!] calling it a "jurisdictional power supply resource."[51]

As a matter of law, this claim is meritless. AmerenUE's ratepayers acquired no special interest in, or rights to, EEInc.'s power. There is no basis in fact or law for the bizarre claim that "EEInc. was not operated as a below-the-line investment."[52] Through AmerenUE's purchases of EEInc. power, AmerenUE's ratepayers paid for power and got power in return. Period. As the United States Supreme Court has made clear:

> [c]ustomers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to [sic] capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company. Property paid for out of monies received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock.[53]

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[50] *See, e.g.*, Schallenberg Dep. at 82: 21-24; 84: 17-22.
[51] Brosch Dep. at 26: 23. *See also* Brosch Dep. at 34: 12-15; Brosch Rebuttal at 9: 17-20.
[52] Schallenberg Rebuttal at 6: 19.
[53] *Board of Pub. Util. Commissioners v. New York Telephone Co.*, 271 U.S. 23, 32 (1926). *See also Illinois Pub. Telecommunications Assoc. v. FCC*, 117 F.3d 555, 569 (D.C. Cir. 1997) ("As a general rule, utility service ratepayers pay for service and thus do not acquire any interest, legal or equitable in the property of the company."); *State ex rel City of St. Joseph v. Pub. Serv. Comm'n*, 325 Mo. 209, 223 (1930) (citing *Board of Pub. Util. Commissioners v. New York Telephone Co.*).

Similarly, FERC has explained that, "the fact that a customer pays rates based on the cost of a particular asset [*i.e.*, pays a cost-based rate] does not entitle that customer to share in the gain on the subsequent sale of that asset"[54] because FERC recognizes that "purchases [from a utility] in no way convey[] an ownership interest in the facilities used to provide service."[55]

Moreover, if the PSA provides the kind of extra entitlement the other parties claim, then every prudently incurred, long-term purchase power contract, which is indistinguishable from the PSA for these purposes, should convey that entitlement. This would mean that the purchase of firm power by AmerenUE from Arkansas Power & Light (AP&L) should give AmerenUE ratepayers ongoing "rights" to a preferred price for power from AP&L's generating plants beyond the term of the contract. This is not, and never has been, the case. Likewise, the PSA does not give ratepayers the rights the other parties claim.

A contract pricing mechanism for the sale of any commodity, like the PSA, does not give the buyer ownership rights of any kind concerning the assets of the seller or that commodity (whether those rights are embodied in a newly minted "regulatory asset" or not). Nor does it create legal entitlements beyond the term of the contract.[56]

In short, the only money AmerenUE's ratepayers have expended regarding EEInc. are prudently incurred expenses for power purchased from EEInc. under the PSA. Such expenditures do not give AmerenUE or its ratepayers any claim to a below-market price for that power after the PSA has expired.

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[54] *Southern Cos. Servs., Inc.,* 69 FERC ¶ 61,437 at 62,560 (1994) (finding it is well-settled that customers only pay for service; they do not obtain, by their payments, an entitlement in a utility's assets). *See also Duke Power Co.,* 48 FERC 1384, 1394-95 (1972), *reh'g denied*, 49 FPC 406 (1973).

[55] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils. And Recovery of Stranded Costs by Pub. Utils. And Transmitting Utils.,* Order No. 888, FERC Stats. & Regs. ¶31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶31,048 at 30,438 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶61,046 (1998), *aff'd in relevant part, Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002).

[56] Downs Surrebuttal at 4:10-14.

d. AmerenUE's ownership of EEInc. stock does not give it any legal power to command EEInc. directors to sell EEInc.'s power to AmerenUE at a below-market price.

AmerenUE owns 40% of EEInc.'s stock. EEInc.'s Board of Directors consists of seven members, five of whom are employees of Ameren Corporation or its affiliates.[57] From these facts the other parties argue that it was *AmerenUE's* "imprudent decision" to sell EEInc.'s power into the open market, and that AmerenUE had the right to command its "representatives" on EEInc.'s Board to vote to sell EEInc.'s power at cost-based rates.[58]

Several legal conclusions form the core of this argument: (1) that AmerenUE had the legal right to continue the power supply contract with EEInc.; (2) that the shareholders of a corporation are entitled to direct the corporation to enter into contracts with the shareholders; and (3) that AmerenUE as a large shareholder could have and should have forced the issue by insisting that directors of EEInc. who were also affiliated with AmerenUE vote to continue the contract for the benefit of AmerenUE. Each of these legal conclusions is *wrong*. AmerenUE has not acted imprudently or inequitably, as the other parties claim, for the simple reason that it did not have the legal ability to compel the EEInc. Board to sell EEInc.'s power at a below-market price. Indeed, if the EEInc. directors acquiesced to such a command, they would violate basic legal rules governing a director's responsibility to the corporation he serves.

Again, the PSA expired, by operation of law and in accordance with its own terms, on December 31, 2005. No contract provision, law, or regulation gives AmerenUE any right to command EEInc. to reinstate the PSA or to sell EEInc.'s power on similar terms, specifically, at a below-market price.

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[57] Downs Direct at 6: 3-8.
[58] Schallenberg Rebuttal at 16: 21-24; Schallenberg Dep. 26: 13-20.

EEInc. is an Illinois corporation distinct from AmerenUE. It is not a division of AmerenUE; it is not bound to serve AmerenUE's interests; and it is not in any other way subordinate to AmerenUE. Like all boards of directors, EEInc.'s Board has the ultimate responsibility for managing the business affairs of EEInc. Shareholders are not entitled to manage a corporation in which they own stock.[59]

Directors have legal duties and obligations that arise from sources of law outside the corporation or the documents creating the corporation and governing its operations, such as bylaws. These other sources of law include statutes and the common law. These other sources of law are superior to corporate documents. This means, for example, that bylaws cannot override legal duties imposed by statute or the common law.[60]

EEInc.'s Directors, like all corporate directors, have a duty of undivided loyalty to EEInc. and a fiduciary duty to EEInc.[61] In the corporate governance context, to owe a fiduciary duty means to act in accordance with two key principles: to act in the best interest of the corporation and its shareholders and, similarly, to be loyal to the corporation and to those shareholders and their interests.[62]

EEInc. essentially does one income-producing thing and one thing alone: it produces power. That power is a corporate asset of EEInc., and selling that power at a fair market price is a corporate opportunity of EEInc. In order to make the most profit it can (that is, taking advantage of that corporate opportunity), which after all is what for-profit entities are bound to do for shareholders, it needs to sell as much of that power as it can at as high a price as it can on

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[59] Downs Surrebuttal at 2: 13-19. *See, e.g. Saigh v. Busch*, 396 S.W.2d 9 (Mo. App. E.D. 1965); *Hall v. Woods*, 156 N.E. 258 (Ill. 1927).
[60] Downs Surrebuttal at 2:20-3:3.
[61] Downs Surrebuttal at 3:4-7. *See, e.g. Forinash v. Daugherty*, 697 S.W.2d 294 (Mo. 1985); *Ramacciotti v. Joe Simpkins, Inc.*, 427 S.W.2d 425 (Mo. 1968); *IOS Capital, Inc. v. Phoenix Printing, Inc.* 808 N.E.2d 606 (Ill. 2004); *Levy v. Markal Sales Corp.*, 643 N.E.2d 1206 (Ill. 1994).
[62] Downs Direct at 9: 19-22.

the open market while producing that power at as low a cost as it can. That is how this business makes money. If EEInc. does those things, it will maximize shareholder value. It is the duty of EEInc.'s Board to do just that. Therefore, when presented with the opportunity to sell power at higher market prices versus at lower cost-based rates, the Board has only one course available to it consistent with its fiduciary duties to shareholders – to sell at market. That decision is also in the best interest of AmerenUE's shareholders because if EEInc. maximizes its profits the value of AmerenUE's investment in EEInc. is also maximized.[63]

If the directors affiliated with AmerenUE on EEInc.'s Board force EEInc. to sell power to AmerenUE at cost, the Board is no longer maximizing the value of its shareholders' investment. Instead, EEInc.'s Board would be making decisions to favor the interests of *non-shareholders*; in this case, Missouri retail ratepayers. Consequently, a decision by the EEInc. Board to continue to sell power at cost when it now can sell power at market at a greater profit shifts value that *belongs to* EEInc. shareholders away *from* those shareholders *to* retail ratepayers. This will lower the value of AmerenUE's investment in EEInc., which, in turn, makes AmerenUE's stock less valuable. This effectively harms the Ameren Corporation shares held by millions of members of the public, including nearly 30,000 Missourians.[64]

It is not uncommon for corporations that have large shareholders to have directors who are employees or directors of the large shareholders. In addition, a corporation will often seek as directors individuals experienced in business who are currently employed by, or on the boards of, other corporations. Such directors are in clear conflict of interest situations whenever there is a transaction that involves both corporations. In this case, AmerenUE is a large shareholder of EEInc. and there are over-lapping officers and directors. Nevertheless, such directors are not

[63] Downs Direct at 10: 13-11: 1; Downs Surrebuttal at 3: 17-19.
[64] Downs Direct at 11: 6-15.

"representing" in the deliberations of the Board the interests of the other corporation with which they are affiliated. It is absolutely clear that the directors of EEInc. have fundamental fiduciary duties to EEInc., to the exclusion of any other interest, when they are acting as Directors of EEInc. Those fiduciary duties are not reduced to account for their positions with the major shareholder (AmerenUE, or Ameren Energy Resources, an AmerenUE affiliate).

Directors may be called upon to wear two hats, but they can legally only wear one hat at a time. A director's use of corporate assets to further his own goals or to take the corporation's assets to help another corporation in which he has an interest is a violation of his fiduciary duties. Thus, EEInc.'s Directors who have some interest in AmerenUE cannot legally vote to sell EEInc.'s power to AmerenUE at a below-market price. It would be legally impermissible for AmerenUE to insist, through coercion or direction of its employee/directors, that EEInc. sell its assets (that is, the Joppa Plant power) to AmerenUE for less than fair market value.[65]

AmerenUE has a similar issue with its own shareholders. Even if it has improperly forced EEInc. to sell its power to AmerenUE for less than fair value, AmerenUE could not properly then transfer that value to customers for less than fair value, absent a commercially reasonable business reason that would benefit the company and its shareholders.[66]

These legal principles reflect a basic sense of fairness. One who puts up the investment and takes the investment risk ought to receive the benefits of that investment.[67] From a corporate governance standpoint, that principle of fairness is expressed in terms of fiduciary

[65] Downs Surrebuttal at 4: 4-9. *See, e.g.,Weinberger v. UOP, Inc.*, 457 A.2d 701 (Del. 1983).
[66] Downs Rebuttal at 4: 8-12, 5:20-6:12; Downs Surrebuttal at 3: 9-16.
[67] *See Democratic Central Comm. of the District of Columbia v. Washington Metropolitan Area Transit Comm'n,* 485 F.2d 786, 806 (D.C. Cir. 1973) ("[T]he right to capital gains on utility assets is tied to the risk of capital losses.").

duties: it would be a violation of the fiduciary duties of the directors of EEInc. to improperly shift shareholder benefits to ratepayers.[68]

Witnesses for the other parties try to support their notion that AmerenUE has an enforceable entitlement to the Joppa Plant power at a cost-based price by reference to a provision in EEInc.'s bylaws.[69] Those bylaws, Article II, Section 6, merely describe what voting rights shareholders have, and what voting percentages are required to take certain actions for the corporation. It is clear from that provision that the shareholders of EEInc. could, with a 75% vote, change the allocation of excess power from the Joppa plant that EEInc had previously established. Of course, if EEInc can change the allocation, it would be inappropriate to describe any particular allocation as a "right" of the shareholder. Moreover, those bylaws do not provide for any shareholder right to buy power at cost from EEInc. in perpetuity. Indeed, they do not even address the price for the Joppa Plant's power.[70] To the extent that shareholders had rights and obligations regarding the purchase of Joppa plant excess power, those rights were described in the Power Supply Contract, and terminated when that Contract expired on December 31, 2005.[71]

The other parties also refer the EEInc.Ddirectors who were affiliated with Kentucky Utilities (KU) voting to have EEInc. sell its power at a below-market price.[72] While there is no evidence in this proceeding concerning the motivations of the KU-affiliated directors in taking this maneuver (especially because they did not command a majority of the Board), those directors have the same duties, and are obviously subject to the same kind of conflict of interest, as the AmerenUE-affiliated directors. It is as true for the KU-affiliated directors as it is for the

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[68] Downs Direct at 12: 13-18. *See, e.g. Graham v. Mimms,* 444 N.E.2d 549 (Ill. 1982).
[69] Schallenberg Rebuttal at 21: 23-22:24.
[70] Schallenberg Dep. at 52: 17-19.
[71] Downs Rebuttal at 8:18-9:6.
[72] Schallenberg Rebuttal at 17: 16-17.

AmerenUE-affiliated directors that a sale of EEInc.'s major income producing asset to anyone, including shareholders, for substantially less than its fair market value, under circumstances that permitted sales at fair market value, could not pass muster under the legal rules governing the actions of directors. If the position of the KU-affiliated directors had prevailed, the resulting action by the Board would have violated their fiduciary duties to the corporation.[73]

C. THE PROPOSED EEINC. ADJUSTMENT WOULD VIOLATE THE CONSTITUTION.

i. The Commission may not set rates that interfere with FERC's Order authorizing EEInc. to sell power at market-based rates.

The Federal Power Act (FPA) vests in FERC exclusive jurisdiction over "the transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce."[74] In enacting the FPA, the U.S. Supreme Court has made clear, "Congress has drawn a bright line between state and federal authority in the setting of wholesale rates and in the regulation of agreements that affect wholesale rates."[75] States may not "regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable rates and to ensure that agreements affecting wholesale rates are reasonable."[76] State regulation that entrenches upon FERC's jurisdiction is preempted by operation of the Constitution's Supremacy Clause.[77]

The proposed adjustment here would, if adopted, conflict with FERC's jurisdiction in a way far more objectionable than even the state regulatory actions that the Supreme Court has found preempted in its leading FPA preemption cases. Whereas in those cases the preemption

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[73] Downs Surrebuttal at 16: 11-21.

[74] 16 U.S.C. § 824(b). On the exclusivity of FERC's jurisdiction over these matters, see, *e.g.*, *Mississippi Power & Light Co. v. Moore*, 487 U.S. 354, 370-74 (1988). *See also Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm.*, 539 U.S. 39, 41 (2003) (explaining that FERC exclusively "regulates the sale of electricity at wholesale in interstate commerce").

[75] *Mississippi Power & Light Co. v. Moore*, 487 U.S. at 374.

[76] *Id.*

[77] *See, e.g., id.*

arose from states' failure to honor "FERC-approved cost allocations between affiliated energy companies"[78] in setting retail rates and similar regulatory actions that defeated FERC-approved rates,[79] the preemption here would arise from regulatory action calculated to defeat the very implementation of a FERC order authorizing market-based power sales.

As noted above, in 2005 FERC authorized EEInc. to sell power at market-based rates approved by FERC.[80] Not even the other parties can plausibly contend that the Commission could, without directly encroaching upon the FERC's exclusive regulatory authority, require EEInc. to sell the Joppa facility's power to AmerenUE under a cost-based contract (or on any other basis for that matter). That would unquestionably deny EEInc. the right to implement the FERC-approved tariff. But it would be no less objectionable—and no less an interference with FERC's order— for the Commission to recoup from an EEInc. affiliate (AmerenUE) the profits that EEInc. earns from the implementation of its FERC-approved tariff. What the Commission may not accomplish *directly* by regulating EEInc.'s conduct, it cannot accomplish *indirectly* through AmerenUE as an EEInc. affiliate.[81] The regulatory encroachment on FERC's jurisdiction to authorize market-based rates is equally objectionable in either case.[82]

The Office of Public Counsel (OPC) itself apparently sees a direct conflict between FERC's order authorizing EEInc. to sell its power at market-based prices and the Commission's authority to address the non-renewal of the PSA through rate adjustments. During the FERC proceedings that resulted in market-based rate authorization for EEInc, the OPC protested that

[78] *Entergy Louisiana*, 539 U.S. at 41.
[79] *See, e.g.*, *id.* at 42-45.
[80] *See* Order Granting Market-Based Rate Authorization in *Electric Energy, Inc.*, 113 FERC ¶ 61,245 (Dec. 8, 2005) (hereafter "FERC Order").
[81] Under the other parties' theory of the case, in fact, regulating AmerenUE and regulating EEInc. is really the same thing. They seek to treat both EEInc. and AmerenUE as instrumentalities of Ameren Corporation (contrary to well-established principles of corporate law).
[82] *See, e.g.*, *Duke Energy Trading and Marketing, L.L.C. v. Davs*, 267 F.3d 1042, 1057 (9th Cir. 2001) (holding that indirect forms of interference with FERC's jurisdiction that have the same "purpose and effect" as direct forms of interference are equally preempted).

approval of the applied-for tariff "would permit EEInc to sell power from the Joppa facility that AmerenUE has historically been entitled to purchase for its retail customers," thereby resulting "in the transfer of benefits from the captive Missouri ratepayers of EEInc.'s affiliate, AmerenUE, to the shareholders of both AmerenUE and Ameren."[83] (While the Commission did intervene in the proceeding before FERC, it did *not* join the OPC in opposing EEInc.'s application seeking market-based rate authority.) If the OPC thought that the Commission could lawfully recover the ratepayers' alleged losses through the ratemaking imputation that it now seeks, then it would have had no reason to protest EEInc.'s application for market-based rate authorization. The OPC is not now in any position to claim that the treatment of EEInc.'s energy sales that it urges the Commission to adopt does not conflict with FERC's order.[84]

ii. The proposed EEInc. adjustment would violate the Commerce Clause.

The Commerce Clause[85] contains both an affirmative grant to Congress to regulate interstate commerce and (by implication) a negative restriction on the states' ability to regulate interstate commerce. The latter resides in what is known as the "dormant" (or "negative") Commerce Clause.[86] State action is *per se* unlawful under the dormant Commerce Clause if, in

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[83] FERC Order at 9 (¶ 28).

[84] AmerenUE anticipates that the OPC will respond that, in rejecting its protest, FERC concluded that the matters raised by the OPC are "better resolved at the state level." *Id.* at 11 (¶ 34). That conclusion, however, in no way speaks to the question of whether the regulatory actions that the OPC now asks the Commission to undertake would be preempted by the FPA. FERC did not address the issue one way or another; and, in any event, it is for the Commission (and reviewing courts), and not FERC, to decide whether the OPC's proposed actions would be preempted.

The preemptive effect of the FPA does not turn on whether FERC addressed the particular matter before the state regulatory commission (here, the rate treatment of EEInc's market-based sales). Preemption turns only on whether the state regulatory action encroaches upon FERC's authority. *See, e.g., Entergy Louisiana*, 539 U.S. at 50 (rejecting the " view that the pre-emptive effect of FERC jurisdiction turn[s] on whether a particular matter was actually determined in the FERC proceedings" and emphasizing that it "matters not whether FERC has spoken to the precise" issue before the state regulatory commission) (internal citations omitted; modifications to text in original).

[85] U.S. CONST. art I, sec. 8.

[86] *See, e.g., American Trucking Ass'n, Inc. v. Michigan Pub. Serv. Comm'n*, 545 U.S. 429, 433 (2005); *Dennis v. Higgins*, 498 U.S. 439, 447 (1991).

purpose or practical effect, it discriminates against commerce "outside that State's borders."[87] Only if the state can establish, "under rigorous scrutiny," that its regulatory actions serve a legitimate state purpose that cannot be achieved by any "other means" will they survive dormant Commerce Clause scrutiny.[88] Rarely can a state make this showing, so exacting is the scrutiny applied to discriminatory state regulation.[89]

Especially objectionable under the Commerce Clause (and therefore clearly subject to *per se* treatment) is state action, as here, calculated to regulate the economic activity outside the state's borders (that is, extraterritorially) for the benefit of instate consumers.[90] The proposed adjustment effectively claims for Missouri the right to regulate to what entities (and at what price) an *unregulated* out-of-state corporation, EEInc., may sell its product -- and worse, as far as the dormant Commerce Clause is concerned, to do so for the benefit of in-state Missouri ratepayers. The other parties can offer no lawful justification whatsoever for this action, let alone one that satisfies the Commerce Clause.[91] Indeed, few regulatory actions as blatantly extraterritorial in their reach as the one proposed here even surface in the case law.

It is of no consequence that the other parties seek to implement their regulatory objectives indirectly, by requiring AmerenUE to compensate ratepayers for the financial consequences of EEInc.'s decision not to sell AmerenUE cost-based power, rather than directly, by requiring EEInc. to sell its power to AmerenUE for the benefit of Missouri ratepayers. The Supreme Court

[87] *Healy v. Beer Inst., Inc.*, 491 U.S. 324, 332 (1989). *See also, e.g.*, *Edgar v. MITE Corp.*, 457 U.S. 624, 642-43 (1982). *See generally* Laurence H. Tribe, 1 *American Constitutional Law* (3d ed. 2000) ("[T]he Court has articulated virtually a per se rule of invalidity for extraterritorial state regulation—i.e., laws which directly regulation out-of-state commerce, or *laws whose operation is triggered by out-of-state events*.") (emphasis added).
[88] *C & Carbone, Inc. v. Town of Clarkstown*, 511 U.S. 383, 392 (1994).
[89] *See, e.g.*, *id.*
[90] *See, e.g.*, *Healy*, 491 U.S. at 336.
[91] It is no defense that the state regulation here would be incidental to the lawful exercise of the Commission's jurisdiction over retail electrical rates in Missouri. *See* Tribe, *supra*, at 1078 ("Extraterritorial state regulation cannot be justified by the bare fact that a state has legal jurisdiction . . . to regulate a transaction."), and cases cited therein.

has condemned as *per se* violations of the Commerce Clause forms of interference considerably more indirect than that.[92]

iii. The proposed EEInc. adjustment would be confiscatory and therefore violate the Takings Clause.

A long line of Supreme Court cases holds that the Fifth Amendment's Takings Clause (applicable to state regulatory action by incorporation under the Constitution's Fourteenth Amendment) entitles a publicly regulated utility to a "reasonable rate of return" on its investment.[93] It is not sufficient for the state to ensure "cost recovery without guaranteeing a fair and reasonable return on investment."[94] "If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so has violated the Fifth and Fourteenth Amendments."[95] The proposed adjustment here would clearly create such a taking.

A public utility cannot, consistent with the Takings Clause, be required to subsidize its customers' rates with assets belong to its shareholders especially where (as invariably happens) the subsidy denies the utility a reasonable rate of return on investment.[96] The proposed adjustment clearly would transfer EEInc.'s assets to AmerenUE ratepayers in violation of that well-established principle and so should be rejected as an unlawful taking.

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[92] *See, e..g.*, Tribe, *supra* note 82, at 1057-84.
[93] *See, e.g., Bluefield Water Works & Improvement Co. v. Public Serv. Comm. of West Virginia*, 262 U.S. 679 (1923). Among more recent cases so holding, see, *e.g., Michigan Bell Telephone v. Engler*, 257 F.3d 587 (6th Cir. 2001).
[94] *Engler*, 257 F.3d at 595.
[95] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989).
[96] See, e.g., *Engler*, 257 F.3d at 594 (holding unconstitutional portions of a state utility statute because it required utilities to subsidize regulated rates with "revenues generated from unregulated services") (citing *Brooks Scanlon Co. v. Railroad Commission*, 261 U.S. 396 (1920), where a state regulatory commission sought to appropriate a railroad's unregulated assets for the public in violation of the takings clause).

iv. The proposed EEInc. adjustment would constitute retroactive ratemaking in violation of the AmerenUE's Due Process rights.

The Commission may not, without violating Due Process rights (or well-established principles of ratemaking under Missouri law), retroactively set utility rates. While retroactive ratemaking usually infringes upon consumers' Due Process rights, it may also infringe upon a utilities' Due Process rights. The latter occurs principally where rates are set to recover from the utility "excess past profits" incorporated into earlier rates.[97]

The adjustment sought by the other parties would constitute an especially objectionable form of retrospective ratemaking. Under the other parties' theory of the case, rates should now be set on the assumption that Missouri consumers have for many years "financially supported" AmerenUE's investment in the Joppa Plant by paying rates to AmerenUE that allowed the Company to recover costs in excess of those prudently incurred in the purchase of power from a third-party source. The other parties claim, in effect, that Missouri ratepayers are now entitled to recoup yesterday's rate-based "investment" by paying lower rates today.[98]

Yet the expense of purchasing power from EEInc. has been included in AmerenUE's cost of service for decades without the slightest objection. Had the purchase of power from EEInc. been in any way imprudent, the Commission would not, of course, have allowed its inclusion in the cost of service. Even if those expenses now could be considered in some way imprudent, the

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[97] *Utility Consumer Council of Missouri, Inc. v. Public Serv. Comm'n of Missouri*, 585 S.W.2d 41, 59 (Mo. 1979). *See City of Joplin v. Public Serv. Comm.*, 186 S.W.3d 290, 299 (Mo. Ct. App. W. Dist. 2005) explaining that the Commission "lacks authority to retroactively correct rates," to "refund money," or "take into account overpayments when fashioning prospective rates"). On the constitutional dimension of the prohibition, see, *e.g.*, *Midwest Gas Users Ass'n v. Public Serv. Comm'n*, 976 S.W.2d 470, 481 (Mo. Ct. App. W. Dist. 1998) (explaining that the Commission may not "redetermine rates already established and paid without depriving the utility . . . of his property without due process"). *See also City of Joplan*, 186 S.W.3d at 299 ("Due process prevents any court or legislative body from taking property of a public utility where that property consists of money collected from ratepayers pursuant to *lawful* rates.").

[98] *See, e.g.*, Rebuttal Testimony of Robert E. Shallenberg (Jan. 31, 2007), at 6.

Commission cannot now, many years later, recoup the "overpayment" by adjusting current and future rates. To do that would clearly be to transgress the prohibition on retroactive ratemaking.

D. EEInc. - Conclusion

There simply is no basis in law or equity to make the adjustment to AmerenUE's cost of service related the expiration of the EEInc. PSA proposed by the other parties. What is going on here is clear. Fifty years ago the shareholders of AmerenUE and the other Sponsoring Companies took a serious, unprecedented risk to participate in a new and important national defense initiative – they flipped a huge coin. In doing so, they did not put their ratepayers' resources on the line.

Now we know that these enterprising utilities won their bet – that coin has come up heads. Moreover, the wholesale power world has been transformed in ways those utilities could not have anticipated when they first tossed that coin. As a result, the new wholesale market now offers to reward their success with EEInc. As a matter of fairness and law, they are entitled to that reward.

Having now seen the result of the EEInc. coin toss, and greatly benefited from that success over past decades in a contractual relationship that was a creature of the old wholesale power world, the other parties in this proceeding want to continue that now-expired relationship in some fashion. Facing the barrier of traditional regulatory treatment of purchase power contracts, of no ratepayer investment in EEInc., and of the fundamental duties of corporate directors and officers, the other parties create mythical "regulatory assets," impugn AmerenUE's motives in complying with the law, and otherwise strain to gin up some entitlement to EEInc.'s power at prices significantly below its current value. These efforts are neither fair nor lawful; they should be rejected.

2. Callaway Non-Labor Maintenance Expense: Should Callaway refueling non-labor maintenance expense be based on an average of the last three refuelings or on the most recent refueling as the appropriate level given Callaway's total operating and maintenance expenses?

This issue involves certain contractor, consultant, material and rental costs AmerenUE incurs during refueling outages for the Callaway nuclear plant. Staff allowed $21.5 million for this item, which reflects the actual amount of such costs AmerenUE experienced during the Callaway Plant's most recent refueling (Refuel 14), which occurred in the Fall of 2005. (Rutz, rebuttal, p. 2). Because Callaway refuelings are scheduled every 18 months, 2/3 of this amount is included in the Staff's calculation of the Company's cost of service to reflect an annual amount.

The Company believes that this amount does not reflect a normalized level of these costs for two reasons. First, Refuel 14 was an extremely unusual outage because the primary focus during this outage was the replacement of the Callaway Plant's four 400-ton steam generators and turbine rotors. This was the most extensive capital project undertaken since the plant was commissioned, and it resulted in a 63-day outage. (Naslund, direct, p. 6.) Because of the focus on these significant capital projects, the Company deferred a number of maintenance projects during Refuel 14 that are expected to be completed in Refuel 15. These projects include steam generator tube inspections (which is anticipated to cost almost $5 million), reactor vessel cold leg in-service inspections (anticipated to cost nearly $700,000) and other projects. (Rutz, rebuttal, pp. 2-3.) The deferral of these maintenance projects means that non-labor maintenance expense was unusually low in Refuel 14.

Second, due to unusual circumstances, the Company was able to reduce its non-labor maintenance costs for Refuel 14 by utilizing the services of its General Construction and Outage Management Group in lieu of contractors. This group was formed to support plant outages and general construction for AmerenUE's fossil plants, but because there were no fossil plant outages during the same time period as Refuel 14, the Company was, for the first time, able to use this group to support the nuclear plant outage. For future outages, the Company will have to use contractor personnel to perform this work, which will add a minimum of $3 million to the outage cost. (Rutz, rebuttal, pp. 3-4.)

For these reasons, the Company believes that the Staff's use of non-labor maintenance costs from Refuel 14 is not representative of the level of these expenses that will be incurred on an ongoing basis. The Company's recommendation is to use an average of the non-labor maintenance costs incurred over the last three refueling outages (Refuels 12-14) which equals $28.1 million.

3. Fuel and Purchased Power Expense:

A. Should diesel fuel hedge costs be included in the cost of service?

B. Should nuclear fuel costs include the cost of new fuel assemblies?[99]

C. What amount should be included in rates to reflect the unamortized balance of nuclear fuel assemblies in the reactor?

i. Diesel Fuel Hedge Costs.

The Staff has proposed to exclude the cost of heating oil futures call options the Company purchases to hedge its exposure to increases in the cost of diesel fuel which flow through the Company's coal transportation contracts with railroads. As Company witness Robert Neff explained in his direct testimony, diesel fuel adjustment riders have become mandatory in contracts with AmerenUE's two primary coal transporters, the Burlington Northern-Santa Fe and the Union Pacific railroads. To hedge its exposure to diesel fuel cost

[99] The Company is not briefing this issue because as of this writing the Company believes it has reached a settlement in principle with Staff (the only party with whom an issue existed). If necessary, the Company would later supplement this brief on this issue.

escalations, the Company has purchased heating oil futures call options. The Company uses heating oil options to hedge its exposure because no diesel fuel options are available, and the cost of heating oil has been shown to have a 96% correlation with the On-Highway Diesel Index. Any financial gains derived from the purchase of the heating oil options are used to offset the potentially significant impact of diesel fuel cost increases. (Neff, direct, p. 33.) The Company believes that its use of hedging instruments for this purpose is reasonable and prudent, and it is entirely consistent with the Commission's encouragement of the use of hedging instruments in its purchased gas adjustment rules and its recently enacted fuel adjustment clause rules. (4 CSR 240-40.018; 4 CSR 240-20.090(1)(B)). Options for 2007 were purchased prior to January 1, 2007, so these costs were unquestionably known and measurable within the update period for this case.

Staff witness John Cassidy has proposed the exclusion of these costs basically on the ground that the hedges only serve to protect shareholders against the impact of fuel cost increases. (Cassidy, surrebuttal, p. 8.) In the Company's view, this is clearly not the case. For one thing, if the Commission approves a fuel adjustment clause in this case as recommended by the Company, any increases in coal transportation costs caused by the diesel fuel adjustment mechanism would almost immediately flow through to customers. Under those circumstances, it would clearly be to customers' benefit to have the protection against spikes in the cost of diesel fuel that the heating oil options provide. Even if no fuel adjustment clause is approved, the Company believes that its actual, prudently incurred cost of hedging diesel costs should still be included in its cost of service. In the absence of a fuel adjustment clause, diesel costs will be recognized in the Company's next rate case, probably at a normalized level. If the Company does not hedge its exposure to price increases, any cost increases that occur will ultimately be passed on to customers in future cases. In that respect, the cost of hedging this exposure is really no different than other types of insurance expenses that are routinely included in utilities' cost of service. AmerenUE's gas customers have benefited considerably from the use of hedging mechanisms to dampen gas price spikes, and there is no reason to believe that electric customers will not benefit from the use of options to hedge risk in this situation. The Staff has made no showing that the use of these options as a hedging mechanism is in any way unreasonable, imprudent or improper, and therefore these costs should be included in the Company's cost of service.

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

5. 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 should be authorized to use a fuel adjustment clause as outlined in Mr. Lyons' testimony. As Mr. Lyons' testimony demonstrates, when the Missouri Legislature enacted Senate Bill (SB) 179, it removed Missouri from the list of just two other non-restructured states that do not utilize fuel adjustment clauses (FAC) for their electric utilities and provided the Commission access to a mainstream regulatory tool. By imposing, among other things, the requirement that a full rate case occur every four years to review the operation of the FAC, the Legislature built in safeguards and protections that are nearly unprecedented among the now 28 out of 30 non-restructured states that allow FACs.[100] As Mr. Lyons' Rebuttal Testimony discusses, FACs are also actually used in these other non-restructured states. In fact, as documented in Schedule MJL-4, FACs are utilized by the large majority of utilities in other non-

[100] See Schedule MJL-3-3 attached to Mr. Lyons' Rebuttal Testimony.

restructured and Midwestern states, including almost all other utilities that, like AmerenUE, heavily rely on coal-fired generation.

In addition to the safeguards provided by the Legislature, the Commission provided rules with even further consumer protections,[101] which include: use of historic versus projected fuel prices as a basis for setting the FAC tariffs, the opportunity for just four FAC adjustments per year versus twelve used in many states, and extensive minimum filing and ongoing surveillance requirements, among other things. AmerenUE, as discussed in the Direct, Rebuttal, and Surrebuttal Testimonies of Mr. Lyons, has addressed the minimum filing requirements, has explained in detail how AmerenUE's proposed FAC would operate and ultimately how major intervenor concerns could be addressed through a substantial compromise FAC. That compromise FAC, as discussed in Mr. Lyons' Surrebuttal Testimony, requires: off-system sales (OSS) to be netted against fuel costs to allay fears that OSS would mitigate fuel price volatility but, under traditional ratemaking, be retained by AmerenUE to benefit shareholders; just three FAC adjustments per year versus the four allowed under Commission rules in order to alleviate administrative reviews; recovery of deferred balances over twelve months versus the three months originally proposed by the Company in order to mitigate volatility to the consumer; and further, deferrals of net fuel cost increases that would cause consumers' bills to rise more than 4% on average per year with recovery of such deferrals over a later twelve month period. In short, AmerenUE has offered modifications to its originally proposed FAC that address intervenor concerns and offers consumer protections beyond those contained in either SB 179 or the Commission's rules. AmerenUE is in an extreme minority of utilities in the Midwest and nationally, many with a mix of generation resources much like AmerenUE, that do not have an

[101] See Schedule MJL-3 attached to Mr. Lyons' Rebuttal Testimony.

FAC. The Company has proposed an FAC that very well may be the most consumer friendly FAC in the country and it should be granted use of such an FAC.

The principal arguments made against adoption of an FAC for AmerenUE are, at bottom, quite similar to the arguments made by those who entirely or almost entirely opposed adoption by this Commission of rules that would allow this Commission to approve FACs for utilities under its jurisdiction, as contemplated by SB 179. A new twist, or perhaps one that is now being emphasized by these parties more, is that use of an FAC would just be too hard, too complex, for the Commission to handle. As Mr. Lyons' testimony discusses, the Company does not share the apparent lack of faith in the Commission's ability to administer FACs, just like the state utility commissions in nearly every other state already do.

Another argument made against adoption of an FAC for AmerenUE comes from the Staff, but it is based upon a flawed argument that an FAC would not be needed because increases in OSS profits would offset fuel cost increases. As shown in AmerenUE witness Shawn E. Schukar's Surrebuttal Testimony, the proposition that OSS profits would increase (decrease) in lock step with increases (decreases) in fuel costs is not only counter-intuitive, but also entirely inconsistent with the facts.

It is also noteworthy that Staff's and others' testimony on this issue suggests that perhaps AmerenUE's fuel costs are not volatile enough for use of an FAC. Perhaps only those utilities which made generation choices that now cause them to rely on fuels with more volatile prices and which have been questioned rather strongly by this Commission (i.e., substantial investment in gas-fired generation to serve baseload needs) might have an even greater need for an FAC than a utility, like AmerenUE, whose resource mix has provided significant benefits to its customers and the state – and which, to the Company's knowledge, has not been the subject of much, if any, criticism at all. However, it would seem to be a poor regulatory policy position to deny AmerenUE the use of a mainstream regulatory tool because of the good decisions made by AmerenUE over the preceding decades. Importantly, however, as AmerenUE witness Robert K. Neff and Mr. Lyons discuss in their February 5, 2007 Rebuttal Testimonies, significant changes have taken place in fuel markets (in particular, in coal markets relied upon heavily by AmerenUE). They reflect not only increases in costs, but increased volatility in those costs. These circumstances further justify implementation of an FAC.

As noted above, AmerenUE, in response to concerns and suggestions made by a number of parties in their Direct and Rebuttal Testimonies, has agreed to make several modifications to its FAC proposal, all of which reflect a move toward these various parties' positions. The Company has taken the approach suggested by Missouri Industrial Energy Consumers (MIEC) witness Maurice Brubaker and, to the extent the Commission grants an FAC, by Staff, and proposes netting OSS revenues against fuel costs in the FAC. AmerenUE proposes that this FAC be coupled with a sharing of net fuel cost savings which will maintain appropriate incentives for areas within the Company's control. These incentives would help maintain low rates by encouraging further performance gains by the Company, but also yield immediate shared savings benefits for customers that are more than twice as large as the maximum share of savings the Company could realize. Indeed, even if the Company were able to maximize its share of fuel cost reductions, it would only modestly enhance the Company's ROE (up to a limit of approximately 100 basis points, assuming all other costs and revenues remain the same). Moreover, before the Company has any chance of benefiting from any net fuel cost savings, the Company must first improve efficiency, reduce fuel-related costs, or generate OSS revenues that offset the already known significant fuel cost increases faced by the Company in coming years.[102] Mr. Lyons discusses this proposal in detail in his Surrebuttal Testimony, as does Mr. Baxter in his Surrebuttal Testimony. As Messrs. Lyons and AmerenUE witness Warner L. Baxter also point out, the Company would also find its original "traditional" treatment of OSS or its originally outlined alternative OSS margins sharing mechanism acceptable, if that were the Commission's preference. However, the Company has outlined its proposal to net OSS revenues against fuel costs with a net fuel cost savings sharing mechanism in response to other parties' preference to net those revenues against those costs.

In response to concerns expressed principally by Noranda Aluminum, Inc. witness Donald Johnstone (and to some extent by OPC witness Russell Trippensee), the Company has agreed with Mr. Johnstone's volatility mitigation proposal, with just one modification. This modification applies Mr. Johnstone's suggested 4% cap on annual adjustments to AmerenUE's annual average cents/kWh across *all* customer classes, rather than just for the LTS class under which Noranda takes service. As suggested by Messrs. Johnston and Trippensee, the Company has also agreed to recover FAC adjustments over 12 months, rather than over a quarterly period, to further remove volatility in rates resulting from FAC adjustments.

AmerenUE witnesses Timothy D. Finnell and Mr. Schukar provide testimony with respect to what an appropriate, normalized level of OSS revenues (or OSS margins, as the case may be) would be under the Company's netting proposal or if the Company's originally proposed traditional treatment of OSS or alternative sharing grid were adopted. As the case has progressed, more up-to-date information has become available and the Company has considered the positions of other parties, in particular of Dr. Michael Proctor of the Commission Staff.

[102] Staff witness John Cassidy testifies that known coal and nuclear fuel cost increases from test-year levels through 2009 are in excess of $65 million (Cassidy Rebuttal Testimony, at p. 6, l. 10 through p. 7, l. 7).

As reflected in Mr. Schukar's January 31, 2007 Rebuttal Testimony, the Company agrees in part with some of Dr. Proctor's concerns with Mr. Schukar's originally proposed energy prices used to calculate OSS revenues/margins, but also found that there were adjustments and corrections that had to be made to Dr. Proctor's originally proposed energy prices to make them properly reflect normalized conditions. The Company is now using those adjusted and corrected Dr. Proctor prices, as discussed in Mr. Schukar's Surrebuttal Testimony. The need to adjust and correct Dr. Proctor's prices is corroborated by other data presented in this case.

For example, as shown on Mr. Schukar's Schedule SES-13, the adjusted and corrected around-the-clock Dr. Proctor energy price of $38.04 per MWh is close to the $38.42 per MWh realized price received by AmerenUE at its generators for the 12 months ending January 2007. If the Cinergy hub price is adjusted to reflect the fact that AmerenUE's realized prices at its generators are less than Cinergy prices, the appropriately "basis-adjusted" Cinergy price of $38.54 per MWh is also quite close to the adjusted and corrected Dr. Proctor price.[103] The average prices at AmerenUE's generating stations during the calendar year 2006 were also less than $39 per MWh as shown in Table 3, page 25 of Mr. Schukar's January 31 Rebuttal Testimony.

Consequently, by now using the adjusted and corrected Dr. Proctor price, the Company is using a price that lines up with other available data demonstrating that this normalized test-year price is reasonable. By contrast, Staff continues to use a normalized price of approximately $42

[103] The Cinergy price is a price for a trading hub located away from the site of AmerenUE's generating stations and trades at a premium above AmerenUE's realized prices. As shown in Schedule SES-13 (attached to Mr. Schukar's January 31, 2007 Rebuttal Testimony), the average Cinergy price for twelve months ending January 2007 is $40.05. As illustrated on page 27 of Mr. Schukar's Rebuttal Testimony, Cinergy prices have been trading at a premium of $1.51 above AmerenUE prices. This suggests appropriately "basis-adjusted" Cinergy prices would be approximately $38.54.

per MWh[104] despite the fact that Staff has essentially admitted that these prices are overstated because they do not reflect the prices (e.g., due to congestion and losses) that AmerenUE can actually realize at its generators.[105] In fact, the available pricing data from the corrected Proctor analysis and the 2006 and 12 months ending January 31, 2007 data shows that Staff's OSS prices are overstated by between $3 to $4 per MWh. At an OSS volume of approximately 9.75 million MWh,[106] this means Staff's OSS revenues and OSS margins are overstated by between approximately $29 million to $39 million.

While the difference between the Company's and Staff's OSS margin recommendations has narrowed considerably, the Company continues to believe that Staff overstates a normalized level of OSS margins due to overstated normalized OSS energy prices.[107] Two other parties have also recommended energy prices for use in setting OSS margins, with MIEC witness Mr. James Dauphinais suggesting that 2006 prices at AmerenUE generating stations ($38.54/MWh)[108] should be used as the normalized test-year value of prices. State witness Mr. Brosch suggests that the Commission should throw away the use of normalized, historic test-year information and instead rely upon the Company's 2007 budget, which is inappropriate because, for example, it fails to reflect normalized levels of important variables that determine an appropriate level of OSS for ratemaking purposes.[109]

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[104] As Schedule SES-13 shows, the weighted average of Dr. Proctor's on-peak and off-peak prices based on his Direct Testimony is $41.75 per MWh. However, based on the workpapers supporting Dr. Proctor's Surrebuttal Testimony, Dr. Proctor's the around-the-clock price as implemented by Mr. Rahrer averages to $42.04 per MWh.

[105] Proctor Surrebuttal Testimony at p. 31, lines 10-19.

[106] Proctor Surrebuttal p. 29, l. 16-19.

[107] Much of the difference between Staff's and the Company's position on what an appropriate normalized level of OSS margins is stems from a disagreement on the appropriate energy price to use in their respective production cost models. This is because both the Company and the Staff have reached agreement on a number of modeling errors or changes that existed in the original production cost modeling, which reduced the volume of energy available to sell off-system.

[108] Schedule JRD-Surrebuttal-1.

[109] Incredibly, Mr. Brosch, for the State, makes no attempt to analyze what a normalized level of OSS margins should be but rather, simply latches onto the Company's 2007 budget for OSS margins which is based upon a Cinergy forward price at one day of the year. However, the 2007 budget overstates the prices AmerenUE could

In summary, the Company, by using the corrected and adjusted Dr. Proctor prices (which line up rather closely with other price data points), has addressed the vast majority of the criticisms and concerns expressed by other witnesses about the determination of an appropriate level of OSS in this case. The Company's revised recommendation for OSS margins is $201 million[110]; MIEC's recommendation is approximately $205 million; and if Staff's overstated energy prices are corrected as discussed above, their $245 million OSS margin recommendation is reduced to the $206 million to $216 million range.[111]

In summary, once the errors are corrected, every party with a recommended level of OSS margins (except the State who reached out to grab an un-normalized budgeted amount) basically agrees on what an approximate normalized level of OSS margins should be.

6. Tax: Should "flow through" accounting methodology continue to be used in this case, or should "normalization" methodology be adopted for calculating income tax expense as it relates to net salvage or cost of removal?

This may or may not be a contested issue before the Commission, depending on how certain motions pending as of this writing are decided. The issue arose for the first time in a section of the Surrebuttal Testimony of Staff witness Steve Rackers filed February 27, 2007, and thereafter also was mentioned in "Supplemental Surrebuttal Testimony" attempted to be filed by State witness Michael Brosch. Because of the lateness when this issue arose, Mr. Rackers'

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realize at its generators in any event because the Cinergy prices exceed AmerenUE realized prices, and because it assumes a plant availability level never before achieved by the Company and that far exceeds the volumes both the Company and the Staff recommend for use in setting rates in this case. Use of such "stretch goal" budget numbers is inappropriate and not tied to any other variable upon which rates are set – historic, normalized levels of revenues and costs, historic, weather normalized loads, and normalized plant outage schedules, to name just a few. If it were going to do so, then all 2007 budget items, like higher labor costs, and higher costs for materials and other increased operating and maintenance expenses, etc., would have to be taken into account as well. It is inappropriate for Mr. Brosch to reach forward and grab this one revenue item as the basis for setting rates in this case.

[110] The Company had inadvertently failed to correct one modeling problem relating to the normalized duration of Callaway outages at the time it filed its Surrebuttal Testimony and also has removed the "sales limits" from its model, thus raising its OSS margin recommendation to $201 million. When fuel costs are trued-up as part of the true-up phase of the case, OSS margins modeled by the Company and Staff may change slightly.

[111] If only Staff's suggested 2% reduction in prices were implemented, that 2% reduction in OSS price would reduce Staff's OSS margins by over $7 million to approximately $238 million. However, as explained above, that 2% reduction is inadequate to fully reflect the errors in Staff's pricing.

testimony on this issue should be stricken and the filing of State witness Michael Brosch's testimony should not be allowed under the Commission's rule that requires Surrebuttal Testimony be limited to issues addressed in earlier-filed testimony. Also because of the lateness of when this issue is being raised, AmerenUE has not had a chance to prepare any testimony on it.

For many years in contested cases before this Commission, Staff took the position that "flow through" accounting should be used for calculation of income tax expense as it related to cost of removal or net salvage. Some companies took the position that the alternative accounting method, "normalization," should be used.[112] The Commission, after many arguments on this issue, stated its resulting rule thus: "The Commission is of the opinion that normalization tax treatment is warranted only when the utility requesting same can demonstrate significant cash flow difficulties."[113]

Subsequent to the cases just discussed, the accounting treatment of net salvage in income tax expense calculations has been addressed in a variety of Commission cases, some of them influenced by multiple changes in the Internal Revenue Code.[114] FERC also has addressed the issue at different times, for example in *Southern California Edison Co.*, Docket No. ER79-150-003, 1981 FERC LEXIS 3276, 31-35; *Kansas City Power and Light Co.*, Docket No. ER80-315-000, 1982 FERC LEXIS 1127, 108-117 (entire section of FERC order is entitled "Normalization

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[112] *See, e.g., Central Telephone Co.*, Case No. 18,698, 1977 Mo. P.S.C. 335, 342-45; *Southwestern Bell Telephone Co.*, Case No. TR-77-214, 1980 Mo. P.S.C. LEXIS 48, 20-21; *St. Joseph Light and Power Co.*, Case No. ER-81-43, 1981 Mo. P.S.C. LEXIS 31, 58-63 (entire section of Order, covering 6 pages, is entitled "Flow Through Versus Normalization"); *Southwestern Bell Telephone Co.,* Case No. TR-81-208, 1981 Mo. P.S.C. LEXIS 4, 65-73 (entire section of Order, covering 9 pages, is entitled "Normalization vs. Flow Through of Income Taxes"); *United Telephone Company*, Case No. TR-80-235, 1981 Mo. P.S.C. 152, 160-61.
[113] *Southwestern Bell Telephone Co.*, Case No. TR-81-208, 1981 Mo. P.S.C. LEXIS 4, 72.
[114] *See, e.g., Southwestern Bell Telephone Co.*, Case No. TR-82-199, 1982 Mo. P.S.C. LEXIS 3, 77-82; *Missouri Public Service Company*, Case No. ER-82-39, 1982 Mo. P.S.C. LEXIS 36, 41-43; *Southwestern Bell Telephone Co.*, Case No. TR-83-253, Mo. P.S.C. LEXIS 4, 27-29 (1983); *Southwestern Bell Telephone Co.*, Case No. TC-89-14, Mo. P.S.C. LEXIS 13, 32-33 (1989); *Utilicorp United, Inc.*, Case No. ER-90-101, Mo. P.S.C. LEXIS 34, 58-61 (1990); *Southwestern Bell Telephone Co.*, Case No. TC-93-224, 1993 Mo. P.S.C. LEXIS 62, 47-49.

Versus Flow-through of Taxes Associated With Removal Costs"). None of these cases contains any ruling compelling particular accounting treatment of net salvage in the income tax expense calculation in this case, and it should be noted that even in the "Supplemental Surrebuttal Testimony" which Mr. Brosch sought permission to file just six working days before commencement of the hearing, he does not assert that there is any binding statutory rule or pronouncement of this Commission that governs this issue in this case.

Perhaps because of the rarity of rate cases involving AmerenUE, in fact no Commission ruling on this issue has been made pertaining to AmerenUE.

AmerenUE witness Charles A. Mannix explains that the Company's position is based upon "flow through" methodology, and that this is the historical treatment given to the issue by both the Company and by Staff. ("Q. Why is the flow through method being used? A. This has been the traditional method used by both the Staff and the Company for preparing the Income Tax Expense Calculation." Surrebuttal Testimony of Charles A. Mannix, page 4, lines 15-17).

Staff witness Steve Rackers admits that the Staff's calculations from the outset in this case up until the date his Surrebuttal Testimony was filed, February 27, 2007, were based upon "flow through" methodology on the issue of how to treat net salvage in the income tax expense calculation. ("In its original calculation of income tax expense, the **Staff** added back the amount of accrued net salvage (salvage received less cost of removal) included in its annual amount of depreciation expense and deducted the amount of net salvage experienced as a result of actual plant retirements. **This resulted in "flow through" treatment for the timing difference associated with net salvage.**" Rackers Surrebuttal Testimony, page 4, lines 10-14 (emphasis added)).

The methodology used in this case, and acknowledged to have been used both by AmerenUE and by Staff, up until a few days before the hearing, should be approved by the Commission. Doing otherwise would be inconsistent with the Commission's own rule requiring that the parties present their full cases in chief in direct and rebuttal testimony and that surrebuttal testimony be limited to those issues raised in rebuttal, 4 C.S.R. 240-2.130, and would constitute a failure by the Commission to perform its statutory duty to "determine and prescribe just and reasonable rates." §§ 393.140 (5) and 393.150.2 RSMo (2000), since presenting the issue for the first time in surrebuttal testimony deprives the Company of an opportunity to litigate the issue in an orderly fashion.

7. Should AmerenUE include wind power in its generation portfolio? If so, how much?

There does not appear to be opposition to AmerenUE's proposal to add 100 MW of wind to the Company's generation portfolio by any party in this case, although some parties would like to see more than 100 MW of wind power added to the Company's generation portfolio.[115] First, it is important to note that the process necessary to install the 100 MW of wind power is already well underway. On January 31, 2007, the Company issued a Request for Proposals (RFP) for 100 MW of wind power.[116] This RFP had been reviewed by all parties to AmerenUE's IRP docket, Case No. EO-2006-0240 (the IRP case), including Staff, OPC and DNR. All parties were encouraged to submit comments and suggestions to the Company. AmerenUE then worked those comments and suggestions into the RFP prior to it being issued. Bids were due back to the Company by February 28, 2007, and the Company will review and evaluate all bids that were received. As part of the IRP process, AmerenUE will share both the bids received and its evaluation of those bids with the parties to the IRP case.

[115] Direct Testimony of Brenda Wilburs at 13:20-23. Rebuttal Testimony of Lena Mantle at 2:17-19.
[116] Surrebuttal Testimony of William J. Barbieri at 4:5-10.

The resolution of the question of the proper level of wind power as a portion of AmerenUE's generation remains to be determined. The results of the current RFP process will provide valuable information about wind in the Company's service territory for use in its resource planning process and will enable the Company to properly evaluate the appropriate level of wind generation to place in its resource portfolio. This evaluation will occur within the Company's long-term planning process. As provided for in the Stipulation and Agreement in the IRP case, the Company will evaluate the value of wind to determine the appropriate level of wind power for AmerenUE's generation portfolio[117]. A rate case is not the appropriate vehicle for determining the appropriate level of wind power generation for AmerenUE. That type of analysis should be left in the long-term planning process, as contemplated in the Stipulation and Agreement approved by the Commission in the IRP case.

8. Demand-Side Management:

A. Should AmerenUE set megawatt and megawatt hour goals for Demand Side Management? If so, what should those goals be?

B. Should AmerenUE fund Demand Side Management programs at minimum levels? If so, at what levels?

C. How should DSM programs be selected?

The Direct Testimony of Michael Moehn indicates the Company's desire to explore the options of funding appropriate demand side management (DSM) programs.[118] Beyond this specific commitment, the Stipulation and Agreement approved by the Commission in the IRP case sets forth a process for evaluation of demand-side management programs in order to determine what programs should be implemented. This detailed analysis is designed to seek input from the all parties. AmerenUE has already hired a consultant to lead the process and has

[117] Stipulation and Agreement, EO-2006-0240, filed January 5, 2007.
[118] Direct Testimony of Michael Moehn at 16:8-20.

begun the workshop process.[119] All parties in the IRP case were included in and concurred in the selection of the consultant. In addition, the entire IRP planning process is being approached in a much more participatory manner. Several workshops with all parties in the IRP case have been or are scheduled to be held on various topics prior to finalization of the IRP plan. It is the desire of the Company that all parties have input into the development of AmerenUE's next IRP in the hopes that all parties become comfortable with and have confidence in the end result.[120] This end result will be the primary driver of AmerenUE's funding of future DSM programs.[121]

Despite the Company's desire to allow the IRP process to drive its commitment to DSM programs, the Company is willing to commit to a minimum level of funding as a demonstration of its good faith intentions in this area. In the Surrebuttal Testimony of AmerenUE witness Michael Moehn, the Company has committed to a minimum level of funding, $13 million, for DSM programs in the first year.[122] Mr. Moehn also recommends that the minimum amount ramp up to $20 million by the year 2010.[123] While the Company believes the final spending level for DSM is best determined through the IRP process, it also believes a minimum spending level, one that is rational and supported by industry experience, can demonstrate AmerenUE's desire to appropriately fund DSM programs as it moves through its IRP analysis. To that point, AmerenUE offers $13 million to illustrate its commitment.

[119] Surrebuttal Testimony of Michael Moehn at 26:2-6.
[120] Surrebuttal Testimony of Michael Moehn at 26:14-16.
[121] Surrebuttal Testimony of Michael Moehn at 26: 16-19.
[122] Surrebuttal Testimony of Michael Moehn at 27:15-16.
[123] Surrebuttal Testimony of Michael Moehn at 28:16-20

9. Low Income Programs:

A. Should AmerenUE continue to fund its current low-income weatherization program? If so, how should the program be funded?

B. Should AmerenUE fund low income programs at minimum levels? If so, at what levels?

First, the Surrebuttal Testimony of Richard Mark set forth the Company's proposal to fund certain low-income programs, including Dollar More along with certain weatherization programs, as part of its request for Commission approval of an FAC. As part of its FAC proposal, the Company will contribute $2 million annually to Dollar More, a program that provides low-income customers with assistance in paying their utility bills, and in addition, the Company will contribute $1.2 million annually to low-income weatherization programs.[124] Consistent with the recommendations contained within the testimony of Staff witness Lena Mantle, half of that $1.2 million will be funded by shareholder contributions.[125]

10. Green Power: Should AmerenUE's Voluntary Green Power Program be approved?

As set forth in the testimony of AmerenUE witnesses Robert Mill and William Barbieri, the Company is proposing implementation of a Voluntary Green Program (VGP) tariff, which would provide customers the option of purchasing Renewable Energy Certificates (REC) to support the development of renewable energy.[126] This program is designed for customers who want to financially support the further development of renewable energy and is based on the purchase and retirement of RECs. To be clear, this program does not involve the actual delivery of a renewable energy commodity to the customer or to the AmerenUE system. Rather, the program bills customers who elect to participate an additional 1.50 cents per kWh for their total

[124] Surrebuttal Testimony of Richard Mark at 2:8-10; 3:7-9.
[125] Surrebuttal Testimony of Richard Mark at 3:10-11.
[126] Direct Testimony of Robert Mill at 13:19.

monthly usage. This money is used to purchase and retire RECs.[127] One REC is equivalent to 1,000 kWh of renewable energy[128]. It is estimated by the National Renewable Energy Laboratory, in conjunction with the U.S. Department of Energy, that voluntary programs, such the one proposed by AmerenUE, are directly responsible for adding over 2,000 MWs of additional renewable generation in the United States.

AmerenUE's program has been designed in a manner that provides a multitude of safeguards for the Company's customers. First, this program is completely optional for the Company's customers. Once a customer has signed up, they will be provided additional detailed, written information about how the program works. At any point, if participating customers decide to end their election to participate, they may do so at any time and without notice. There is no waiting period to cancel and customers are not obligated to any certain length of participation. AmerenUE has chosen an experienced company, 3 Phases Energy Services, to perform its customer education and for marketing the program, in addition to providing all RECs for the program. Finally, the program will be certified by Green-e, a nationally recognized organization. Green-e will provide verification and the audit process for this program. These multiple safeguards are designed to protect AmerenUE's customers who voluntarily participate.

Finally, AmerenUE would note that, unlike the process and time required with the development of a wind farm, once the Commission approves this tariff, it can be quickly implemented. There will be very little lead time required before customers of AmerenUE can begin their voluntary participation in the program. AmerenUE believes the Commission should approve the VGP tariff to allow interested customers an avenue to support the development of renewable resources.

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[127] Surrebuttal Testimony of William Barbieri at 2:22-23; 3:1-6.
[128] Surrebuttal Testimony of William Barbieri at 16:10-14.

11. ROE: What return on equity should be used in determining revenue requirement?

A. INTRODUCTION

AmerenUE has requested to be allowed a return on equity (ROE) of 12%. This figure was supported by testimony from two highly qualified experts, Ms. Kathleen C. McShane and Dr. James H. Vander Weide. The experts of the other parties in this matter have recommended returns on equity ranging from 9.0% to 9.8%.[129] These recommendations are simply too low given the electric industry's need for infrastructure investments and investors' return expectations. It is vital for the continued financial health of AmerenUE and for its ability to finance expected infrastructure expenditures that it be allowed an opportunity to earn a ROE that is consistent with investors' expectations.

The recommended ROEs now before the Commission are:[130]

Witness	Recommendation
McShane (Company)	12.0%
Vander Weide (Company)	12.2%
Gorman (MIEC)	9.8%
King (OPC)	9.65%
Hill (Staff)	9.25%
Woolridge (State)	9.0%

B. THE COMMISSION SHOULD ALLOW AN ROE AT THE HIGH END OF THE RANGE OF RECOMMENDED ROES BEFORE IT.

i. Allowed ROE in Other Cases and the Expectations of the Financial Markets Indicate that the Other Parties' Recommended ROEs Are Too Low.

In the recent past, the Missouri Public Service Commission (PSC) has granted Missouri utilities an allowed ROE of 10.9% to 11.25%[131] while the FERC's average allowed ROE was

[129] Rebuttal Testimony of Kathleen C. McShane at 7:5 (McShane Rebuttal).
[130] *See* Direct Testimony of Kathleen C. Mc Shane at 4:11-13 (McShane Direct); Direct Testimony of James H. Vander Weide, PhD. at 5:21 – 6:2 (Vander Weide Direct); and McShane Direct at 7:6.
[131] McShane Rebuttal at 20:10-11, Rebuttal Testimony of James H.Vander Weide, PhD. at 9:6-11 (Vander Weide Rebuttal).

above 12% in 2005-06[132] and thus in line with AmerenUE's requested ROE. Moreover the allowed rates of return for integrated utilities, which are considered of higher risk than wires only companies, have been well above those recommended by the other parties.[133] This regulatory track-record clearly indicates that the other parties' recommended ROE is too low.

At the same time, investors expect returns on equity in the 11.5% to 12% range. For example, Value Line expects the electric utility industry to earn an ROE in the range of 11%–11.5% going forward[134] while A.G. Edwards recently estimated the ROE for Ameren Corporation at 12% for 2007.[135] As AmerenUE witness David Svanda points out in his Surrebuttal Testimony, financial markets provide helpful insights for regulators into the range of ROEs that should be considered.[136] Certainly credit rating agencies pay close attention to financial markets' expectations regarding ROE, and often take negative action if the allowed ROE is perceived as being too low by those markets.[137]

ii. The Need to Make Infrastructure Investments and to Overcome the Increasing Risks of the Electric Industry Strongly Counsel the Choice of an ROE at the Higher End of the Range Before the Commission.

There is currently a significant need for infrastructure investment for generation, transmission, distribution, and environmental abatements in the electric industry.[138] As Ms. McShane noted, "The return on equity capital represent the compensation investors require to make available the funds necessary to build, grow and maintain the infrastructure necessary ..." and as the Commission has pointed out, .. "We can never have efficient service, unless there is a

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[132] Vander Weide Rebuttal at 9:15-16.
[133] McShane Rebuttal at 20; Surrebuttal Testimony of David A. Svanda at 10:20 – 11:6 (Svanda Surrebuttal).
[134] Vander Weide Rebuttal at 9:17 – 10:3.
[135] McShane Rebuttal at 30:19-21.
[136] Svanda Surrebuttal at 10-12.
[137] Svanda Surrebuttal at 11:7 - 12:2.
[138] Vander Weide Direct at 15:22 – 16:8; Direct Testimony of Warner A. Baxter at 8:21 – 9:6 (Baxter Direct).

reasonable guaranty of fair returns for capital invested.'"[139] Electric utilities, including AmerenUE, have increased capital expenditures in recent years and therefore have seen declining free cash flow. Therefore, to ensure that sufficient capital is available for AmerenUE's expected investment in infrastructure, its allowed ROE needs to be at the high end of the reasonable range.[140] And the Company recommended 12% is not an outlier.[141] FERC has clearly acknowledged the need for allowed rates of return in the high end of the zone of reasonableness to provide incentives for infrastructure investments.[142]

Electric utilities are also facing increasing risks from the significant rise in the cost and volatility of fuel and power,[143] from changing regulation and from ongoing globalization, which increases the cost of fuel and materials.[144] AmerenUE faces further risks from being a single nuclear asset utility and from its current lack of a fuel adjustment clause.[145] Note that because most of the utilities included in AmerenUE witnesses' proxy groups have a fuel adjustment clause, the Company witnesses' recommended ROE is based on the assumption that AmerenUE will have a fuel adjustment clause going forward.[146]

The allowed ROE and the level of a utility's rates are not necessarily in competition. There is a tie between financially healthy utilities, which is partly a function of their allowed ROE, and their ability to provide reliable service at low rates.[147] AmerenUE has some of the lowest electric rates in the country,[148] operates a reliable electric system, and has, given the

[139] McShane Direct at 5:5-10.
[140] Svanda Surrebuttal at 12:3-11, McShane Rebuttal at 7:19 – 8:11.
[141] Svanda Surrebuttal at 13:11-12.
[142] McShane Direct 13:2-7.
[143] Vander Weide Direct at 15:22 – 16:8.
[144] Svanda Surrebuttal at 8:21 – 10:13.
[145] McShane Direct at 5:8 – 6:2.
[146] McShane Rebuttal at 18:15-19, Vander Weide Direct at 43:15-22.
[147] Svanda Surrebuttal at 5:3 - 6:7.
[148] Surrebuttal Testimony of Warner A. Baxter, Schedule WLB-15 (Baxter Surrebuttal).

circumstances, done a good job during recent outages.[149] The magnitude of the allowed ROE is especially important given the concern of credit rating agencies over the declining free cash flow of electric utilities[150] and the generally more challenging environment facing AmerenUE.[151]

iii. The Methodology Underlying AmerenUE's Recommended ROE Is More Reliable Than That Underlying the Other Parties' ROE Recommendations.

All ROE witnesses in this proceeding, except Missouri Energy Group witness Billie S. LaConte who does not present cost of capital estimation results, select one or more sets of comparable companies and estimate the cost of equity using a version of the Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) methods. Nevertheless, there are four key differences separating the ROE testimony before the Commission in terms of how these methods are applied. (1) AmerenUE's witnesses recognize, as a matter of standard financial economics, that the cost of equity is measured in relation to market values and cannot be applied to the book value of equity, as the other witnesses do, without acknowledging the difference in financial risk. (2) The Company witnesses rely on several standard estimation methods and weigh the methods equally, while some of the other parties' witnesses favor one methodology, the DCF method. (3) Ms. McShane and Dr. Vander Weide rely on objective measures of the market risk premium for their CAPM model. Some of the other witnesses subjectively choose their market risk premium from studies that reflect a particular time period, or rely on measures that are inconsistent with the practice recommended in the financial literature. (4) Both Company witnesses rely on analysts' forecasted growth rates in their implementation of the DCF model, as the authoritative literature on this subject suggests is the superior approach, while some intervenor witnesses rely on historical and/or subjectively chosen growth rates.

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[149] Svanda Surrebuttal at 14:6 – 15:2, Surrebuttal Testimony of Ronald C. Zdellar at 6:22 – 7:4 (Zdellar Surrebuttal).
[150] Svanda Surrebuttal at 7:16-18.
[151] Baxter Direct at 7:18 – 9:14.

a. Acknowledging differences in financial risk.

AmerenUE's witnesses explain that the cost of capital for a company is a function of the company's total risk, including its business and financial risk. The business risk "is the forward-looking variability in the rate of return on an investment in the company's stock when the company is all-equity financed, and financial risk is the additional variability in the rate of return on an investment in the company's stock that arises as a result of debt financing."[152] The financial literature clearly documents that shareholders' risk increases with the firm's leverage, and that investors rely on market values in evaluating that risk.[153] While Staff witness Stephen G. Hill agrees that financial economists measure financial risk using market value,[154] he argues that there also is support for the use of book values in the literature. Ms. McShane and Dr. Vander Weide show that the literature relied upon by Mr. Hill simply does not support this claim.[155]

While all the other parties' witnesses object to any recognition of the differences in financial risk in estimating ROE,[156] the arguments on which they rely vary. However, all appear to suggest that the recognition of differences in financial risk leads to either ever-increasing earnings and stock prices, or to a return in excess of the cost of capital. This is simply not the case. Ms. McShane explains that if the utility is allowed to earn (and happens to earn) the return on equity that investors expect, then the investors' market return will equal the cost of equity and the market-to-book value remains unchanged.[157] As Dr. Vander Weide observes, the cost of

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[152] Vander Weide Surrebuttal at 5:3-8. *See also* McShane Surrebuttal at 4.
[153] McShane Surrebuttal at 8:20-23; Vander Weide Surrebuttal at 13:16-17.
[154] Rebuttal Testimony of Stephen G. Hill at 13:12-13 (Hill Rebuttal).
[155] Surrebuttal Testimony of Kathleen C. McShane at 9-10 (McShane Surrebuttal) and Vander Weide Surrebuttal at 13-15.
[156] Direct Testimony of Michael Gorman at 23-29 (Gorman Direct); La Conte Direct at 3-5; Hill Rebuttal at 2-28; Rebuttal Testimony of Charles W. King at 18-19 (King Rebuttal); Rebuttal Testimony of J. Randall Woolridge at 36-37 (Woolridge Rebuttal).
[157] McShane Rebuttal at 14:11 – 16:5.

equity for the proxy companies applies to companies with lower financial risk than is associated with the book-value capital structure of AmerenUE relied upon in this proceeding. Therefore, basic principles of financial theory inescapably lead to the conclusion that the cost of equity for AmerenUE is higher than that estimated for the sample companies.[158]

Reliance on market value capital structures has been accepted in several regulatory jurisdictions. For example, the Pennsylvania Public Utility Commission and this Commission have adopted a financial risk adjustment similar to the one recommended by Ms. McShane and Dr. Vander Weide. The Surface Transportation Board uses market value capital structures to estimate the cost of capital for railroads, and other regulatory bodies, including FCC's Wireline Competition Bureau, have used market value capital structures to estimate the cost of capital in cases involving telecommunications. Also, some state tax authorities use market value capital structure to calculate the cost of capital that is used to value the utilities for the purpose of assessing property taxes.[159]

Ms. McShane and Dr. Vander Weide take the capital structure that AmerenUE has used in its filing for granted, but acknowledge that the cost of equity is measured in the market place using a set of comparable companies. They are not, as Mr. Hill suggests, recommending the use of a market value capital structure percentage to calculate the overall cost of capital to be applied to AmerenUE's original cost rate base.[160]

Another criticism of recognizing the differences in financial risk comes from Mr. Hill and Office of the Public Counsel witness Charles W. King, who claim that it leads to circularity in regulatory process.[161] The circularity argument is completely based on these witnesses'

[158] Vander Weide Surrebutal at 11:20 – 12:5.
[159] McShane Direct at 41:2-8, Vander Weide Surrebuttal at 17.
[160] McShane Surrebuttal at 6:16 – 7:4, Vander Weide Surrebuttal at 10:17 – 11:5, Hill Rebuttal at 2.
[161] Hill Rebuttal at 6, Direct Testimony of Charles W. King at 9 (King Direct).

mistaken belief that Ms. McShane and Dr. Vander Weide rely on AmerenUE's market value capital structure.[162]

State of Missouri witness Dr. J. Randall Woolridge argues that the adjustment for financial leverage is unwarranted because market-to-book ratios above 1.0 indicate that utilities are earning more than their cost of capital.[163] However, this argument is refuted by the fact that there are many companies with market-to-book ratios above 1.0 that have negative earnings or rates of return well below those recommended by Dr. Woolridge.[164] Also, Mr. Hill argues that stock prices incorporate book value capital structure although clearly stock prices incorporate market as well as book value information.[165]

Taking the difference between the capital structure of the companies used in the estimation process and AmerenUE into account impacts the estimated cost of equity by 0.60%–1.30%.

b. No single or group test or technique is conclusive.

As noted by Ms. McShane, each test of the cost of equity for a proxy group has its strengths and weaknesses. Therefore, the Company witnesses rely on multiple tests to arrive at the recommended cost of equity.[166] The Commission has recognized this principle in the past.[167] In contrast, Mr. King, Mr. Hill, and Dr. Wooldridge argue that the DCF model is more "reliable" and weigh this model more heavily with Mr. King and Dr. Woolridge giving weight only to the

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[162] McShane Rebuttal at 16:6 – 17:2; Vander Weide Surrebuttal at 10:1-16.
[163] Woolridge Rebuttal at 36.
[164] Vander Weide Rebuttal at 61-64.
[165] Hill Rebuttal p. 4; McShane Surrebuttal at 11:1-9; Vander Weide Surrebuttal at 16:1 – 17:3.
[166] McShane Direct at 15:8 – 16:12.
[167] McShane Rebuttal at 17:18 – 18:4 citing *In the Matter of the Tariff Filing of the Empire District Electric Company to Implement a General Rate Increase for Retail Electric Service Provided to Customers in its Missouri Service Area*, Case No. ER-2004-0570 at 45 (issued March 10, 2005).

their DCF estimate.[168] As discussed by Ms. McShane and Dr. Vander Weide, the DCF model is currently not more reliable than other models due to the high variability in the results obtained from its implementation.[169]

c. The proper use of CAPM.

CAPM relies on three components to estimate ROE: the risk-free interest rate, the beta and the market risk premium. The risk-free rate is the expected rate of return on a risk-free government security, a company's beta measures of the company's risk relative to the market, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.[170]

Ms. McShane and Dr. Vander Weide both rely on a forecast of the risk-free rate, betas from Value Line, and two measures of the market risk premium. They rely on data from Ibbotson Associates to estimate the historical market risk premium using the methodology recommended by Ibbotson Associates, but also estimate a forward looking market risk premium using a DCF methodology.[171]

From the data in various publications they select (plus other analyses in Mr. Hill's case), Mr. Hill and Dr. Woolridge pick a number for their market risk premium. The data relied upon in the literature Mr. Hill and Dr. Woolridge selected includes the "bubble period" from mid- to late 1990, which is a period characterized as having unusual low market risk premiums that is not representative for purposes of estimating a going-forward figure.[172] Mr. Hill claims that regulators are "not aware of the significant new research regarding the market risk premium and

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[168] Direct Testimony of Stephen G. Hill at 35:12 – 36:7 (Hill Direct); King Direct at 19:21-25, 23:20-27; Woolridge Direct at 19:10-15.
[169] McShane Direct at 24-25; Vander Weide Direct at 25-26.
[170] Vander Weide Direct at 37.
[171] McShane Direct at 30-35; Vander Weide Direct at 29-37.
[172] McShane Rebuttal at 32-39, 50-51; Vander Weide Direct at 43-44, 59-61.

the reduction of long-term investor return expectations."[173] However, the research cited by Mr. Hill to support this claim is in fact not new, and offers no reason for the Commission to not use standard Ibbotson Associates data to estimate the market risk premium. Had Mr. Hill relied on the Ibbotson Associates data rather than his own judgment for the market risk premium, his estimated cost of equity would be about 1.6% to 1.9% higher for his electric and gas sample, respectively.[174] Similarly, Dr. Woolridge's relatively low CAPM results are largely driven by his reliance on a low market risk premium. Had Dr. Woolridge relied on the Ibbotson Associates market risk premium, his estimated cost of equity would have been approximately 2.5% higher.[175] Finally, Mr. King estimates his market risk premium using a DCF methodology.[176] As noted by Dr. Vander Weide, Mr. King's implementation of the model has several flaws that bias the cost of equity estimate downward.[177] Had Mr. King instead relied on standard Ibbotson Associates data for the market risk premium, his results would be substantially higher.[178]

Had these witnesses from the other parties relied on the standard market risk premium recommended by Ibbotson Associates, their CAPM results would have been significantly higher. As noted by Dr. Vander Weide and Ms. McShane, there is no evidence that there is a downward trend in actual achieved market risk premia that would support a lower forward-looking risk premium than what has historically been achieved.[179]

d. The use of analysts' forecasted growth rates in the DCF calculation.

The results from the DCF model hinge on the inputs used for the expected dividend yield (dividend over price) and the expected growth rate. While several varieties of the model have

[173] Hill Direct at 15:9:12.
[174] McShane Rebuttal at 39:10 - 40:2.
[175] McShane Rebuttal at 51:15-18.
[176] King Direct at 22.
[177] Vander Weide Rebuttal at 98-99.
[178] McShane Rebuttal at 72:1-6;Vander Weide Rebuttal at 100:1-11.
[179] McShane Rebuttal at 24-25, Vander Weide Direct at 35, Vander Weide Surrebuttal at 40.

been presented and the witnesses differ in their choice of inputs, the source of the largest discrepancies among the witnesses is the choice of growth rate. Ms. McShane and Dr. Vander Weide rely on analysts' forecasted growth rates, which are objective measures of investor expectations and generally superior to historically-oriented growth measures.[180] Mr. Hill and Dr. Woolridge note forecasted as well as historical growth rates on a number of parameters and then subjectively choose a number.[181] The subjectivity in Mr. Hill's and Dr. Woolridge's choice of a growth rate impacts the estimated cost of equity significantly. For example, Ms. McShane demonstrates that Mr. Hill's estimated cost of equity would have been approximately 1.25% higher had he relied on the forecasted growth rates he sets out rather than on his chosen growth rate.[182] Similarly, Dr. Woolridge picks growth rates that are lower than the projected growth rates and thereby biases downward the cost of equity estimates.[183] Mr. King weighs both analysts' growth forecasts and a GDP growth forecast for the economy in his version of the DCF model. However, the long-term growth rate for the economy lies below analysts' consensus forecasts for the proxy companies, and therefore biases the results downward.[184]

For all these reasons, AmerenUE believes that the 12% ROE recommended by Ms. McShane and Dr. Vander Weide is more appropriate than the unreasonably low ROEs recommended by the other parties, and should be adopted by the Commission in this case.

C. OPC WITNESS KING'S DOUBLE-LEVERAGE ADJUSTMENT TO AMERENUE'S CAPITAL STRUCTURE IS ENTIRELY INAPPROPRIATE.

OPC witness Charles W. King, alone among the rate of return witnesses testifying in this proceeding, is recommending an adjustment to AmerenUE's capital structure to reflect double

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[180] Vander Weide Direct at 20-21; McShane Rebuttal at 40-41; Vander Weide Rebuttal at 38-39.
[181] Hill Direct at Schedules 4-7; Direct Testimony of J. Randall Woolridge at Exhibit JRW-7; Vander Weide Rebuttal at 30:1-5.
[182] McShane Rebuttal at 42.
[183] Vander Weide Rebuttal at 53.
[184] McShane Rebuttal at 67:20-22.

leverage. The Company believes that this adjustment is completely unjustified and inappropriate. An adjustment for double leverage may only be appropriate where a parent company has used the proceeds from the issuance of its own debt to make an equity investment in a subsidiary. Since Ameren Corporation—the parent of AmerenUE—was formed in 1997, Ameren Corporation has never contributed to the equity capital of AmerenUE, so there is no double leverage in AmerenUE's capital structure. AmerenUE is capitalized independently of Ameren Corporation and its other affiliates, and so no double leverage adjustment is warranted. (Nickloy, rebuttal, p. 3.)

12. Pinckneyville and Kinmundy: What amount should be included in rate base for AmerenUE's purchase of these CTG plants?

It is the Company's position that the full cost of these CTGs should be reflected in rate base.

In 2002, the Commission approved a Stipulation and Agreement that resolved Case No. EC-2002-1. Part of AmerenUE's commitment under that Stipulation was to use commercially reasonable efforts to make energy infrastructure investments in excess of $2.25 billion over a five-year period. AmerenUE has met and indeed exceeded that commitment, which included a commitment to add 700 megawatts (MW) of new regulated generating capacity, which could "include the purchase of generation plant from an Ameren affiliate at net book value." (Stipulation and Agreement, Case No. EC-2002-1, p. 6) (S & A).

In 2005, AmerenUE closed on an acquisition of new regulated generating capacity – the Pinckneyville and Kinmundy (P & K) combustion turbine generators (CTGs) – from its affiliate, Ameren Energy Generating Company (AEG). The price paid was net book value, as contemplated by the S & A. The acquisition, which AmerenUE had intended to complete in 2003, had been delayed for two years due to attempts by NRG, which at the time owned CTGs located in Audrain County, Missouri, to prevent necessary Federal Energy Regulatory Commission (FERC) approval of the sale.[185]

The P & K issue exists because of a rate base adjustment proposed by Staff witness Stephen Rackers,[186] OPC witness Ryan Kind, and State witness Michael Brosch. They all in effect argue, just as NRG did (unsuccessfully) in the above-referenced FERC proceeding, that the price paid by AmerenUE (net book value) was more than the fair market value of these CTGs. They therefore assert that the purchase did not meet the pricing provisions of the Commission's Affiliate Transaction Rules, or that it was imprudent, justifying a rate base write-down. The effect of their proposed write down is to reduce the Company's revenue requirement by approximately $7 - 8 million, depending upon the rate of return determined in this proceeding.

NRG, in extensive FERC proceedings covering eight days of evidentiary hearings on just this one issue, already lost what was essentially this same argument. Indeed, NRG argued that its willingness to sell its Audrain CTG Plant at $391 per kilowatt (kw) versus the net book value transfer price of the P & K CTG Plants ($439.50/kw), proved that the price paid by AmerenUE for these CTGs was above-market and would, if allowed, harm competition and constitute affiliate abuse, within the meaning of Section 203 of the Federal Power Act.[187] All of these witnesses base their proposed adjustment on the contention that AmerenUE could have bought the same Audrain CTG Plant for less than the net book value of the Pinckneyville and Kinmundy CTG Plants, which they argue means that the net book value paid by AmerenUE was above-

[185] *See* FERC Docket No. EC03-53-000.
[186] Staff has informed the Company that Staff no longer supports making a rate base adjustment with respect to P & K. This means that only OPC and the State are proposing a rate base adjustment. Staff witness Rackers' testimony and admissions are, however, relevant to OPC's and the State's continued proposal of a rate base adjustment.
[187] Section 203 required approval for the transfer because these CTGs were FERC jurisdictional assets. *See* FERC Initial Decision, Docket No. EC03-53-000 (Feb. 5, 2004); FERC Order 473, 108 FERC ¶ 61,081, Docket No. EC03-53-000 (July 29, 2004).

market. In short, to prevail, they would have to convince this Commission that the FERC was wrong when it found that the sale did not harm competition or constitute affiliate abuse because the price paid by AmerenUE to AEG did not provide AEG with a "safety net" (i.e., that AmerenUE did not pay AEG an above-market price).

The FERC Administrative Law Judge (ALJ) who heard the case soundly rejected NRG's position, finding that NRG's expert's analysis, upon which NRG based its case, "was flawed and is accorded no weight here." Initial Decision, page 57, ¶ 126. The Initial Decision went on to state that "[NRG witness] Dr. Rudevich's revised asset valuation study demonstrates that the net book value of the Kinmundy and Pinckneyville plants is *at or below fair market value of the two units*." (emphasis added). Ultimately, the Initial Decision determined that AmerenUE's purchase of the P & K CTGs would have no adverse impact on competition, meaning that AmerenUE was paying a fair price and not in effect squeezing out competing non-affiliated buyers by subsidizing its affiliate, AEG. *Id.* at pages 1-2. In summarizing the Initial Decision, the ALJ found that "the purchase of the Pinckneyville and Kinmundy plants at net book value is *consistent with the results that would have been obtained through a competitive bidding process* reflecting interplay between AmerenUE and independent sellers, and has not resulted in undue preference being shown to AmerenUE's affiliate, AEG." *Id.* (emphasis added) In other words, had a competitive bidding price been used, the market would not have a set a price *lower* than that paid by AmerenUE.[188]

[188] As discussed at ¶ 4 of the Initial Decision, it is important to note that when AmerenUE was first seeking the capacity it needed (and that it ultimately obtained with the purchase of the Pinckneyville and Kinmundy CTGs), AmerenUE did conduct a competitive bidding process through an RFP sent to 50 companies. In the FERC proceeding, others argued that AmerenUE should have done a second RFP, a point rejected by the FERC, which found that such a process would not have produced a lower price than AmerenUE paid for the P & K CTGs. *See also* Initial Decision at ¶¶ 5, 28 n.70.

The FERC itself affirmed the Initial Decision in part,[189] and did not disturb any of the findings in the decision cited above. Ultimately, the FERC itself agreed that the transaction did not harm competition and that there was no affiliate abuse and that the transaction did not provide a safety net (i.e., did not result in payment of an above-market price) for AEG.

Has any other regulatory authority also addressed the appropriate valuation of CTG Plants during this time-frame? The answer is "yes"; *this Commission* did so in Case No. EO-2004-0108. In that case, *the* central issue was whether or not buying more gas-fired CTGs was a lower-cost option for serving Missouri retail load than transferring away the Company's former Metro East customers thereby in effect freeing-up additional baseload coal-fired generating capacity. Which option was the least-cost option turned on what costs AmerenUE would have to incur to acquire an appropriate mix of CTGs. Mr. Kind argued then, as he does now, that AmerenUE could acquire CTGs much cheaper than just about everyone else believes to be the case. In rejecting Mr. Kind's proposed CTG price in the Metro East case, the Commission stated (just a few months before the P & K CTGs were acquired by AmerenUE) as follows:

> The Commission does not agree with Public Counsel, however, that UE erred by pricing CTGs at $471/kW. Staff witness Proctor testified that UE's $471/kW figure was based on the average cost of a mix of larger, less expensive CTGs and smaller, more-flexible-but-more expensive CTGs. The record shows that such a mix of units is required in order to achieve the greatest possible operating flexibility and efficiency and that UE would build such a mix if the proposed transfer is not approved. For this reason, the Commission finds that the $471/kW figure used by UE was appropriate.[190]

So how did Mr. Rackers, before Staff agreed that an adjustment should *not* be made, and Mr. Kind reach their conclusion that the market value of these CTG plants was lower than their depreciated cost (i.e., their book value)? In a word: creatively. They both take a one and one-

[189] The FERC's only substantive disturbance of the Initial Decision related to the FERC's announcement that, prospectively, the FERC would apply different standards to transfers of generating assets between affiliates. FERC Order 473, 108 FERC ¶ 61,081, at ¶¶ 1-2.
[190] Report and Order on Rehearing, Case NO. EO-2004-0108, p. 24, (Feb. 10, 2005).

half page 2002 letter – a non-binding "indicative proposal" from an NRG staffer – and attempt to transform this non-binding, indefinite proposal into a contention that it set the market value of the P & K CTGs. They make this attempt despite the fact that those CTGs have far different operating characteristics than the Audrain CTGs and despite the fact that not only did NRG never "offer" to sell the Audrain CTGs at the price relied upon by Messrs. Rackers and Kind, the sworn testimony of NRG's President in charge of NRG's Audrain CTG Plant indicates that the price NRG would have offered was much higher than the price cited by Messrs. Rackers and Kind.[191] In short, this non-binding indicative proposal is meaningless and does not set a fair market value for any CTG, let alone the substantially different CTGs located at P & K.

An examination of the facts soundly refutes these contentions. On August 15, 2002, a lower-level staffer at NRG, named Connie Paoletti, [192] sent the indefinite, non-binding "indicative proposal" to the then Senior Vice President of Ameren Energy. That "indicative proposal," which was not an offer to sell, indicated that Ms. Paoletti expected a purchase price of $200 million, or approximately $346/kw.[193] For at least three reasons, that figure bears no resemblance to a fair market price for the P & K CTGs.

First, Ms. Paoletti's "indicative proposal" was not an offer, it was not binding, and, importantly, it reflected a *forced sale price* that is irrelevant to trying to determine a fair market value for the P & K CTGs. Second, it is not even the price NRG was actually willing to sell for – which indeed, according to NRG's President in sworn testimony, was much higher

[191] Direct Testimony of Ershel C. Redd, FERC Docket No. EC03-53-000, Aug. 8, 2003.
[192] The letter was signed by Connie L. Paoletti who apparently worked in "origination." As an example of what little those who proposed this rate base adjustment knew about this "indicative proposal," consider that fact that Mr. Rackers has no idea whoMs. Paoletti is, has never talked to her, and only "assumed" she had the authority necessary to negotiate a sale. Rackers Deposition, p. 36, l. 21 to p. 37, l. 1.
[193] As discussed in Mr. Voytas' Rebuttal Testimony (and as admitted by Mr. Rackers in his deposition), Mr. Rackers and Mr. Kind both used an incorrect and irrelevant "nameplate" rating for the NRG Audrain CTGs, rather than the Audrain CTGs actual output capability. That mistake alone reduces the rate base write down they advocate by more than $18 million.

($391/kw).[194] Third, the NRG Audrain CTGs and the P & K CTGs are quite dissimilar. Taken as a whole, the P & K CTGs have operating characteristics that make them worth much more in the market.

When Ms. Paoletti sent her "indicative proposal" letter, NRG was in financial distress, as testified to under oath by NRG's Chairman, President, and CEO, Mr. Ershel C. Redd, Jr. As Mr. Redd explained, "it is well known that during the last year or so, NRG's financial condition has significantly deteriorated . . . in 2002, NRG entered into discussions with its creditors in anticipation of a comprehensive restructuring of its business." Ms. Paoletti's indicative proposal letter was sent in August 2002, just one year before Mr. Redd so testified, and just nine months before NRG filed bankruptcy. Why does NRG's financial distress matter? Because it is obvious that the sale of an asset under conditions when the seller is facing bankruptcy would be a forced sale made at below-market prices, not a fair market price sale. It is well accepted that a fair market price is a price that a willing seller would sell something for being under no compulsion to sell it and that a willing buyer would pay for something being under no compulsion to buy it.[195] Mr. Rackers agrees that this is what fair market price means. Rackers Deposition, p. 36, l. 2-13.[196] But a financially distressed seller *is* under a compulsion to sell, and it's a simple matter of common sense that a financially distressed seller will likely sell assets for less than a fair market price. Mr. Rackers agreed. Rackers Deposition, p. 36, l. 23 to p. 37, l. 14; p. 43, l. 20 to

[194] Incredibly, although Mr. Rackers purported to have reviewed FERC filings relating to the P & K CTGs (Rackers Direct Testimony, p. 12, l. 19-20), he did not know who Mr. Redd was nor did he review Mr. Redd's testimony. Rackers Deposition P. 46, l. 20 to p. 47, l. 13. Instead, he seemed to selectively point to information that supported his conclusions, while ignoring any fact that was contrary to those conclusions.

[195] *Cf.* Missouri Approved Instruction 16.02.

[196] "Q. Would you agree, Mr. Rackers, that a fair market price is a price that a willing seller would sell something for being under no compulsion to sell it and that a willing buyer would pay for something being under no compulsion to buy it? A. That's a definition of what did you say again? Q. Fair market price. A. I'll accept that. Q. You'd agree that's a fair definition of fair market price" A. Yes."

p. 44, l. 5; p. 45, l. 1 – 21.[197] However, Mr. Rackers didn't even know NRG was in financial distress, and never considered that highly relevant and important fact.[198] In short, Mr. Rackers initially took (but now has properly thought better of it) and Mr. Kind also took a non-binding "indicative proposal" from what appears to be a low-level NRG employee, sent at a time when NRG was embarking on a fire sale of its assets to satisfy its creditors, and based upon this meaningless one and one-half page letter, attempt to establish that the market value of the completely dissimilar and more valuable P & K CTGs was lower than the book value paid for them by AmerenUE. Reliance on this "indicative proposal" is entitled to no weight whatsoever, and is indeed spurious.

Not only does Mr. Redd's sworn testimony show that the price mentioned in Ms. Paoletti's letter was a forced sale price, but his testimony indicates the price recited by Ms. Paoletti was wrong. Redd cites a much higher price (up to $391/kw, which is just $47.50 less than the price AmerenUE paid for the P & K CTGs).[199] But even that figure is understated. Mr. Redd assumed that the NRG Audrain CTGs had a capacity of 640,000 kw[200] when in fact their net summer capability (which is how Messrs. Rackers and Kind priced the Pinckneyville and Kinmundy CTGs) was much lower – just 600,000 kw.[201] Moreover, according to the MISO, *today* the actual outlet capability of the NRG Audrain CTGs is just 578,000 kw.[202] Applying either of the more correct capacity figures to the NRG Audrain CTGs means that Mr. Redd and

[197] "Q. All right. And just as an example, if I'm a seller, I've got some compulsion that means I've got to, for whatever reason, sell this now, I may be in a weak position as, vis-à-vis, the buyer be in a weak bargaining position, and I may not be able to demand a fair price because I've got some compulsion driving me to sell it now at a cheaper price. Doesn't that happen? A. I'm sure it happens."

[198] Rackers Deposition P. 42, l. 16-22 ("Q. Were you aware that NRG's financial condition was deteriorating and that NRG was in discussion with creditors about debt restructuring about the same time this indicative offer – this indicative proposal was sent to AEG; were you aware of that? A. No.").

[199] Redd Direct Testimony, p. 8, l. 177-179.

[200] Redd Direct Testimony, p. 5, l. 109-111.

[201] Rebuttal Testimony of Richard A. Voytas, p. 7, l. 12-16.

[202] Rebuttal Testimony of Richard A. Voytas, p. 18, l. 25-29.

NRG actually believed the fair market price of the NRG Audrain CTGs was either $417/kw (at its net summer capability) or $434/kw (at its actual outlet capability).[203] Both prices are in the general range of the price actually paid by AmerenUE for the Pinckneyville and Kinmundy CTGs.[204] And, as discussed further below, a dollar-to-dollar comparison of one CTG plant to another is meaningless unless one considers the particular characteristics of each plant which in turn *drive the value* of a particular plant. The P & K CTG Plants, with superior operating characteristics, are simply worth more than the Audrain Plant.

At bottom, if for argument's sake one were to rely upon NRG's view of the value of the Audrain CTGs (which is precisely what is occurring when these witnesses rely upon Ms. Paoletti's indicative proposal), then one has to conclude that AmerenUE paid a price quite close to that value for the much different and indeed superior P & K CTGs.[205] And, keep in mind, that the $417/kw or $434/kw price supported by NRG's President Mr. Redd was still a distressed price being discussed during a time when NRG was in bankruptcy rather than a fair market price for those units.

The fact is that no one should be relying on any price for the NRG Audrain CTGs in trying to determine a fair price for the P & K CTGs because the two CTG plants are quite dissimilar – indeed, it's like comparing apples and oranges. The NRG Audrain CTGs are large

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[203] Mr. Rackers, consistent with his total failure to analyze the similarities or differences between the Audrain CTGs and the P & K CTGs, made the totally mistaken assumption that the Audrain CTGs had transmission outlet capability. On what did he base this? The same, indicative proposal from Ms. Paoletti. Of course, Mr. Rackers was wrong. Rebuttal Testimony of Richard A. Voytas, p. 15, l. 15 to p. 19, l. 4.

[204] And it is noteworthy that at the time of the FERC proceeding, the transmission outlet capability was essentially zero, and indeed, the NRG CTGs had never been run commercially at all.

[205] Mr. Kind also uses the after-the-fact acquisitions by AmerenUE of two CTG plants from Aquila and the ultimate purchase of the Audrain CTG Plant, the sales for which closed in March 2006, to second-guess AmerenUE's purchase of the P & K CTGs. In other words, Mr. Kind apparently seeks to punish AmerenUE for waiting to buy these additional CTGs until AmerenUE needed more capacity, and at very favorable, forced-sale prices, at a time when the CTG market in the region had substantially deteriorated, in part because both NRG and Aquila's financial straits were clearly quite poor. Mr. Kind's position brings to mind the cliché "no good deed goes unpunished. In any event, the NRG and Aquila plants are not comparable to the P & K CTGs, and were bought at a different time under different circumstances.

frame CTGs[206] without quick start capabilities (thus they do not count toward operating reserves), without intraday cycling capability, with higher heat rates (i.e., they are less efficient), and with higher start-up and operating and maintenance costs. Consequently, they are dispatched less frequently.[207] In short, they are worth far less. The combined Pinckneyville and Kinmundy CTGs consist of two large frame units, but also four aero-derivative units, and four small frame units. Overall, these units have features (dual-fuel capability at Kinmundy, much better heat rates, quick start capability, intraday cycling capability for many of the Pinckneyville units) that make them worth far more than the NRG Audrain CTGs. There is no evidence that these witnesses know anything about any of this, or that they performed any analysis to account for the drastic differences between these plants.[208]

Although Staff no longer proposes a rate base or other revenue requirement adjustment relating to P & K, it is noteworthy that when Staff first proposed their now-withdrawn adjustment, Mr. Rackers was also incorrect in arguing that AmerenUE could have built comparable CTG plants for less than the net book value paid for the P & K Plants. In making this argument, Mr. Rackers relied upon the cost of CTG installations at the Company's Venice Plant site.[209] But Mr. Rackers mis-valued the cost of the Venice CTGs and ignored key factors that reduced the construction costs at Venice, as discussed below. First, the weighted average cost of the Venice CTGs was $378/kw, not $337, as Mr. Rackers incorrectly stated.[210]

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[206] *See, e.g.* Mr. Racker's deposition, where he claimed that the NRG CTGs were *not* large frame units. Rackers Deposition, p. 66, l. 5-9. In fact, he didn't even understand that an aero-derivative unit has a much higher value than a large frame unit. Rackers Deposition, p. 67, l. 15-21.
[207] Voytas Rebuttal Testimony, p. 7, l. 17 to p. 10, l. 8.
[208] "Q. You haven't done any analysis to determine whether or not whatever cushion you think might exist [in the NRG indicative proposal] is more than offset by differences in operating or plant characteristics, have you? A. I have not done that." Rackers Deposition p. 87, l. 4-8.
[209] Rackers Deposition, p. 26, l. 13-22.
[210] Voytas Rebuttal p. 11, l. 5-8.

Second, Mr. Rackers ignored (indeed, he was unaware because he conducted no analyses and even failed to make any attempt to analyze the comparability, or lack thereof, of any of the various plants he considered) the fact that the Venice CTGs were installed at an existing plant site that already had substantial infrastructure in place that simply would not exist in the normal case where a CTG plant has to be built.[211] The latter point is driven home by Mr. Rackers' apparently conscious decision to ignore the construction cost of an AmerenUE CTG plant constructed in the same general time-frame at issue in this case, the Company's Peno Creek CTG Plant. Staff has audited the Peno Creek CTG construction and, as Mr. Rackers' colleague staff witness Leon Bender testified, Staff found no costs at Peno Creek (or at Venice) that should not be allowed in rate base. The cost to construct Peno Creek was $570/kw, far more than the Company paid for the Pinckneyville and Kinmundy CTGs.[212]

The bottom line is that those who propose a rate base adjustment have engaged in a narrow picking and choosing exercise where they place reliance on a non-binding indicative proposal from a distressed seller at a price that same distressed seller's president indicated is lower than they expected to sell the units for, and they rely on an incorrectly calculated price for newly constructed units, while ignoring other more comparable units, to erect a construct of so-called "facts" to support their proposed rate base adjustment.

Mr. Kind's arguments are essentially identical to the ones Mr. Rackers formerly made, and he too ignores relevant information and makes the same mistakes as Mr. Rackers. Mr. Kind

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[211] Voytas Rebuttal, p. 11, l. 9 to p. 14, l. 7.

[212] Not all of the CTGs at Pinckneyville and Kinmundy are aero-derivative units, like those installed at Peno Creek, so it makes sense that the Peno Creek CTGs cost more to install than the value of the Pinckneyville and Kinmundy CTGs. Pinckneyville and Kinmundy do include, however, four aero-derivative and four small frame units, both of which have a much higher cost than the large frame units at, e.g., Audrain. The Venice units are also a mix of CTG-types and, as noted, their installed cost was approximately 85% of the price paid for Pinckneyville and Kinmundy, yet as noted, there were substantial construction cost savings at Venice due to the existing infrastructure that was already in place there.

also second-guesses Staff's construction experts, like Mr. Bender, in advocating his separate rate base write-down for the Peno Creek Plant.

Mr. Brosch attempts to take a slightly different tack (in apparent recognition of the fallacy of relying on Ms. Paoletti's indicative proposal), but his arguments boil down to the same thing: a contention that AmerenUE paid more than a fair value for the P & K CTGs, which as noted above is contrary to FERC's conclusion on this very same issue. Mr. Brosch also mistakenly asserts that it is AmerenUE's burden to somehow justify the price it paid.[213] Indeed, the prior Stipulation and the other facts cited above, together with FERC's conclusion, provide ample justification. Under these circumstances, it is incumbent on Mr. Brosch to carry the burden of proving his assertion that the price paid was imprudent. The Commission, in reviewing prudence, presumes that the costs were prudently incurred and does not use hindsight to later second-guess the decision management has made.[214] The Commission is not the financial manager of the utility, and can only ignore an expense if the utility abused its discretion in making its decision.[215] The decision to add these generating assets – hard assets in AmerenUE's regulated rate base, as clearly desired by the Commission and as contemplated by the S & A, was made in 2002, subject to regulatory approvals that due to NRG's protest at FERC, took longer than expected. Every transaction Mr. Brosch relies upon took place after the decision was made.

At bottom, these witnesses ignore the fact that the FERC already found that the price paid by AmerenUE was similar to the price that would have been generated by a competitive bidding process (which by its very nature yields a market price), that there was no harm to competition, and that there was no affiliate abuse (i.e., that AmerenUE did not subsidize or provide a safety

[213] Brosch Direct Testimony, p. 54, l. 29 to p. 55, 1-5.
[214] *See, e.g., State ex rel. Assoc. Nat'l Gas v. Pub. Serv. Comm'n*, 954 S.W.2d 520, 528 (Mo. App., W.D. 1997).
[215] *See, e.g., State ex rel. GTE v. Pub. Serv. Comm'n,* 537 S.W.2d 655 (Mo. App., W.D. 1976).

net for AEG). These witnesses ignore that just a few months before the P & K acquisition closed, *this Commission* found that AmerenUE needed a mix of CTGs with an acquisition cost of $471/kw – more than $30/kw *more* than paid for the P & K CTGs. AmerenUE paid a fair price for these CTGs as was contemplated by the Case No. EC-2002-1 Stipulation, and the entire price paid should be included in AmerenUE's rate base in this case.

13. Peno Creek: What amount should be included in rate base for AmerenUE's construction of this CTG plant?

It is the Company's position that the actual cost of construction of this CTG Plant should be included in rate base.

This issue involves another CTG-related relating to a proposed adjustment to the rate base value of the Company's Peno Creek CTGs, proposed by Mr. Kind alone, which has a revenue requirement impact of approximately $3 million. Indeed, as is now the case with the P & K CTGs, Mr. Kind's position is not only contrary to the Company's position, but is directly contradicted by Staff's testimony in this case. Not only is it directly contradicted by Staff's testimony in this case, but it is directly contradicted by this Commission's Metro East case Order, cited above. Why? Because Mr. Kind argues that the Commission should assume that a fair value for the Peno Creek CTGs is just $390/kw, *just as he argued in the Metro East* case, despite the fact that this Commission *already rejected his $390/kw figure once*, as the quote from the Metro East Order set forth above demonstrates.

As noted, Staff disagrees with Mr. Kind in its testimony in this case as well. Mr. Bender, a Professional Engineer who has been working the power generation industry since 1978 (and has been on the Staff since 1995), audited AmerenUE's construction of the Peno Creek CTG Plant. His conclusion: "Q. Has Staff identified any concerns with the construction costs of the generating units discussed previously in this direct testimony [which included Peno Creek]? A.

Staff has not identified any construction costs during construction that should not be allowed in rate base."[216] That construction cost was $570/kw, for the eight aero-derivative units[217] installed at Peno Creek, and the entire sum should be allowed in rate base, as Staff recommends.

14. Metro East: Should any adjustment to AmerenUE's revenue requirement be made for any alleged non-compliance with the conditions contained in the Commission's order approving the Metro East Transfer and if so, what should the adjustment be?

In Case No. EO-2004-0108, the Commission's Order provided as follows:

> That AmerenUE may seek recovery in a future rate proceeding (a rate increase or an excess earnings complaint) of up to 6% of the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory, if it proves by a preponderance of the evidence that the sum of the Missouri ratepayer benefits attributable to the transfer in the applicable test year is greater than the 6% of such unknown generation-related liabilities sought to be recovered. AmerenUE will be entitled to recover that part of the 6% that is offset by benefits directly flowing from the transfer. Transfer-related benefits in this Paragraph and Ordered Paragraph 5 may only be used once (that is, the same dollar amount of transfer-related benefit cannot be used to offset unknown generation-related liabilities sought to be recovered pursuant to this Paragraph and to offset revenues imputed pursuant to Ordered Paragraph 5).

In this case, a very small sum, $138,303, which represents 6% of unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's former Metro East service territory, is included in AmerenUE's calculation of its revenue requirement. AmerenUE witness Gary Weiss outlines this small sum in his Rebuttal Testimony, including in Schedule GSW-E40 thereto.

The question then is, has the Company shown that there are benefits from the transfer totaling $138,30**4** or more? As Mr. Weiss explains, AmerenUE's net fuel costs in the test year were $22.3 million less by virtue of now having access to an additional 6% "slice" of AmerenUE's low-cost coal-fired generation than the fuel costs would have been had that 6%

[216] Mr. Bender's Direct Testimony, p. 5, l. 1-5.
[217] Recall that aero-derivative units are the most expensive units due to their favorable operating characteristics, as discussed in Mr. Voytas's Rebuttal Testimony.

slice still been serving the Metro East load. Insofar as it is obvious that $22.3 million far exceeds $138,303, AmerenUE's burden has been met.

The Commission's Order in Case No. EO-2004-0108 also provided as follows:

> That Union Electric Company, doing business as AmerenUE, as a condition of the approval herein contained, shall not recover in rates any portion of any increased costs due solely to transmission charges for the use of the transmission facilities herein transferred to AmerenCIPS to the extent that the costs in question would not have been incurred had the facilities not been transferred.

As Mr. Weiss's Rebuttal Testimony states, unequivocally, AmerenUE has included no such costs in its revenue requirement in this case. OPC asked Data Requests on this issue as well. Ms. Maureen Borkowski, Vice-President of Transmission, confirmed that there have been no such increased costs. In short, AmerenUE has included no such costs in its revenue requirement, and consequently, there simply is no issue relating to the quoted portion of the Commission's Metro East Order appearing immediately above.

15. **SO_2 *Allowances/* SO_2 *Premiums/2006 Storm Costs:***

A. Should revenues received from environmental allowance transactions be included in the revenue requirement and if so, what amount?

B. Should the Company establish a regulatory liability to account for sales of environmental allowances sold by the Company?

C. Should SO_2 premiums (net of discounts) be included in the regulatory liability account?

D. Should the balance of SO_2 allowances less SO_2 Premiums paid be used to offset 2006 storm costs? If so, what is the proper storm cost level to include in the cost of service?

i. Background.

The treatment of Sulfur Dioxide (SO2) emissions allowance margins is an issue in which several of the parties to this case have expressed widely divergent views. In addition, some parties' positions on this issue (including the Company's) have evolved as this proceeding has unfolded. A brief recap of the evolution of each party's position is necessary to provide the Commission with an understanding of the various parties' current positions on this issue.

In the Company's initial filing, we included in the calculation of our revenue requirement the actual amount of SO2 emission allowance margins[218] received during the test year—approximately $3.9 million. In their direct testimony, the Staff, OPC and the AG all proposed different approaches for treating these margins. Staff witness John Cassidy proposed inclusion of the test year margins and all subsequent margins in a regulatory liability account that would be used to offset the cost of emissions control equipment. Mr. Cassidy testified that this treatment was similar to the treatment of SO2 margins that the Commission had ordered for The Empire District Electric Company and Kansas City Power & Light Company. (Cassidy, direct, pp. 25-26.)

Public Counsel witness Ryan Kind argued that a "normalized" level of emissions allowance margins, equal to a 5-year average, should be imputed to the Company and included in the calculation of the Company's revenue requirement. For the 5 years ended June 30, 2006, Mr. Kind calculated this amount to be approximately $16.2 million. (Kind, direct, p. 18.) AG witness Michael Brosch argued that the allowance margins should be used to mitigate the sulfur component in the Company's coal costs. He recommended that a 4-year average of emission allowance costs, or $20.6 million, be included in the Company's revenue requirement, and if the Commission adopts a fuel adjustment clause for the Company, emission allowance margins above and below that amount should be tracked. (Brosch, direct, pp. 38-39.)

In rebuttal testimony, Company witness Warner Baxter recommended that approximately $32 million in emission allowance margins that the Company received between the end of the

[218] Since the SO2 allowances sold during the test year had a cost basis of zero, SO2 allowance margins was equal to SO2 allowance revenues. Some parties have referred to these amounts as SO2 allowance revenues.

test year (June 30, 2006) and the end of the update period (January 1, 2007) for this case be used to offset approximately $34 million in incremental operations and maintenance (O&M) costs incurred by the Company during that period related to the July and November/December, 2006 storms.[219] Mr. Baxter further supported the Staff's recommendation to establish a regulatory liability account on a going-forward basis to capture future SO2 allowance margins, and use these amounts to offset the capital costs of emissions equipment. Given this revised recommendation, Mr. Baxter recommended that no amount of emission allowance margins should be included in the calculation of the Company's revenue requirement. (Baxter, rebuttal, pp. 10-15.)

In his rebuttal testimony, OPC witness Kind made a number of adjustments to his level of "normalized" SO2 allowance margins, increasing the total amount of revenues he wishes to impute to $25.6 million. To accomplish this, Mr. Kind rolled forward the 5-year period over which he proposed to calculate the average of emissions margins to the period ending December 31, 2006. In addition he made two adjustments, one for $7.4 million in an attempt to account for a transaction occurring in December, 2006, and a second of approximately $19.5 million to reflect Mr. Kind's belief that a series of emission allowance sales occurring in December, 2005 were at prices far below the market price for allowances prevailing at that time. (Kind, rebuttal, p. 10.)

In surrebuttal testimony Company witness James Moore II addressed Mr. Kind's adjustments. With regard to Mr. Kind's first adjustment, Mr. Moore pointed out that Mr. Kind was erroneously double counting emissions allowance sales in December, 2006 because redundant trade tickets were issued for those sales. With regard to the December, 2005 sales,

[219] If SO2 allowance margins are not used to offset post-test year 2006 storm costs, Mr. Baxter recommended that these storm costs be treated as a regulatory asset and amortized over four years.

Mr. Moore testified that these sales were the result of the exercise of options to purchase emissions allowances AmerenUE sold to other parties in 2001 at strike prices negotiated at the time. As a consequence, even though the strike prices for those allowances were at a level far below the market price for allowances turned out to be in December, 2005, they were reasonable, market based prices in 2001, at the time the options were negotiated and the strike price was established. (Moore, surrebuttal, pp. 5-7.) However, Mr. Moore acknowleged that the premium AmerenUE paid to compensate the counterparties to exercise their options early—$834,919—benefitted shareholders and should not be recovered from AmerenUE customers. (Moore, surrebuttal, p. 7.)

In his surrebuttal testimony, Mr. Kind once again revised his “normalized” level of allowance margins, this time reducing the level to approximately $24 million. (Kind, surrebuttal, p. 17.) For its part, in surrebuttal testimony Staff developed a revised proposal, recommending that SO2 allowance revenues for the period from July 1, 2005 through January 1, 2007 (the test year and update period) be used first to offset net sulfur premiums that were part of the Company’s coal costs over the same period. The remaining balance of allowance margins, approximately $20.4 million, would then be used to offset the July and November/December 2006 storm O&M costs of approximately $34 million. The remaining balance of storm O&M costs ($13.6 million) would then be amortized over a five-year period. (Cassidy, surrebuttal, p. 12; Meyer, surrebuttal, pp. 2-4.)

ii. A “Normalized” Level of SO2 Allowance Margins Should Not Be Imputed in Calculating AmerenUE’s Revenue Requirement.

There are a number of reasons that it would be inappropriate for the Commission to establish a “normalized” level of SO2 emissions allowance revenues to be imputed in calculating AmerenUE’s revenue requirement, particularly at the very high $20-$25 million per year levels that OPC witness Kind and AG witness Brosch are recommending. First of all, the amount of allowance margins that AmerenUE realizes each year varies widely based on, among many other factors, market prices for allowances, and the need to retain allowances perceived by AmerenUE and other utilities to meet existing and potential future environmental requirements. The degree of variation can be seen simply based on the numbers reflected in testimony in this case—AmerenUE realized only $3.9 million in allowance margins during the test year, the Company realized an average of $20 to $25 million over the last 4-5 years, and it realized over $30 million in only a few months in the last part of 2006.

In addition, historic emission allowance margin realizations provide little or no guidance as to what level of margins the Company can be expected to realize in the future. This is not an item like revenues from jurisdictional customers or payroll, where the future level can be reasonably anticipated based on past experience. Moreover, the consequences of "getting it wrong" will mean that the Company either experiences undeserved windfall earnings or losses, an inappropriate reward or punishment for the Company's management of this important asset.

Even worse, inclusion of an amount of allowance margins in the revenue requirement calculation will provide an improper incentive for the Company to sell enough allowances to realize that amount of margins necessary for it to have a chance of achieving its authorized return. This may be inconsistent with the Company's proper management of the allowance bank to meet environmental requirements. Moreover, as Mr. Moore has testified, if other market participants realize that an assumed level of emissions allowance margins has been built into AmerenUE's revenue requirement, they will be in a position to take advantage of that knowledge in negotiating transactions with the Company. (Moore, surrebuttal, p. 2.) Finally, as Mr. Baxter has testified, inclusion of a normalized level of allowance margins would lead to unnecessary fluctuations in rates. (Baxter, rebuttal, p. 15.)

For all of these reasons, the Commission should not adopt any normalized level of emission allowance sales revenues for this case.

iii. The Company's Proposal to Offset Post-Test Year Storm O&M Costs With Allowance Margins Should Be Adopted.

The question then remains, how should these margins be treated to ensure that the customers get the benefit of any margins that may be realized, but the Company also has the flexibility to manage its allowance bank appropriately? First, the Company believes that the large amount of margins (approximately $32 million) that it realized in the few months between the end of the test year (June 30, 2006) and the end of the update period for this case (January 1, 2007) should be used to offset the even larger amount of O&M costs that the Company incurred in responding to the devastating storms of July and November/December 2006. As the Commission has recognized in other contexts, the costs of responding to unusual storms are considered to be non-recurring expenses that are not appropriate for inclusion in the calculation of a utility's revenue requirement, but instead are typically recovered from customers through a multi-year amortization. Similarly, the large amount of margins realized by the Company through the sale of emissions allowances is a non-recurring addition of revenues that can be used to offset the storm costs. AmerenUE believes that the best use of these revenues would be to offset the storm O&M costs, thereby insulating customers from a significant portion of the storm costs. We believe that this is a common sense approach to addressing non-recurring expense and revenue items that almost exactly offset each other and that it should be adopted by the Commission.

iv. The Company's Proposal to Account for Future Allowance Margins in a Regulatory Liability Account Should Be Adopted.

With regard to future allowance margins, the Company believes that a regulatory tracking mechanism must be adopted, to ensure that customers receive the benefit of all future margins, but also to ensure that the Company does not have any incentive to sell allowances just to meet an arbitrary revenue target. To achieve this result, the Company recommends that the Commission establish a regulatory liability to account for the emission allowance margins. The balance in the account would be used to offset the considerable capital cost of emissions equipment that the Company will be required to purchase and install over the next several years. This will provide the additional benefit of mitigating the impact of these necessary investments on customers, and it should be adopted. Establishment of a regulatory liability account is also consistent with the similar accounting treatment that the Commission has adopted for SO2 allowance margins of The Empire District Electric Company (Case No. EO-2005-0263) and Kansas City Power & Light Company (Case No. EO-2005-0329).

v. If the Commission Rejects the Company's Proposals for Addressing Emission Allowance Margins, Staff's Proposal Should Be Adopted.

If the Commission declines to adopt the Company's proposal for addressing emission allowance margins, the Company recommends that it adopt the Staff's proposed approach, as set forth in the surrebuttal testimony of Mr. Cassidy and Staff witness Greg Meyer. Staff's proposal provides many of the same benefits as the Company's proposal. First, it ensures that every dollar of SO2 emissions allowance margins will be used to offset costs for customers. Second, through the use of a tracking account the Staff's proposal ensures that the Company will not have any incentive to meet a target for allowance sales margins unrelated to proper management of the allowance bank. The Company is strongly opposed to the adoption of arbitrary, and unreasonably high "normalized" levels of margins, as recommended by Messrs. Kind and Brosch.

vi. The Company has done an Excellent Job of Managing its Emissions Allowance Bank.

Finally, it is important to point out that the evidence in this case shows that AmerenUE has done a superior job of managing its SO2 allowance inventory in more than a decade since the federal government adopted the allowance program. During the period from 2000 through 2005, through its allowance management activities, the Company added 225,144 allowances to its inventory by swapping excess banked allowances into future vintages at attractive swap ratios. These additional allowances have a current market value of approximately $93 million, which will ultimately redound to the benefit of AmerenUE's customers. (Moore, surrebuttal, p. 9.) The Company has also been able to reduce rates for its customers based on margins it has received from allowance sales, and still position itself, with a large allowance bank, to proceed deliberately in installing pollution control equipment. The Company's large allowance bank will enable it to learn from the utilities that are required to install pollution control equipment first, and benefit from any efficiency improvements and cost reductions that occur in the future. (Moore, surrebuttal, p. 9.) The Monday-morning quarterback criticisms of Mr. Kind regarding some individual transactions, which are for the most part inaccurate or distorted, should be rejected in the context of the Company's overall excellent performance in this area.

16. Depreciation Issues:

Although the Company, the Staff and the other parties have reached agreement on the appropriate depreciation rates for a number of accounts, there is still disagreement over several depreciation policy issues, which are addressed in this section of the brief. AmerenUE's position on these policy issues is presented in the testimony of William M. Stout. Mr. Stout is the

President of the Valuation and Rate Division of Gannett Fleming, Inc., the Company that produces the depreciation software used by both the Company and the Staff in their development of depreciation rates in this and other cases. Mr. Stout is one of the most well-known and well-respected depreciation professionals in the country, and has instructed programs in depreciation, including those attended by numerous Staff members, for the past 33 years. The Company's actual depreciation study and its recommended depreciation rates are sponsored in the testimony of John Wiedmayer, a depreciation engineer also employed by Gannett Fleming, who has provided depreciation studies in numerous jurisdictions, and who conducted the depreciation study the Company submitted in its last rate case. We believe that the testimony of these experienced depreciation witnesses provides the Commission with the appropriate guidance necessary to resolve the depreciation issues remaining in this case, consistent with mainstream depreciation approaches utilized throughout the country.

A. The Life Span Approach is Appropriate for Power Plant Service Lives.

The first depreciation policy issue the Commission is called upon to address is whether AmerenUE's power plants should be treated as "life span" property for purposes of calculating the depreciation rates for the components of the plants. Treating the plants as "life span" property simply means that the Commission recognizes the undeniable fact that the plants will not last forever and eventually will have to be retired, and at the point in time when the plant is retired, all of its components—boilers, turbines, transformers, etc.—will also be simultaneously retired. Use of the life span approach means that the survivor curves (showing the percentage of each plant account surviving at each year of service life) for each component of a power plant will be truncated at the point in time that the whole plant is estimated to be retired. Depreciation rates calculated using these truncated survivor curves will be somewhat higher, reflecting the reality that an individual plant component cannot continue in service past the date of the retirement of the power plant itself.

Mr. Stout has testified that recognition that power plants are “life span” property is the mainstream approach to depreciation of power plant components throughout the U.S., and that most, if not all state commissions follow this approach. (Stout, rebuttal, p. 8.) In addition, Mr. Stout has cited authoritative texts on depreciation that support the use of the life span approach for electric plants, including the NARUC manual on Public Utility Depreciation Practices, and Depreciation Systems by Frank K. Wolf and Chester Fitch, arguably the most widely cited text on this subject. (Stout, direct, p. 9.)

Notwithstanding the virtually universal acceptance of the life span approach for the depreciation of power plant components, the Staff is proposing to reject that approach, and effectively presume for purposes of calculating depreciation rates that AmerenUE’s power plants have an ***infinite*** life.[220] The Staff justifies its approach on the ground that the Company cannot prove that any specific plant will be retired by a specific date with absolute certainty. The Staff points to the fact that the Company has not made any provision for replacing power from retired plants in its Integrated Resource Plan filed in December, 2005, and recognizes that in any event, utilities do not have any practical way of knowing the exact retirement dates of a plant until relatively close to the time the plant is retired. (Mathis, surrebuttal, pp. 8-9.) Based on the latter point, Ms. Mathis appears to recognize that no utility could ever know the retirement date of any power plant with sufficient certainty to satisfy the Staff that the life span approach should be

[220] Staff apparently took this same flawed approach in the recent Kansas City Power & Light Company rate case, in which the Commission noted, “…it is unclear what Staff did in its lifespan analysis, and Staff seems to inaccurately presume that certain generation-related assets have an indefinite life.” Case No. ER-2006-0314, Report and Order issued December 21, 2006, p.51.

used. In other words, Ms. Mathis is setting a standard for the use of the life span approach that no utility could ever meet.

The Staff's position on life span is completely unsupportable. Of course it is true that AmerenUE, like all of the other electric utilities in the country, does not know with absolute certainty the exact date that each of its power plants will be retired. If it was necessary to know that information in order to implement the life span approach, the life span approach would not be used by all, or virtually all of the other states in the country. The truth is that it is appropriate to use the life span method based on reasonable estimates of the retirement dates for the power plants—just like depreciation rates are set based on reasonable estimates of the lives of other property providing service to customers. Reasonable estimates can be refined and revised over time as new information becomes available. The use of reasonable estimates of the lives of power plants is clearly preferable to the Staff's approach of assuming that each power plant will last to infinity.

In this case the Company has provided reasonable retirement dates for each of its power plants to be used in implementing the life span approach. In its direct case, the Company estimated an average retirement date for its fossil plants of 2026. (Stout, surrebuttal, p. 2.) This was not meant to indicate that the Company believed it would retire all of its fossil plants in the same year—it represented an average expectancy for the retirement of the plants. In response to Staff's criticism of the Company's selection of a single average retirement date for all of the fossil plants, in surrebuttal testimony, Mark Birk, AmerenUE's Vice President of Power Operations, provided a specific estimated retirement date for each fossil unit. Based on Mr. Birk's testimony, the Meramec Plant is estimated to be retired in 2021, after 63 years of service; the Sioux Plant is estimated to be retired in 2027, after 60 years of service; the Labadie Plant is estimated to be retired in 2033, after 61 years of service; and the Rush Island Plant is expected to be retired in 2037 after 60 years of service. (Birk, surrebuttal, p. 2.) The reasonableness of these estimated retirement dates is confirmed by the information on the actual life spans of over 200 retired steam production plants attached as Schedule WMS-3 to the direct testimony of Mr. Stout. This shows that the average life spans for these plants was 46 years. Mr. Stout also testified that in his considerable experience, average life spans for similar plants throughout the electric industry range from 40 to 60 years, so that AmerenUE's estimated plant lives are near or above the upper end of that range. (Stout, direct, p. 15.)

Again, the estimated lives for AmerenUE's power plants will not be carved in stone. If new information comes to light that indicates the plants' lives will be slightly longer or slightly shorter, adjustments to the depreciation rates can be made along the way. But if the Commission takes the unusual step of completely rejecting the life span approach, as recommended by the Staff, and power plant components are depreciated over long periods of time (80, 90, 100 years or longer) ignoring the reality that the plants will eventually have to be retired, the Company will be left with a large amount of undepreciated plant whose costs will inappropriately be paid by future generations of customers, not served by the retired plant. This result is directly contrary to the fundamental goal of depreciation accounting, which is to allocate the service value of a piece of property (original cost less net salvage) over the service life of the property. (Stout, direct, p. 7.)

For all of these reasons, the Commission should adopt the mainstream practice of recognizing the reality that power plants must eventually be retired through the adoption of the life span approach.

B. Callaway Nuclear Plant Life.

A second policy issue that the Commission is called upon to decide in this proceeding is whether the estimated life of the Callaway Nuclear Plant should be until 2024, the date of the expiration of its current operating license issued by the Nuclear Regulatory Commission (NRC), or if it should be extended until 2044, incorporating a possible 20-year extension of the NRC operating license that AmerenUE has not yet determined whether it will seek.

AmerenUE witness Charles D. Naslund, AmerenUE's Chief Nuclear Officer, has provided testimony explaining that the Callaway Plant is only just over halfway through its initial license life, and that a decision to seek an extension of the operating license will not be made, and should not be made, until around 2014. The Company's decision to seek (or not seek) a license extension will depend on data it will gather on the condition of the plant and its components over the next 8 years. The single most critical consideration in this regard will be the condition of the reactor vessel itself. Mr. Naslund testified that the cost of operating the plant will also be a factor which can be impacted by a number of considerations including changing regulatory requirements, increases in the cost of purchasing fuel or disposing of spent fuel rods, and increases in plant operations and maintenance costs. Moreover, the costs of operating the Callaway Plant will have to be compared to the cost of other power sources at the time the relicensing decision is made. Notwithstanding this uncertainty, Mr. Naslund testified that the Company has taken steps to preserve the *option* of relicensing the plant in the future if that is an appropriate decision. (Naslund, direct, p.p. 9-10.)

In their direct testimony, a number of witnesses for other parties (Staff witness Warren T. Wood, State of Missouri witness Michael Brosch, OPC witness William Dunkel and MIEC witness James Selecky) all opined that the Commission should presume a 20-year extension of the Callaway operating license simply because a number of other electric utilities had announced their intention to extend operating licenses for other nuclear plants. Mr. Naslund responded to these witnesses in his rebuttal testimony, explaining with greater specificity some of the uncertainties that will impact AmerenUE's decision to seek a license extension for Callaway, and that may also influence the NRC's decision to grant or deny such an extension. Specifically Mr. Naslund cited the potential for terrorist attacks on nuclear plants in the U.S. or worldwide, the potential for lack of adequate water supplies in the Missouri River to cool the plant, political changes that may affect the viability of nuclear plants in the future, safety issues that arise with nuclear plants in Callaway's "generation" of plants, and economics that do not support life extension. Mr. Naslund noted that many, many components of the Callaway Plant (approximately 130,000) and miles of cable and piping which were initially specified for a 40-year life would have to be assessed, and potentially replaced, before life extension would be an option. For all of these reasons, Mr. Naslund supports the use of 2024 as the estimated retirement date for the Callaway Plant. (Naslund, rebuttal, pp. 2-4.)

Mr. Stout also provided testimony that use of 2024 as the retirement date for the Callaway Plant is appropriate based on depreciation principles. Although Mr. Stout acknowledged that it was possible the plant's operating license would be extended, it was also quite possible that the license would not be extended. (Stout, direct, p. 30.) Also, Mr. Stout pointed out that even if the license were extended, the extension would only be granted if AmerenUE replaced any number of components to the plant. Since these types of retirements are not reflected in the interim retirement curves used by Staff witness Mathis in calculating depreciation rates for nuclear accounts, it is not appropriate to presume an extension of the plant's life in calculating these same depreciation rates. (Stout, rebuttal, pp. 15-16.) In addition, Mr. Stout noted that it is appropriate for the life of the plant used for purposes of depreciation to be equal to the life of the plant used for calculating accruals to the nuclear decommissioning fund. Since the Commission's regulations (4 CSR 240-3.185) require calculating the decommissioning funding requirements over the license life of the plant (presumably based on the numerous uncertainties surrounding a plant's ability to get a license extension) it is also appropriate that depreciation rates be developed based on the same date. (Stout, direct, p.31.)

Finally it is noteworthy that the consequences of underestimating the life of the Callaway Plant are far less serious than the consequences of over-estimating the plant's life by 20 years, if a license extension is not granted, similar to the situation with the life span issue. If a retirement date of 2024 is used in developing depreciation rates in this case, and it turns out later that the issues raised by Mr. Naslund are resolved and AmerenUE actually seeks a license extension, depreciation rates can be revised with relatively minor impact on customers' rates. Customers taking service early in the plant's life (beginning in 1984 until the plant's life is extended) will pay depreciation rates that, in hindsight, were slightly too high, and customers taking service later in the plant's life will pay depreciation rates that, in hindsight, are slightly too low. In contrast, if the Commission assumes the extension of the Callaway Plant's life now, and the plant's license is actually not extended, the Company will be left with large undepreciated balances in its nuclear accounts that will have to be recovered from customers after the plant is retired. These same customers will be paying additional depreciation costs related to the plants that AmerenUE had to build or buy to replace Callaway. This result is far more inequitable to customers than the result that would occur if a retirement date of 2024 is used to set depreciation rates in this case, but gets extended by 20 years at a later date. For all these reasons, the Commission should not change the 2024 retirement date for Callaway in this case.

C. Net Salvage.

In their proposed treatment of net salvage for distribution, transmission and general plant, MIEC witness James Selecky and OPC witness William Dunkel are essentially attempting to relitigate the decision that the Commission reached on net salvage for these accounts in Case No. GR-99-315. As the Commission may recall, this case unfolded over approximately 6 years, involved the participation of AmerenUE, Laclede, Staff and the Office of the Public Counsel, and culminated in a three-day hearing in which the treatment of net salvage for mass property accounts (distribution, transmission and general) was exhaustively examined by the Commission. Notwithstanding the Commission's decision in that important case, the OPC and MIEC are attempting to adjust the treatment of net salvage the Commission approved in that case in a never-ending effort to drive the Company's depreciation rates lower. OPC and MIEC rely on two separate theories to make their adjustment. First they argue that past levels of inflation, which are implicitly built into the development of net salvage percents, are not representative of future levels of inflation because they are too high. (Selecky, direct, p. 33; Dunkel, direct, p. 18.) Second, as an alternative position, Mr. Selecky's argues that net salvage percents should be based on the current level of net salvage expense. (Selecky, direct, p. 37.) This is the issue that was at the very heart of the Commission's decision in Case No. GR-99-315 to use the traditional and widely accepted method of accrual accounting rather than expensing for net salvage!

Mr. Stout provides testimony explaining why the inflation adjustment proposed by Messrs. Selecky and Dunkel is inappropriate. Mr. Stout explains that these witnesses have attempted to implement their proposed adjustment by removing historic inflation from the net salvage calculation, and then adding back a factor to account for their estimate of future inflation. Both calculations are flawed. Mr. Stout points out that the historic inflation that is being removed from the calculation of net salvage is overstated, because the average age of the plant that has been retired in the last 45 years is significantly less than the average service life for each applicable account. This is because historic retirements have occurred on the early part of the survivor curve. Conversely the estimate of future inflation that is being added back into the calculation is understated, because future retirements of plant will be at ages above the average life for the account. This effect can be analogized to human life expectancies. Humans who have lived for a number of years have greater life expectancies than the "average life expectancy" at birth. Proper accounting for this consideration would mean that net salvage percents should be increased, not decreased, from the levels developed under the traditional approach. (Stout, surrebuttal, pp. 5-9.)

In summary, the adjustments proposed by Messrs. Selecky and Dunkel to net salvage applicable to distribution, transmission and general accounts should be rejected because (a) they are flatly inconsistent with the decision of the Commission in Case No. GR-99-315; and (b) in any event, if properly calculated, the inflation adjustment would result in an increase in the net salvage percent calculated in accordance with the traditional accrual of net salvage pursuant to the Commission's decision in Case No. GR-99-315.

D. 4 CSR 240-10.020.

In direct testimony, the Company stated its position that 4 CSR 240-10.020 applies to the Commission's accounting for income that a utility derives from investment of funds collected through depreciation rates. Essentially that rule requires that in the process of setting rates, the Commission must provide the utility's customers with a 3% annual credit to reflect income from investment of the money in the utility's depreciation reserve account. The rule applies regardless of whether the utility's depreciation reserve account is represented by a fund earmarked for that purpose. (Weiss, direct, p. 29.)

The Company acknowledges that neither the Commission nor utilities have generally followed this rule in recent years. Instead of providing customers the 3% credit as contemplated by the rule, the Commission has consistently deducted accumulated depreciation from original cost rate base, and applied the rate of return to the net rate base resulting from this calculation. AmerenUE has calculated the impact of applying this rule in this case and determined that application of the rule in this case would increase the Company's requested revenue requirement by an additional $264 million. (Weiss, supplemental direct, pp. 29-30.) The Company has not requested rates reflecting this additional increase, but it has cited this rule as additional support for the rate increase that it is requesting.

Staff witness Robert Schallenberg and State witness Brosch oppose application of the rule in this case. In addition, they argue that one reasonable interpretation of the rule is that the 3% credit is in addition to the benefit that customers get from deduction of the accumulated depreciation reserve from the original cost rate base. (Schallenberg, rebuttal, pp. 14-15; Brosch, rebuttal, pp. 7-8.) However, this would result in an improper double crediting to customers, and the history of the rule makes it crystal clear that such an application was not intended. In the Commission order that implemented the rule, the Commission stated: "It is obvious, however, that if the utility's allowable return is reduced by income on depreciation funds, the utility rate base upon which the allowable return is predicated, should be an undepreciated rate base." 27 Mo. P.S.C. Reports 293 (1946). This interpretation is also consistent with the Staff's position on application, in Case No. EC-2002-1, as reflected in a portion of a deposition of Staff witness

Greg Meyer, attached to Mr. Weiss' surrebuttal testimony as Schedule GSW-E41. Based on the foregoing, the Company believes its interpretation of 4 CSR 240-10.020 is correct.

E. Other Depreciation Issues.

There are additional depreciation issues raised in the testimony of the Company and the Staff. The Company and Staff have reached a settlement in principle on these issues, and so the Company will not address them in this brief. If the settlement in principle is not ultimately finalized, the Company reserves the right to address these issues at the hearing and in post-hearing briefs.

Class Cost of Service and Rate Design Issues

17. ***Class Cost of Service and Rate Design: What should be the increase or decrease in the revenue responsibility of each customer class?***

A. To what extent, if any, are current rates for each customer class generating revenues that are greater or less than the cost of service for that customer class?

The results of AmerenUE's updated Class Cost of Service Study are contained in the Surrebuttal Testimony of William M. Warwick, Schedule WMW-E4. These results of AmerenUE's CCOS study indicate that the residential and large primary classes are not providing a comparable return on rate base in comparison to all other major classes of customers.

The individual classes' rates of return at current rates vary, and are shown in the following table, based upon current rates for the 12 months ended June 30, 2006:

Missouri	Residential	Small GS	Large GS	Small Primary	Large Primary	Large Trans
2.915%	0.514%	5.158%	6.838%	4.702%	0.909%	7.601%

According to the Surrebuttal Testimony of Staff witness David C. Roos, the following table summarizes the positions of the various parties submitting class cost of service studies regarding the percent change in class revenues required to equalize class rates of return on a revenue neutral basis:

COMPARISON OF THE RESULTS OF THE CLASS COST OF SERVICE STUDIES
THE PERCENT CHANGE IN CLASS REVENUES REQUIRED TO EQUALIZE CLASS RATES OF RETURN
(REVENUE NEUTRAL)

	Mo Retail	RES	SGS	LGS	LPS	LTS
AmerenUE (A&E)[1]	**0.00%**	**8.20%**	**-6.10%**	**-8.70%**	**7.60%**	**-10.90%**
Staff (A&P)[1]	**0.00%**	**3.39%**	**-3.17%**	**-6.35%**	**10.19%**	**0.73%**
OPC (A&P)[1]	**0.00%**	**3.62%**	**-5.00%**	**-6.44%**	**13.24%**	**-0.68%**
OPC (TOU)[1]	**0.00%**	**-0.30%**	**-6.64%**	**-3.94%**	**20.05%**	**8.28%**
MIEC (A&E) #1	**0.00%**	**14.10%**	**-2.96%**	**-12.32%**	**-3.06%**	**-26.56%**
MIEC (A&E) #2	**0.00%**	**11.60%**	**-4.20%**	**-10.55%**	**1.00%**	**-19.90%**
MIEC (A&E) #3	**0.00%**	**15.70%**	**-2.30%**	**-12.94%**	**-5.50%**	**-30.80%**
AARP (A&P)	**0.00%**	**1.60%**	**-8.06%**	**-3.52%**	**17.60%**	**-1.26%**

B. How should AmerenUE's cost of service be assigned to the customer classes?

AmerenUE witness William M. Warwick sponsors AmerenUE's Class Cost of Service Study (CCOS) in this proceeding. In his Direct Testimony, he explains that the CCOS study allocates the various costs identified in the cost of service study to each of the Company's rate classes, to determine as accurately as possible the cost of serving each of the Company's rate classes.[221] The Company's class cost of service study allocates, or distributes, the total jurisdictional costs to the various customer classes in a cost based manner that fairly and equitably reflects the cost of the service being provided to each customer class.[222] AmerenUE recommends that the Commission adopt its cost of service study approach, as explained in more detail in the following sections of this brief.

[221] Warwick Direct, pp. 2-14.
[222] Cooper Direct, p. 8.

AmerenUE conducted a detailed analysis of all elements of investment and expense associated with the Company's Missouri electric operation for the purpose of allocating such costs to the non-lighting customer classes served by the Company. As a part of this analysis, total expenses and investment in property and plant were classified into their customer-related, energy-related and demand-related components.[223] The allocation factors for each customer class were determined by calculating the proportionate share of total customer or property units of each class and the total energy or demand related units of each class, including applicable losses. These allocation factors were then applied to the various functional components of rate base and operating and maintenance expenses, as developed in total for the Company's Missouri jurisdictional operations.

C. Should the Commission adopt AmerenUE's proposal to cap any residential class increase at no more than ten (10%) percent?

Yes. As explained by AmerenUE witness Phillip Hanser, AmerenUE proposes that the increase in revenue requirement to be collected from the residential customer class, as a whole, would be capped at no greater than 10 percent.[224]

AmerenUE believes that rate stability for the residential class is an important goal in this case. Residential customers' options to adapt to higher prices may be more limited than other classes. In addition, some consumers do not have the financial resources to easily absorb electric rate increases. Nonresidential customers, on the other hand, may have the ability to pass along underlying cost increases to their own customers, as well as better access to capital markets to finance any changes in their structures or energy using equipment to respond to changes in energy prices.[225]

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[223] *Id*. at 3.
[224] Hanser Direct, pp. 5-13.
[225] Hanser Direct, pp. 5-6.

D. Should Staff's proposal to combine the Small Primary Service Class and the Large General Service Class in the Class Cost of Service Study be adopted?

This is no longer an issue between AmerenUE and Staff. AmerenUE understands that Staff is proposing to combine the Small Primary Service Class and the Large General Service Class for rate design purposes only. AmerenUE supports this position.

E. On what basis should production capacity be allocated to classes?

The Company used an allocation method called the Four Non-Coincident Peak (4 NCP) Average and Excess Demand method to allocate production plant. As explained by AmerenUE witness Wilbon C. Cooper, this method gives weight to both class peak demands and class energy consumption by its inclusion of both average class demands, which are kilowatt hours divided by total annual hours (8,760), and the excess NCP demands of each class. The 4 NCP version of the A&E methodology, which uses the four maximum non-coincident monthly peak demands for each customer class during the test year, was selected due to the fact that 15 of the 24 maximum 4 NCP monthly demands for the Company's six major customer classes occurred during the Company's summer peak demand months of June-September.

AmerenUE, Noranda, and The Commercial Group (TCG) have all provided testimony in support of the use of the 4NCP A&E allocation method for fixed production plant cost allocation, while the remaining parties have sponsored other methods for allocating production plant. As explained in the Rebuttal Testimony of Mr. Cooper, the Company's net investment in fixed production assets represents approximately 74% of the net original cost rate base and variations among the parties in allocating this investment have produced significant differences in class cost of service requirements in this case.[226] In reviewing the class cost of service results for each of the non 4NCP A&E methods sponsored by other parties in this docket, AmerenUE's

[226] Cooper Rebuttal, p. 14.

4NCP A&E method appears to produce class cost of service requirements (i.e. by class) that are fairly close to the middle of the range. While this does not suggest that the middle or the average is always the best road to take, it may lend some support to the reasonableness of the method proposed by AmerenUE.[227]

The Company's proposed 4NCP A&E method is superior to other proposals offered by certain parties in this case due to its more balanced consideration of both the energy and excess demands requirements for serving each customer class. As stated earlier, it has the support of Noranda and TCG, and has produced results that are fairly close to the middle of the results of all proposed methods for the allocation of production plant costs in this docket. For these reasons and those stated in the Rebuttal Testimony of Mr. Cooper, the Company recommends that the Commission adopt the 4NCP A&E for the allocation of production plant costs.

With the exception of Noranda who did not submit or endorse the Class Cost Of Service Study by any other party in the case, the following Table 1 depicts a summary of the positions of the various parties on this issue in direct testimony:

Table 1 – Summary of Parties' Production Plant Allocation Methodologies and Class Allocation Factors

Party	Method	RES	SGS	LGS	SPS	LPS	LTS	Total
Company (UE)	4NCP – A&E	46.57%	11.16%	19.62%	8.57%	8.30%	5.78%	100%
MPSC Staff	12 NCP – A &P	40.27%	10.57%	30.93% (LGS & SPS)	See LGS	9.83%	8.40%	100%

[227] *Id.*

OPC 1	3CP P&A	41.42%	10.48%	20.68%	9.57%	9.56%	8.29%	100%
OPC 2	TOU	36.52%	9.93%	21.80%	10.65%	11.09%	10.01%	100%
MIEC	3NCP – A & E	47.16%	11.23%	19.52%	8.42%	7.94%	5.72%	100%
AARP	4CP–P&A	40.98%	10.63%	20.92%	9.62%	9.59%	8.26%	100%
Commercial	4NCP – A&E	46.57%	11.16%	19.62%	8.57%	8.30%	5.78%	100%

F. On what basis should transmission costs be allocated to classes?

AmerenUE, OPC, and AARP allocated transmission line and substation investment to each customer class on the basis of twelve coincident (12 CP) demands of each class at their point of input to the Company's transmission system. Coincident peak demand is the customer class' peak load at the time of occurrence of the Company's system peak. The twelve coincident peak demands are the customer class' twelve monthly loads at the time of the Company's twelve monthly system peaks. All other parties, with the exception of AmerenUE and AARP, allocated transmission costs using their respective production capacity allocators.

AmerenUE contends that its 12 CP method is appropriate since the transmission system must be constructed to handle maximum system peak loads. It does not vary by plant, nor can it be dispatched at various running cost levels. Therefore, it is appropriate that transmission costs be allocated using a method which employs class demands during peak periods. In addition, such allocation mirrors or tracks the method by which such costs are incurred by the Company under the MISO.[228]

[228] Warwick Rebuttal, p. 6.

G. On what basis should distribution costs be allocated to classes? Should the allocation of primary distribution costs include any customer-related component?

The Company's distribution plant was allocated to each customer class based upon the results of a detailed analysis of the functions performed by the facilities in Distribution Plant Accounts 360-369. The portion of the distribution plant accounts assigned to the customer component was derived using the zero intercept method, a generally accepted and widely used methodology described in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual. As explained by Mr. Warwick, this approach to cost assignment is predicated on the fact that there is a zero or no load component in even the smallest available unit of distribution equipment. This zero intercept method identifies the portion of plant related to a hypothetical no-load or zero-intercept condition (i.e. the cost of simply making service available to the customer). This portion of the plant is allocated to the customer component, while the remaining demand-related portion of the distribution plant accounts was split between the primary and secondary voltage levels on the basis of a review of the functional utilization of various equipment and hardware in such accounts. With the exception of Account 369, Services, the demand-related investment in each account was allocated to each customer class on the basis of the non-coincident peak demand of each class at the appropriate primary and secondary voltage levels.

The primary difference among the parties with respect to the allocation of distribution costs is whether or not there is a customer-related component to a portion of the distribution system costs. AmerenUE, Staff, and MIEC classified a portion of Accounts 364-367 as customer-related and the remaining portion as demand-related. AARP, however, does not recognize any portion of these accounts as having a customer-related component. OPC does not recognize a customer-related component to the Primary portion of these distribution costs but does recognize a customer-related component to the Secondary portion of costs in these distribution accounts

The positions of AmerenUE, Staff and MIEC on the proper allocation of distribution costs are consistent with methods recognized in NARUC's Electric Utility Cost Allocation Manual. Contrary to the position of Public Counsel and AARP, more than the costs associated with services, meters, meter installation and customer account expenses should be included in a class' customer charge component. As recognized by the approach recommended by AmerenUE, Staff and MIEC, there is a customer component to Accounts 364-367 which should also be included in class customer service charge.

H. On what basis should non-fuel generation expenses by allocated?

The Company has classified only the operating labor expense and purchased power-capacity costs as fixed costs. As explained by Mr. Warwick, all other production expenses vary with the amount of generation and should be classified as variable expenses.[229]

Public Counsel and MIEC have allocated more of non-fuel generation expenses using a fixed production allocator than AmerenUE, Staff and AARP. AmerenUE believes that the Company's method should be adopted since all the other production expenses vary with the amount of generation and should be classified as variable expenses. It is also consistent with the Company's classification and allocation of these expenses in AmerenUE's jurisdictional cost of service study.[230]

[229] Warwick Rebuttal, p. 5.
[230] Warwick Rebuttal, p. 5.

I. On what basis should off-system sales revenues be allocated among the customer classes?

Initially, the Company allocated off-system sales revenues based upon its production capacity allocation method, and Staff accepted Company's allocation. This initial proposal was based on the historical practice of allocating all off-system sales margins based on each class' fixed production allocator, and allocating the fuel expenses associated with these sales based on each class' variable production or energy allocator.

However, MIEC suggested two alternative methods for allocating off-system sales revenues. After considering the positions of MIEC, AmerenUE now recommends that off-system sales be allocated in the same manner as costs for those same assets were allocated, resulting in equitable treatment of costs and revenues. Under this alternative method, the profit or margin from off-system sales is allocated using each class' production capacity allocation factor, with the remaining fuel costs being allocated to each class based on its energy allocator.[231]

J. On what basis should credit and collection expenses be allocated?

Contrary to the assertion of MIEC witness Brubaker, AmerenUE has not changed its method of allocating credit and collection expenses. As in past cases, AmerenUE has weighted charge offs and credit and collection expenses. These expenses were then allocated to Account 903 Credit and Collection, based upon the Company's records which contained the charge off amounts by rate class (i.e. direct assignment). AmerenUE believes the traditional method of allocating credit and collection expenses should be continued in this case.

[231] Warwick Rebuttal, pp. 5-6.

18. Rate Design: How should the Commission implement any revenue change it orders in this case and address proposed revisions to existing tariffs?

A. Should the Commission adopt AARP's proposal to recover less of the Company's demand related costs in the summer, and more of the demand related costs in the winter?

No. The Company has utilized the results of a study performed to allocate distribution demand related costs to the summer and winter billing seasons. This type of study has been utilized in all of the Company's rate cases since 1987 and reflects analyses of summer and winter demands with average and excess allocation method to determine summer (60%) vs. winter (40%) revenue responsibility for these costs. AARP has not challenged the Company's analyses, but rather arbitrarily recommends that only 55% of such costs be recovered in the summer with the remaining 45% to be recovered in the winter. Since AARP has provided no cost support for his recommendation, the AARP position should be rejected by the Commission. Instead the Commission should continue to adopt the Company's 60/40 summer to winter split of the distribution revenue requirement based on cost support and, also, existing customers' familiarity with same.[232]

B. Should the Commission adopt the Missouri Association for Social Welfare's proposal to create an "essential service rate"?

No. The Commission should reject the proposal of the Missouri Association for Social Welfare (MASW) to establish an essential services rate for residential customers. There are several problems with MASW's proposal. First, MASW witness Robert Quinn relies on assertions to demonstrate that additional low-income assistance is needed, without acknowledging the low-income programs already in place. Second, the absence of an income test means that high-income customers would receive an unnecessary benefit. Third, the inverted block rate resulting from Mr. Quinn's proposal would reduce retail customers' incentive

[232] Cooper Rebuttal, p. 10.

to invest in energy efficiency (*e.g.*, insulation, efficiency appliances) and would penalize low-income customers with high levels of electricity consumption.

C. Should the Commission adopt AmerenUE's economic development and retention riders?

Yes. As explained in the Direct Testimony of AmerenUE witness Robert J. Mill, AmerenUE is proposing two economic development tariffs in this proceeding: Economic Development and Retention Rider (EDRR) and Economic Re-development Rider (ERR).[233] Staff also supports the approval of these economic development initiatives and recommends the Commission approve both of these riders.[234]

AmerenUE historically had an economic development tariff in place called Rider EDR (Economic Development Rider) that provided rate benefits to qualifying customers. However, on March 31, 2006, AmerenUE's Rider EDR expired under its own terms for new loads. Customers that had previously qualified for Rider EDR will be able to complete the remaining balance of their specific 5 year term for the applicable discount to the extent they continue to qualify.

In this proceeding, AmerenUE is proposing to renew the EDR rider. Rider EDR provided for a 15% discount to qualified customer loads served under the Company's Service Classifications 3(M) Large General Service Rate, 4(M) Small Primary Service Rate, and 11(M) Large Primary Service Rate. Additionally, electric service under this rider was only available to customers in conjunction with local, regional, or state governmental economic development activities where incentives had been offered and accepted by the customer who locates new or expanded facilities in the Company's service area. The availability of this rider was limited to industrial and commercial facilities not involved in selling or providing goods and services

[233] Mill Direct, pp. 2-11.
[234] Watkins Rebuttal, p. 2.

directly to the general public. Further, the qualifying customer had to add at least 200 KW of billing demand and maintain a 55% or higher load factor to stay qualified for this Rider.

The proposed Rider EDRR is structured very similar to the closed Rider EDR, except that Rider EDRR would require a new or expanding customer to first demonstrate that they are considering another viable location with a lower electric rate before AmerenUE would offer a rate discount. Additionally, EDRR provides economic incentives for retention of a customer's load that had announced plans to move substantial operations out of Company's service area for a more competitive energy supply source. The discount provisions of Rider EDRR for customer retention may be activated only after a customer: 1) formally announces plans to move operations; 2) provides satisfactory evidence to the Company of a viable competing electric service offering at a new location; 3) receives incentives not to relocate from a local, regional, or state governmental economic development activities; and, 4) declares that operations will not be materially reduced or moved.

AmerenUE respectfully requests that the Commission approve its proposals to enhance economic development initiatives throughout its service area.

D. Should AmerenUE have an Industrial Response program? If so, what should be the parameters of that program?

Yes. The Commission should adopt AmerenUE's Industrial Response Pilot (IRP) in this proceeding. The proposed Rider IDR is designed as a pilot program to assess whether industrial process customers are able to respond to load curtailments in exchange for a lower monthly demand charge. This Rider differs substantially from the former AmerenUE interruptible tariff (SC 10 (M)) and from existing Riders L and M, voluntary curtailment riders. Rider IDR requires customers to interrupt when directed to do so by the Company for reliability or other reasons, as specifically defined in the tariff. Rider IDR allows a customer to select the amount of curtailable load to be included in the program. The proposed amount of the demand charge discount has been established at a level to approximate the market value of regulated capacity. The proposed Rider IDR limits the number of annual hours available for interruption to 200. Once reached, no additional interruptions can be called until the new contract year begins. This program is being offered as a pilot program, meaning the duration is limited and we plan to conduct a study of its results. AmerenUE is also proposing to limit he availability of Rider IDR to no more than five (5) customers with a total demand response aggregated load of 100 MW.[235]

MEG witness Billie La Conte raises three concerns with respect to this program. First, she argues that the credit should be larger. Second, she asserts that the proposed limit should be raised from 100 MW to 800 MW. Third, Ms. LaConte contends that the period for the pilot program is too short. However, as AmerenUE witness Hanser explains, her concerns are not valid and should be rejected by the Commission.[236]

AmerenUE would urge the Commission to adopt its IDR proposal as a modest experimental program that is similar to other programs throughout the United States and are encouraged by the various regional transmission organizations. If approved, AmerenUE would be joining many other utilities in their exploration of the potential for customer participation in addressing resource needs.[237] Through voluntary curtailment, the IDR pilot program has the effect of (1) ensuring firm supply to non-interruptible customers, (2) potentially avoiding the use of external purchases of high cost energy, which reduces price volatility, and (3) lowering enforcement costs, which reduce social costs in the application of the pilot program. Thus, the IDR program improves service reliability and reduces price volatility.[238]

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[235] Mill Direct, pp. 11-12.
[236] Hanser Rebuttal, pp. 12-13.
[237] Hanser Direct, pp. 15-16.
[238] Hanser Direct, p. 16.

E. Does the Large Primary Service Rate need to be changed? If so, should the Commission adopt AmerenUE's proposed changes to the Large Primary Service Rate?

Yes. The Large Power Rate should be changed, as proposed by AmerenUE in this proceeding. AmerenUE's proposed LPS tariff contains a provision for a discount of 10% to the energy component of customers within the LPS class who have demonstrated an annual load factor of at least 80% and also a provision requiring that all primary voltage customers with demands at or above 5,000 kW be served under this classification.

As explained by AmerenUE witness Wilbon C. Cooper, the proposed energy charges for the LPS class reflect the inclusion of 15% of the LPS production demand along with annual average variable energy cost that was derived from the LPS energy related production cost. This inclusion of a portion of fixed production related cost in the energy charge increases the probability that all energy delivered under the LPS tariff provides a positive contribution to margin or fixed production costs. However, cost causation principles support a lower per unit contribution to fixed costs for customers within a class demonstrating load factors noticeably higher than the class average.[239] AmerenUE's proposed LPS rate is consistent with these cost causation principles, and should be adopted by the Commission in this proceeding.

F. Does the Large Transmission Service Rate need to be changed? If so, should the Commission adopt AmerenUE's proposed changes to the Large Transmission Service Rate?

Yes. The Large Transmission Service Rate should be changed, as proposed by AmerenUE in this proceeding. The Company's existing LTS rate was developed outside the context of a rate case and was structured and designed to be as close as practicable to the Company's existing LPS rate. It was also intended to produce an annual cents per kilowatt-hour realization equivalent to the realization that would have been experienced if a customer taking

[239] Cooper Direct, pp. 32-33.

service under the new LTS rate had been taking service under the existing LPS rate, taking into consideration, however, certain unique characteristics of the customer and the service it would take under the new LTS rate. Thus, the existing LTS rate can be assumed to reflect the same rate design considerations as the Company's LPS rate, excepting the introduction of an Annual Contribution Factor (ACF). As part of a negotiated settlement in the Noranda case (Docket No. 2005-0180), the ACF was utilized as an adder to the LTS rate to effectively bill Noranda Aluminum on the LPS rate that was in effect at the time.

Considering the Company's class cost of service study filed in this case which lists Noranda as a separate rate class with its own cost based revenue requirement, Noranda's revenue requirement can easily be achieved with a simple rate design structure similar to that of the LPS class without any of the complications associated with an ACF. AmerenUE respectfully requests that the Commission adopt its proposed LTS rate in this proceeding

G. Should the Commission adopt AmerenUE's proposed changes to miscellaneous tariff provisions?

H. Should the Commission adopt Staff's proposal for changes to miscellaneous tariff provisions?

AmerenUE has proposed numerous changes to miscellaneous tariff provisions that are discussed in the Direct Testimony of AmerenUE witness Cooper.[240] The primary changes to miscellaneous tariff provisions include changes in the following areas: (1) unnecessary trip charges; (2) seasonal reconnect language; (3) overhead extensions to residential subdivisions; (4) removal of references to the use of "seasonal revenues"; (5) extension of the deficiency payment period for line extensions in areas where competition exists with rural electric cooperatives; (6) removal of certain single simultaneous demand or "coincidizing" demand language from the Rules and Regulations; (7) modification of tariff language related to

[240] Cooper Direct, pp. 37-42.

individual metering of multiple occupancy buildings; (8) modification of the non-residential Billing Adjustment tariff provisions, and (9) numerous other minor miscellaneous changes.

AmerenUE believes that most of these proposed changes to miscellaneous tariff provisions are relatively minor in nature, and are largely intended to improve the administration of its tariffs.

As explained by Staff witness William L. McDuffey, Staff has recommended approval of AmerenUE's proposals in the following areas: (1) service call charges (i.e. unnecessary trip charge); (2) changes to Rider B and Rider C tariff language; (3) most of the Municipal Underground Cost Recovery Rider changes; (4) large lot subdivisions; (5) deletion of seasonal revenues as an offset to the cost of relocating distribution facilities for non-residential extensions; (6) deletion of language related to Special Demand Metering Equipment; and (7) Billing Adjustment Periods.[241]

Staff and Public Counsel expressed concerns in the following areas: (1) definition of residential customers; (2) use of estimated costs in the Municipal Underground Cost Recovery Rider; (3) provisions designed to level the playing field in competitive situations with unregulated electric cooperatives; (4) language changes addressing Multiple Occupancy Building Metering; (5) seasonal disconnect provisions; and (6) Public Counsel's concern regarding the Company's proposal of additional per foot fees from distribution facility extensions to large lots within a subdivision.[242] AmerenUE has addressed each of the Staff and Public Counsel concerns with specific miscellaneous tariff provisions in the Surrebuttal Testimony of Wilbon C. Cooper.[243]

[241] McDuffey Rebuttal, pp. 2-10.
[242] Cooper Surrebuttal, pp. 7-12.
[243] Cooper Surrebuttal, pp. 7-12.

AmerenUE believes that most areas of concern may be resolved by informal discussions with the parties to this proceeding.

CONCLUSION

For the reasons discussed herein, the Commission should adopt the Company's positions on the remaining contested issues in this case.

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing Prehearing Brief of Union Electric Company d/b/a AmerenUE was served via e-mail, to the following parties on the 6th day of March, 2007.

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/s/**James B. Lowery**
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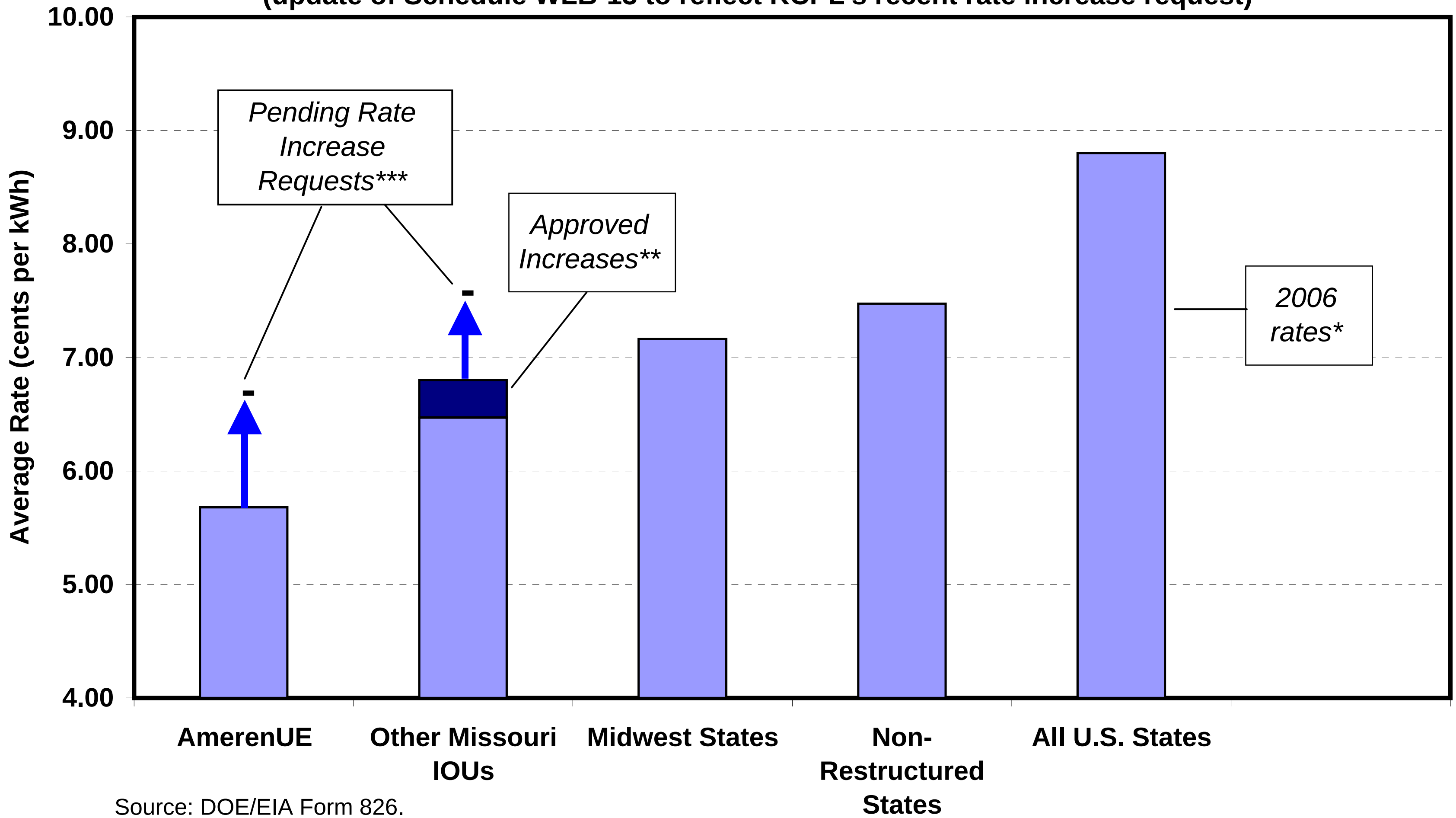
AmerenUE Average Retail Rates with Requested Increase Compared to Other Utilities

(update of Schedule WLB-13 to reflect KCPL's recent rate increase request)



Source: DOE/EIA Form 826.

* U.S. based on 2006 annual DOE data; rest based on rates in effect for twelve months ending October 2006.

** Rate increases recently approved for Empire District Electric and Kansas City Power & Light.

*** Arrows reflect initially-requested increases by AmerenUE and Aquila in their 2006 filings and KCPL in its 2007 rate filing.

Non-restructured states are those states that have not deregulated the generation of electricity, similar to Missouri.

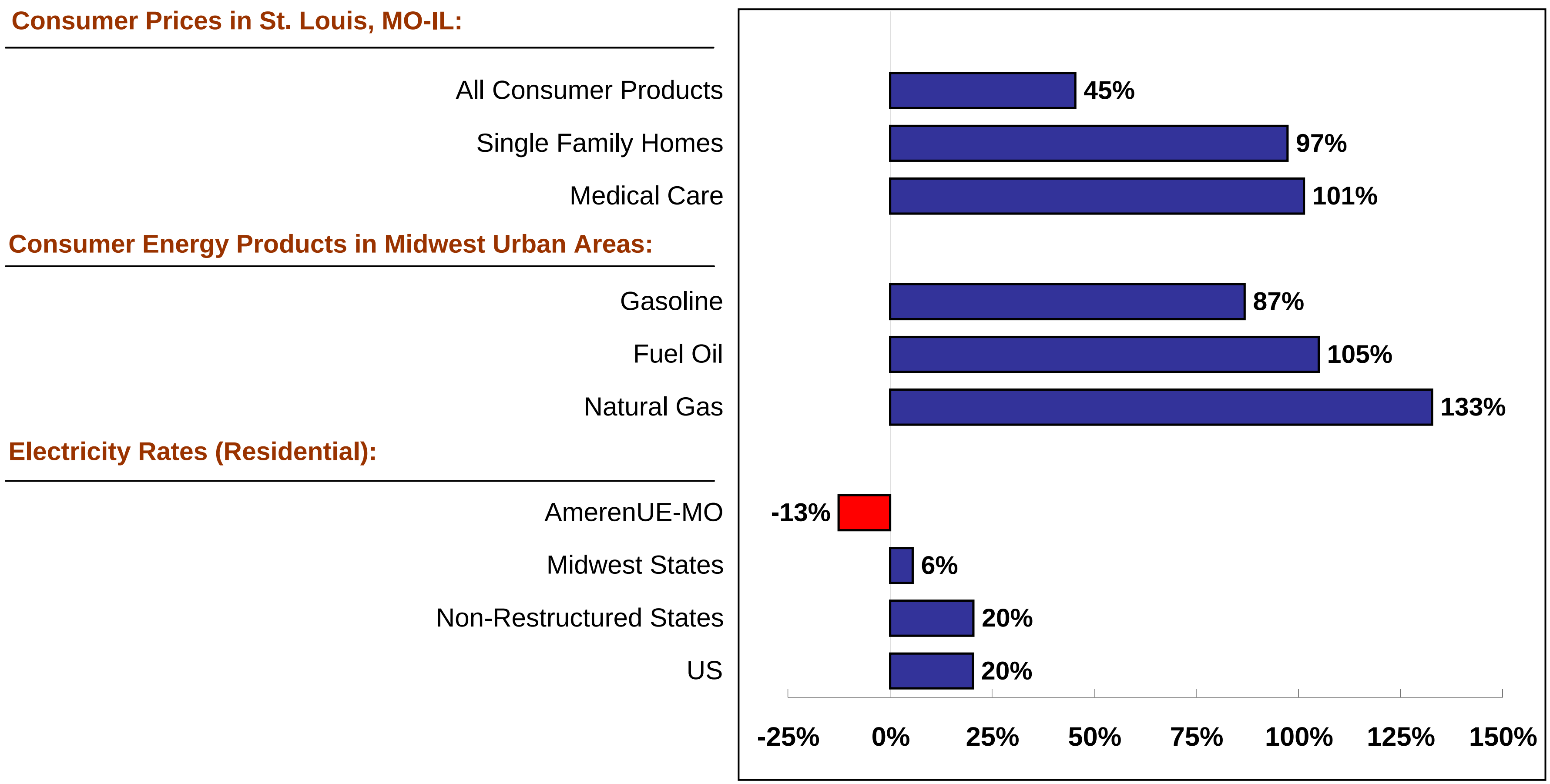
Midwest states based on Census Region definitions.

Other Missouri IOUs are Aquila, Empire District Electric, and Kansas City Power & Light.

Retail customers include residential, commercial, and industrial customers.

Exhibit 1

1990-2005 Changes in Electric Rates & Consumer Prices



Sources and Notes:
Consumer prices based on Bureau of Labor Statistics (BLS) St. Louis CPI indices and Office of Federal Housing Enterprise Oversight data.
Consumer energy prices based on BLS Midwest Urban average prices.
1990 rate data from EIA Form 861. 2005 rate data from DOE/EIA Form 826.
Midwest states based on Census Region definitions.
Non-restructured states are those states that have not deregulated the generation of electricity, similar to Missouri.

Exhibit 2