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	)	Case No. ER-2007-0002
Service Provided to Customers in the	)	
Company's Missouri Service Area.	)	

POST-HEARING BRIEF OF UNION ELECTRIC COMPANY D/B/A AMERENUE

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TABLE OF CONTENTS

BEFORE THE PUBLIC SERVICE COMMISSION
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Introduction

The last nine months have been an extremely difficult period for AmerenUE's customers and AmerenUE. As the Commission is well aware, the Company's service territory was rocked by a catastrophic thunderstorm in July, 2006 followed by two unusual ice storms in November/December, 2006 and January, 2007. Hundreds of thousands of customers were left without power in the wake of these weather events, and despite the Company's best efforts to restore service quickly under adverse conditions, many customers remained without power for a week or more. Customers were understandably upset about their loss of service, particularly if they lost service in more than one of the storms. In the local public hearings held in January in locations affected by these storms, numerous customers expressed their frustrations over the then-recent outages.[1] Also, some customers testified at the local public hearings that AmerenUE has experienced recurring reliability problems on portions of its system having nothing to do with the storms.

Commissioner Appling summarized the feelings of the Commissioners after hearing the public testimony when he bluntly admonished Ameren CEO Gary Rainwater that the Commission has serious concerns about AmerenUE, and that it is incumbent on Mr. Rainwater to "go back to St. Louis and fix those problems."[2] As Mr. Rainwater acknowledged, there are

[1] It is noteworthy that attendance at local public hearings was significantly lower in locations where storm-related outages did not occur. For example, no witnesses testified at the Kirksville local public hearing, and only two witnesses testified at the Jefferson City local public hearing.
[2] Tr. p. 2130, l. 2-5.

operational issues on portions AmerenUE's system that must be addressed. The local public hearings demonstrated that in some locations, AmerenUE's system has not operated with the level of reliability our customers expect and deserve.[3] AmerenUE recognizes that it must fix the operational problems to the extent that they exist, and Mr. Rainwater has testified that he is committed to doing so.[4] The Company also recognizes that it must take all reasonable steps to "storm harden" its system to minimize the impact of increasingly frequent severe storms on customers, and to try to insure as best it can that the events of the last nine months are not repeated.

However, it is important to keep the scope of the operational problems faced by AmerenUE in the proper perspective in deciding this case. Although there were clearly examples cited at the local public hearings where service on some segments of AmerenUE's system has not been as reliable as customers expect even in the absence of a storm event, the evidence in this case also shows that AmerenUE's system-wide reliability has been slightly better than average for the industry, and that non-storm related reliability issues are not widespread or systemic. For example, Richard Mark, AmerenUE's Senior Vice President of Energy Delivery, testified that in 2005 AmerenUE's customers on average had fewer brief interruptions and fewer lengthy outages than the Midwest average and the national average. In addition, the length of AmerenUE's longest outages compared favorably to Midwest and industry averages.[5] Staff witness Warren Wood attended the vast majority of the local public

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[3] Tr. p. 2113 – 2114.
[4] Tr. p. 2131, l. 8-18.
[5] The study cited by Mr. Mark showed that AmerenUE customers averaged 3 brief interruptions in 2005, compared to the Midwest region average of 3.2 and the industry average of 3.4. The number of lengthy outages experienced by AmerenUE customers averaged 1.5 which was also below the Midwest and industry averages. The average longest outage for AmerenUE was 10.1 hours while the average for the Midwest was 11.6 hours and the industry average was 12.9 hours. Exh. 38, p. 6 l. 10-17. SAIDI and SAIFI, which are also measures of reliability presented in this case, are of little practical use in comparing the reliability of different utilities, because, as Staff witness Warren Wood acknowledged, there are "major differences" in how those measures are calculated by different utilities. Tr. p. 4372, l. 25 to p. 4375, l. 6.

hearings,[6] and he followed up with everyone that he spoke to that identified day-to-day reliability problems—a total of 9 customers.[7] After reviewing these customers' records, Mr. Wood found that 92% of the recorded outages that these particular customers experienced were due to storm events – not unrelated reliability concerns, and the other 8% of the outages were due to tree damage, device outages, vehicle accidents and "other unknown" causes.[8] Although it is not acceptable for any customers to experience consistently unreliable service, the scope of the problem revealed by Mr. Wood's follow-up analysis suggests that non-severe storm related reliability concerns on AmerenUE's system are less prevalent and problematic than one might have thought based only on the testimony at the local public hearings. This is not surprising, given that AmerenUE's reliability statistics have, in the recent past, been slightly above average and given that in the wake of the severe and unusual 2006 storms, it was not unexpected that the customers who did choose to testify at the local public hearings would be upset (and understandably so) with the severe inconveniences they had suffered in the months preceding those local public hearings.

At the local public hearings there was also testimony presented about localized vegetation management issues on AmerenUE's system. Mr. Wood's subsequent investigation verified some of those problems. However, the evidence in this case also shows that AmerenUE has been increasing its vegetation management expenses, is on schedule to meet all of existing commitments related to vegetation management (including the movement to 4 and 6 year tree trimming cycles) within the timeframes agreed upon and approved by the Commission in Case

[6] Mr. Wood testified that he attended between 10 and 12 of the local public hearings. He appears to have attended the hearings where the large majority of witnesses testified. For example, he attended the hearings in the St. Louis area where numerous witnesses testified. He did not attend hearings in Kirksville (0 witnesses) or Jefferson City (2 witnesses). Tr. p. 4359, l. 1-3; pp. 4369-4370.
[7] Tr. p. 4362, l. 1-4; p. 4369, l. 3-5.
[8] Tr. p. 4364, l. 12-16.

No. EW-2004-0583.[9] Also, the evidence shows that in 2006 AmerenUE spent more on vegetation management than all of the other Missouri utilities, both on an absolute basis and on a dollars-per-pole-mile and dollars-per-customer basis.[10] In this case, AmerenUE has also proposed a substantial enhancement of its vegetation management programs, both in terms of dollars guaranteed to be spent each year ($45 million) and the scope of tree trimming activities. This proposal has been approved by the Commission as part of the "Tier II Settlement." This enhanced vegetation management program will place AmerenUE at the forefront of vegetation management among utilities in this state, and probably throughout the country.

Public witnesses also provided evidence at the local public hearings (including photos) of what appeared to be outdated facilities in service on the AmerenUE system. In response to these criticisms, Mr. Wood conducted a statewide comparison of the age of transmission poles, distribution poles, transmission conductors and devices, and distribution conductors and devices and he found that AmerenUE's facilities were second newest among all Missouri utilities in every one of those categories.[11] Moreover, in response to the recent concerns about reliability, AmerenUE has developed comprehensive facility inspection programs over defined cycles that will provide the Commission and customers a much greater degree of assurance that all of the Company's facilities are fully capable of providing service in the future.[12] AmerenUE is also implementing a program to focus on customers experiencing repetitive outages, and it has committed to hiring a consultant to conduct an independent evaluation of the Company's electric distribution system and provide recommendations to "storm harden" the system.[13] In addition to the existing programs AmerenUE recently implemented—i.e. the use of lightning protection

[9] Tr. p. 4380, l. 12-20.
[10] Tr. p. 4383, l.4-20; Exh. 975.
[11] Tr. pp. 4370, l. 23-4371, l. 13.
[12] Exh. 68, pp. 4-6.
[13] *Id.*, pp. 7-8.

devices, automatic switching to limit outages, tap fusing to reduce restoration time, and pole inspection and treatment programs[14]—these new programs should materially increase the reliability of AmerenUE's system.

The bottom line is that AmerenUE takes the criticisms from the Commissioners and the customers who testified at the local public hearings in this case very seriously. The Company is following up with each witness that testified about reliability problems and is committing resources and taking steps to address the localized reliability issues that were identified at the local public hearings—particularly the customers who identified reliability problems unrelated to the storms. The Company is committed to enhancing the reliability of our system, both on an overall system-wide basis and a localized basis, and to fixing the problems that have been identified.

However, part of having the ability to maintain the system at acceptable levels is having enough money to invest in infrastructure, pay for reliability programs and maintenance costs, and pay all of the other expenses necessary to run an electric utility, particularly given that customer expectations and the degree to which everyone relies upon electricity in their day-to-day lives is increasing. AmerenUE has pointed out repeatedly in this case that its rates are among the lowest in the country, the Midwest region and the state, yet its costs—the cost of fuel, medical expenses for employees, raw materials such as copper and aluminum wire, components such as transformers, and numerous other items—are increasing rapidly. It is critical that the Commission set rates in this case that permit AmerenUE to recover its legitimate costs of doing business, that provide it the opportunity to earn a reasonable return, and that afford it access to the cost-effective capital necessary to make infrastructure improvements to its system.

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[14] Exh. 38, pp. 4-5.

Approximately six[15] major contested issues remain before the Commission: (1) combustion turbine generator rate base valuations;[16] (2) return on equity/capital structure;[17] (3) Electric Energy, Inc (EEInc.); (4) the proposed fuel adjustment clause (FAC)/off-system sales[18]; (5) emission allowances;[19] and (6) certain depreciation issues.[20] A fair resolution of each of these issues is critical to the Company's ability to continue to operate its system and make investments necessary to enhance its system for the benefit of its customers. The Company addresses each of these issues below, and the dollar value of these issues is detailed on Staff's Revised Reconciliation attached hereto as Appendix 1.

Contested Issues

I. Fuel Adjustment Clause.

A. Introduction.

Fuel and purchased power (FPP) expenses are the largest item of expense the Company incurs, and they comprise approximately 44 % of the Company's operations and maintenance (O&M) expenses, and are quite volatile.[21] The price of coal, coal transportation, nuclear fuel, and natural gas and oil – all of which are required to fire the Company's generating units – are

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[15] Plus the Office of the Public Counsel's (OPC) approximately $138,000 "Metro East" issue.
[16] An issue with OPC as to Peno Creek and Pinckneyville and Kinmundy and the State as to Pinckneyville and Kinmundy only – Staff is recommending no rate base disallowances.
[17] Only OPC has a capital structure issue.
[18] It is the Company's understanding, based upon the Staff's Revised True-Up Reconciliation filing made just about 24 hours ago, that OPC desires to add an entirely new, previously unsponsored adjustment to its case. As Staff describes OPC's new adjustment: "Finally, Public Counsel has asked the Staff to add a line item to the reconciliation entitled "Taum Sauk Hold Harmless - Capacity Sales" and has provided a quantification for this line item. The Revised True-Up Reconciliation reflects this line item as requested by Public Counsel." OPC's attempt to add this entirely new adjustment is improper, both because it violates the Commission's rules and the Commission's scheduling order in this case (both of which required OPC to propose adjustments in its direct case, and certainly to do so during one of the three rounds of pre-filed testimony OPC had an opportunity to file), and because it violates the Company's Due Process rights. The Company of course has had no opportunity to address this brand new issue, and has not seen OPC's arguments on this issue, having not seen OPC's Brief, but wanted to note for the Commission the impropriety of this adjustment and the expected reference to it in OPC's brief at the Company's earliest opportunity.
[19] Only OPC and the State have an emission allowance issue.
[20] The Company and the Staff have reached agreement on some, but not all, depreciation issues.
[21] Exh. 133 (Company's Revised True-up Accounting Schedules, Accounting Schedule 9 (Fuel and purchased power expense of $633.2 million divided by total operations and maintenance (O & M) expense of $1.5 billion = 44%); Exh. 16 (Neff Rebuttal).

set in national and international markets that are beyond the Company's control. The Company also relies upon purchased power to serve its load, and it is clear that Company does not and cannot control the price of power in the Midwest Independent Transmission System Operator, Inc.'s (MISO) Day 2 Markets. It is obvious that FPP costs are largely outside the Company's control, given that in 2007 alone the Company experienced increases of more than **$___** million in Powder River Basin (PRB) (Wyoming) coal and coal transportation costs. Further, an additional approximately **__** million in already-known cost increases for coal and coal transportation will occur in 2008 and 2009, and additional increases are expected to occur over the 2008-2010 time frame for significant amounts of coal that are not already under contract.[22] While the Company's contracting and hedging practices dampen, to some extent, the *volatility* of FPP costs, they certainly do not eliminate volatility. In addition, no party claims that the Company could have avoided past cost increases, could avoid expected future cost increases, or that somehow the Company could have exercised control over the coal and coal transportation markets that have driven these cost increases.

Four parties, principally, oppose AmerenUE's request for an FAC (Staff, OPC, the State, and AARP).[23] The Staff opposes the Company's request based upon the argument that somehow profits from off-system sales eliminate the need for an FAC. As discussed below, this argument is demonstrably flawed, and is in any event far less of an issue given that the Company, in response to concerns expressed by several parties, is proposing to net all off-system sales

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[22] Exh. 16, p. 7, l. 17 – 24; p. 8, l. 1-3 (AmerenUE witness Robert K. Neff Feb. 5 Rebuttal). **____________ ____ ____ ____ ____. ____________________**

[23] Other parties do not oppose the adoption of an FAC. For example, Noranda indicated that the Company's proposed FAC is "good enough" if adopted by the Commission, and the Missouri Industrial Energy Consumers (MIEC) principally wanted to ensure that off-system sales are netted against fuel costs in any FAC that is adopted, which the Company's proposal does. The Commercial Group has similarly indicated that it is not opposed to FACs.

revenues through its FAC. OPC, the State and AARP all make essentially the same argument – that is, that AmerenUE can sufficiently control its fuel and purchased power costs, that these costs are not in these parties' views sufficiently volatile, and that therefore an FAC is not warranted.

At bottom, the Commission should not be diverted from following through on its adoption of Senate Bill (SB) 179 rules by those who simply oppose FACs as a matter of principle.[24] While it is true that SB 179 is enabling legislation, and does not mandate an FAC for Missouri utilities, denying a properly structured FAC to Missouri utilities, including AmerenUE, would leave Missouri among just two other (out of 29) non-restructured states that do not utilize FACs.[25] Denying AmerenUE's request for an FAC would also leave AmerenUE among just three other (out of 24) non-Missouri utilities in non-restructured states with heavy reliance on coal-fired generation that do not have FACs.[26] Finally, denying AmerenUE's request for an FAC would leave AmerenUE among just seven other (out of 58) non-Missouri utilities in non-restructured states that do not have FACs.[27] None of the parties have disputed these statistics.[28] Neither the facts in this case, the law, nor sound regulatory policy support failing to

[24] OPC and the State, in particular, attempted through cross-examination to suggest that they do not oppose FACs generally, but just for AmerenUE. A review of the OPC's Comments filed in the FAC rulemaking docket (Case No. EX-2006-0672) (of which the Company asks the Commission to take official notice, pursuant to Section 536.070(6), RSMo.) demonstrates that while we can engage in a semantical exercise of "did OPC oppose or just not support the FAC rules," it is clear that the arguments made in those Comments, and in testimony in this case, are arguments that essentially attack single-issue ratemaking mechanisms generally. If that is not "opposition" to an FAC, which is a single-issue ratemaking tool, then frankly, the Company is not sure what is. The State's testimony in this case is similar. Many of State witness Brosch's arguments boil down to a criticism of single-issue ratemaking, and when asked to cite any case where he had supported an FAC, he could only cite Hawaii where, by his own admission, FACs must be used or else Hawaii utilities would literally be facing insolvency. Tr. p. 1090, l. 4-25; p. 1091, l. 1-4; l. 23-25; p. 1092, l. 1-2. These positions simply ignore the fact that (1) FACs are the predominant regulatory mechanism to address fuel costs (virtually all states utilize FACs and that the vast majority of utilities in non-restructured states, including almost all coal-based utilities, utilize an FAC (Exh. 20, Schs. MJL-3 and MJL-4)); and (2) even Missouri utilizes adjustment clauses in the regulation of its natural gas utilities.

[25] Exh. 20, Sch. MJL-3 (AmerenUE witness Martin J. Lyons, Jr.'s Rebuttal Testimony dated Feb. 5, 2007).

[26] *Id.* Sch. MJL-4.

[27] *Id.*

[28] In fact, Mr. Brosch specifically noted (Tr. p.1100, l. 12-13) that he does not disagree with these data.

make this mainstream regulatory tool available to AmerenUE to enable timely and efficient recovery of its prudently incurred FPP costs.

AmerenUE has proposed an FAC that is well designed, balanced, and that has been modified to address all or nearly all of the concerns expressed by the parties. Among other things, AmerenUE's proposed FAC:

- Nets 100% of off-system sales revenues against FPP costs, thus lowering overall FPP costs charged to customers and allowing customers to benefit from any increase in off-system sales margins above the base level of margins set by this Commission in this case. This addresses the central concern expressed by MIEC witness Maurice Brubaker and addresses Staff witness Michael Proctor's concerns about separating off-system sales from FPP costs in an FAC;

- Spreads recovery or return of over- or under-collections from one FAC adjustment period over a subsequent 12-month period – this addresses rate adjustment volatility concerns expressed by OPC witness Russ Trippensee and Noranda Aluminum, Inc. (Noranda) witness Donald Johnstone;

- Includes another volatility mitigation measure – a 4% cap and deferral mechanism applied separately to each rate class – that would dampen volatility in rate adjustments under the FAC, if FPP cost increases (net of off-system sales) exceeded 4% of average retail rates from one true-up year to the next – this too addresses, to its satisfaction, a specific proposal made by Noranda;[29]

- Is based upon historical costs, unlike FACs employed in the majority of other states, per the Commission's rules;[30]

- Allows for only three FAC adjustments per true-up year, which is one less than allowed by the Commission's rules, and is far less than the monthly adjustments employed in a majority of other non-restructured states that use FACs;[31] and

- Includes a sharing mechanism that will provide additional incentives to the Company to lower its net FPP costs (i.e., net of off-system sales revenues) to the extent the Company can generate more off-system sales or otherwise lower FPP costs below the base amount set by the Commission. Under this mechanism the Company will only benefit if it can first offset entirely the already known and expected additional FPP cost increases, and is consequently structured such that customers will benefit significantly from net FPP cost savings before the Company sees any rewards, and even after these cost increases are fully offset,

[29] Tr. p. 1158, l. 12-22 (Noranda witness George Swogger)
[30] Exh. 21, Sch. MJL-5 (Lyons Surrebuttal).
[31] *Id.*

> customers have the potential to gain more than twice the benefit the Company could gain from any further reductions.

The Commission should approve AmerenUE's request for an FAC. Doing so will support AmerenUE's credit quality, thus lowering AmerenUE's borrowing costs, which is critically important given the approximately $3 billion dollars of capital investment AmerenUE expects to make in just the next five years alone.[32] Approving AmerenUE's request for an FAC will also foster a constructive and more efficient regulatory environment, and will allow the Commission and AmerenUE to take advantage of this well-accepted and mainstream regulatory tool. Moreover, an FAC will provide AmerenUE with a mechanism to address the significant cost of service impacts that will occur as the tens of millions of dollars (in excess of **____** million over the next four years),[33] of largely uncontrollable fuel cost increases the Company will incur over the next few years. Without an FAC, it is likely that AmerenUE will be forced to file additional rate increase cases that could probably be avoided if an FAC is in place.

B. AmerenUE's FPP costs meet the "criteria" that are generally utilized when examining the need for an FAC.

Although presented in various forms by various witnesses, most if not all of the witnesses who oppose AmerenUE's FAC request outline certain criteria that they suggest should be applied in evaluating AmerenUE's FAC request. State witness Michael Brosch's testimony is typical, and in it, Mr. Brosch acknowledges that FAC mechanisms are generally employed when FPP costs are (1) large in relation to the total cost to provide electric service; (2) subject to market forces (rather than management control); (3) volatile and difficult to quantify in rate

[32] Tr. p. 476, l. 12-14 (AmerenUE witness Warner L. Baxter).
[33] Which, all else being equal, would represent nearly **___* basis points in reduced return on equity (ROE).

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cases; and (4) substantial enough to cause potentially significant earnings volatility if not tracked.[34] AmerenUE's FAC request meets each of those criteria.

Before addressing each of these four criteria in more detail, a 10,000-foot view of the overall arguments FAC opponents are making is instructive. At bottom, what these opponents argue is that because AmerenUE has wisely invested heavily in baseload coal and nuclear generation, AmerenUE may have a greater level of "control" over its fuel costs than a utility that relies heavily on natural gas-fired generation. There are several problems with this argument, including the fact, as explained below, that coal prices have become more volatile and are expected to increase over the next several years. Moreover, this reasoning suggests that the only utilities that can qualify for an FAC are those that were unwise in their investments in generation technology or that are less capable of managing some of their fuel volatility through hedging and contracting practices.

The "logic" employed by these opponents – that a utility with a lot of coal-fired and nuclear generation should be in effect ineligible for an FAC – leads to illogical results. Is it logical that when the Missouri Legislature enacted SB 179 and when this Commission adopted SB 179 rules, only the two smallest electric utilities in the State would be "eligible" for an FAC? Is it logical that the Legislature and this Commission had in mind leaving the two largest and lowest cost utilities in the State *outside* the mainstream of regulatory practice in the United States? Is it logical that the Commission would intend that a utility like AmerenUE, facing more than $150 million of upcoming fuel cost increases, would be required to file rate cases every year or two to recover its FPP costs, rather than using an FAC between the four-year rate case cycle mandated by SB 179? Is it logical that the Commission would want to mute the beneficial

[34] Exh. 502, p. 8, l. 7-14 (State of Missouri witness Michael Brosch's Direct Testimony). AARP witness Binz (now Nancy Brockway) also generally agrees. Exh. 750, p. 5, l. 11-15 (AARP witness Ronald J. Binz's Direct Testimony dated Dec. 29, 2006). OPC witness Kind and Staff witness Warren Wood do not really focus on such criteria, but express opposition to an FAC for other reasons, discussed below.

effects of regulatory lag on non-fuel components of the Company's cost of service by increasing the likelihood of more frequent rate cases? The Company respectfully submits that the answer to all of those questions is "no."

It simply makes no sense to believe that the Legislature, in enacting SB 179, did so with the assumption that the two largest Missouri electric utilities (with far more than one-half of the state's investor-owned utility customers) could not utilize an FAC. Yet when stripped to its essence, that is largely the argument made by FAC opponents in this case.[35] Nor would it make sense for this Commission to take that stance, given that nearly 90% of utilities in states with similar regulatory structures to that employed in Missouri, and that also have a heavy reliance on coal-fired generation (just like AmerenUE), utilize FACs.[36] The reason FACs make sense for those utilities, and for AmerenUE, is because fuel costs are significant, volatile, and are largely outside the control of utilities, including those utilities who have wisely invested in large quantities of coal-fired and nuclear baseload generation.

C. <u>Fuel and Purchased Power Costs are Undeniably Large in Relation to AmerenUE's Total Costs</u>.

The first criterion under discussion is whether the FPP costs are large. No one argues that FPP costs of over $600 million, or approximately 44% of AmerenUE's total O & M costs,[37] is not a large cost – indeed, it is the largest single operating cost item for AmerenUE. The known and expected increases (more than **____** million over the next four years) are large as well. Consequently, "criterion (1)" clearly is met.

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[35] The Company would suggest that this argument is largely a smokescreen for a wider, philosophical opposition to FACs in general. *See, e.g.* OPC's opposition to Aquila's FAC request in Case No. ER-2007-0004, and the striking similarity of OPC witness Trippensee's testimony in that case to his testimony in the Company's rate case, even though it is clear that Aquila's generation mix is far different than AmerenUE's. The Commission can take official notice of OPC's position in the Aquila case, and the Company hereby requests that the Commission do so.

[36] Exh. 20, Sch. MJL-4-1 (Lyons Feb. 5 Rebuttal). These utilities also have low rates – indeed, 22 of 25 utilities in non-restructured states (other than Missouri) with FACs also have comparatively low rates, demonstrating that FACs are not inconsistent with overall low rates. Exh. 20, Sch. MJL-4-1.

[37] Exh. 133 (Accounting Schedule 9).

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D. Market Prices for Fuel and Purchased Power Are Beyond AmerenUE's Control.

The second and third criteria deal with control and volatility. As with the first criterion, no one can seriously argue that market prices for coal, coal transportation, nuclear fuel, gas and oil, or energy, are significantly controlled by AmerenUE, though some parties assert that AmerenUE has some limited control over such costs. An examination of the facts relating to the degree of control AmerenUE could exert over its FPP costs demonstrates that these large costs are indeed largely beyond AmerenUE's control.

To support their contention that AmerenUE can control its fuel costs, FAC opponents note that AmerenUE pools its coal purchases with other Ameren affiliates, has a staff of people working in fuel procurement, and is a large coal buyer. This observation, while correct, certainly does not prove that AmerenUE can control coal prices. This alleged control over coal prices is difficult to reconcile with the fact that AmerenUE recently experienced (from 2006 to 2007) a more than **___** million increase in coal and coal transportation costs.[38] This alleged control over coal prices is equally difficult to reconcile with the fact that AmerenUE is facing nearly **___** million of already known coal and coal transportation cost increases in just the next two years with double-digit or near double-digit percentage increases to follow in the next two years after that. Moreover, do FAC opponents seriously contend that AmerenUE can control the cost of power, the cost of SO2 emission allowances, or the market for diesel fuel, which has a significant impact on coal transportation costs?[39] The answer clearly is that AmerenUE cannot significantly control these costs; neither can it control the market prices for power that it faces in both its off-system purchases and sales.

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[38] Exh. 16, p. 7, l. 17-24; p. 8, l. 1-3; p. 10, l. 9-14 (Neff Feb. 5 Rebuttal)

[39] Indeed, diesel fuel riders are approximately **___** of coal transportation costs (*see* Fn. 123, *infra*), and are expected to become an increasingly significant part of the overall transportation rates in the years to come. Tr. p. 949, l. 1-11 (Mr. Neff); As Mr. Neff also explained, diesel fuel surcharges add approximately **___** million of fuel cost uncertainty. Tr. p. 917, l. 7 to p. 918, l. 1 (Mr. Neff).

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Nonetheless, AmerenUE does what it can to manage its total FPP costs. The Commission read Mr. Neff's testimony, and most Commissioners were present for most of his testimony at the evidentiary hearings. The Commission should recognize that Mr. Neff is a competent manager who does a very good job of procuring coal supplies for AmerenUE, and indeed, no party has questioned that fact. But Mr. Neff's competence does not translate into an ability on the part of AmerenUE to magically "control" national and international commodity markets, any more than any other utility can. AmerenUE is fully exposed to market conditions when it buys fuel to power its plants, and it is a price taker, not a price maker.

Mr. Neff explained this at the evidentiary hearings. First, he explained that the coal spot (i.e., market) price is a proxy for what the Company's future contract prices will be.[40] This of course means that as market prices change, so will the Company's coal costs, and since the Company does not control the market price of coal, it cannot control its coal costs.

And while Public Counsel Mills and State attorney Micheel in particular made a heroic effort to suggest that Mr. Neff has a crack staff of coal buyers who, in their view, apparently can control AmerenUE's coal costs, Mr. Neff specifically testified that while his department has eight full-time employees (who manage coal supplies for not just AmerenUE, but all Ameren Corporation subsidiaries with generation), only *two* of these employees actually buy coal for all the Ameren generating affiliates.[41] The point is that AmerenUE cannot "control" its fuel costs;[42] it must buy coal in addition to coal it procures under its long-term contracts and sign new contracts when existing contracts expire, both of which expose AmerenUE to significant uncertainty and volatility in fuel markets, as Mr. Neff also explained:

[40] Tr. p. 914, l. 12-14 (Mr. Neff).
[41] Tr. p. 957, l. 10-19.
[42] Tr. p. 957, l. 21-25; p. 958, l. 1 – 3. Tr. p. 905, l. 16- 19 (Mr. Neff). *See also* Tr. p. 958, l. 1-12 (Mr. Neff); Tr. p. 486, l. 7-13; p. 616, l. 2-7 (Mr. Lyons).

> We can't elect to just stop buying when prices are high. We need to continue purchasing because we don't know if the prices are going to go down or if they're going to go higher yet.[43]

Mr. Neff is the only witness who testified in this proceeding who is in any way involved in purchasing fuel, and he has decades of experience in fuel procurement. As a consequence, his testimony on this subject is entitled to substantially more weight than the speculation of other witnesses and attorneys who are not and have never been involved in these markets. The facts in this record demonstrate that even coal and related transportation costs are subject to market forces (not within management's control), meaning the second generally accepted criterion indicating that an FAC is warranted has been satisfied. In addition, AmerenUE also faces significant uncontrollable costs in nuclear fuel, natural gas, and power markets.

E. <u>AmerenUE's FPP Costs Are Also Volatile</u>.

The third criterion relates to the presence or lack of volatility in FPP costs. Mr. Neff's testimony specifically establishes the volatility inherent in today's coal markets. For example, the price of PRB coal, which AmerenUE uses almost exclusively, has just over the past two to three years ranged in price from $6 per ton to $22 per ton.[44] Over an approximately five and one-half year period (March 2001 to December 2006), PRB coal prices varied from 20 to 30 percent in just a few months, with volatility spiking above 30% twelve times, above 50% four times, and over 80% one time.[45] Mr. Neff also documents similar volatility in most of the other commodities (oil, natural gas) the Company relies upon to fuel its generation.[46]

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[43] Tr. p. 905, l. 16-19 (Mr. Neff).

[44] Exh. 16, p. 2, l. 2-4 (Neff Feb 5 Rebuttal). Substantial volatility also existed just a few years ago (in 2000, 2001) as well. Tr. p. 925, l. 21-23; Exh. 16, p. 3, l. 3 – 7 (Chart – Neff Feb. 5 Rebuttal).

[45] *Id.* p. 3, l. 3-14.

[46] *Id.* p. 4, l. 1 to p. 6, l. 5.

It is an undisputed fact that commodity markets have seen substantial changes in the past few years, and the factors driving those changes have not gone away.[47] These changes have led to increasing costs for energy-related commodities, and increased volatility. One example cited by Mr. Neff is the influence of international market forces, most notably the recent awakening of a sleeping industrial giant -- China. Such forces are driving the increase in coal prices, and other market factors are expected to continue to contribute to the volatility and upward pressure on coal prices.[48]

Mr. Neff perhaps summed up the volatility he is seeing, and expects to see, in coal markets best during the evidentiary hearings when he was discussing with Commissioner Gaw attempts to hedge some of the Company's coal costs in an effort to dampen (but not eliminate) some of the volatility in the coal markets:

> Q. *** And is there anything in particular about the market today that makes you think that this is a good time to wait or a good time to – buy?
>
> A. We've seen some fundamental shift in the market since about 2004 or 2005. We've been talking about these price graphs in my testimony. And you can see that there's been some dramatic run ups not only in Powder River Basin, but all the basins. The coal market has gotten more complex. It's kind of a global market. China will do things like pull their exports out of the market. That will increase the exports out of the eastern United States which will shift western coal on the eastern part of the United States. It's a very dynamic market and really becoming more of a global market.[49]

The cost of the commodity itself is only a part of the story, however. Coal transportation makes up more than one-half of the delivered price of coal to the Company's plants. Those markets are also becoming increasingly volatile due to fundamental changes in the marketplace:

> Q. *** On the transportation side, tell me about the contract link again, if you would ….

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[47] *Id.* p. 6, l. 6 to p. 7, l. 3.
[48] *Id.* p. 6, l. 13-16.
[49] Tr. p. 935, l. 21 to p. 936, l. 9.

A. Well, the – the rail transportation market house [sic] has also undergone some transformations since roughly 2004. The railroad up to that time had excess capacity, and they competed for business. ** **[50]

Those who oppose an FAC for AmerenUE brush off the largely uncontrollable aspects of these national and international markets by suggesting that AmerenUE can simply hedge its coal and transportation costs. However, hedging only dampens volatility, and then only in the short term; hedging does not eliminate volatility and it does not reduce overall fuel costs. As Mr. Neff explains, while coal costs are largely hedged ** [51] **[52]

Assuming a coal burn in each of those years equal to the coal burn for 2007 (approximately 22 million tons[53]), and assuming a subsequent rate case concludes in June 2011, as required by SB 179, there remain approximately **30** million tons of coal that are currently unhedged through the time at which the required next rate case would conclude.[54] Given the volatility that has been observed in the coal markets, even a 30% of 50% swing in coal prices, not unlike swings seen in recent years as discussed above, could move the Company's annual

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[50] *Id.* p. 937, l. 19 to p. 938, l. 12.
[51] *Id.* p. 931, l. 15 – 22.
[52] Tr. p. 945, l. 19-20.
[53] Exh. 14, p. 2, l. 19-20 (Neff Direct Testimony).
[54] Exh. 14, p. 2, l. 19-20 (Neff Direct). ** .**

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coal commodity costs by **___** million to **___** million, up or down.[55] Moreover, the Company's recently effective transportation contracts have three-year terms and therefore expire at the end of 2009, fully 18 months before such a rate case would be concluded. Substantial price swings related to cumulative coal transportation costs – in fact price swings that could far exceed the cost of the commodity itself (recall that approximately 60% of the delivered price of coal is coal transportation[56])—could also impact AmerenUE's delivered coal costs by tens of millions of dollars before new rates would be set.

This coal and coal transportation price volatility doesn't take into account the volatility surrounding diesel fuel surcharges, which are now a feature of all of the Company's coal transportation contracts, and for which hedges are currently in place for just 2007,[57] and also does not take into account the effect on the delivered price of coal of changing SO2 emissions allowance prices, which can also be quite volatile. Coal transportation-related diesel fuel costs alone account for approximately **___** million of test year fuel costs.[58] Consequently, just a 30% to 50% swing in diesel prices would thus mean that fuel costs could be an additional **___** million to **___** million higher or lower.

This volatility in coal and coal-related prices also does not take into account gas and oil costs and purchased power costs, which can be even more volatile.[59] And the nuclear fuel markets are also undergoing changes that have created more volatility and have seen increasing prices.[60]

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[55] **___**

[56] Tr. p. 948, l. 20-25; p. 949, l. 1-8 (Mr. Neff).

[57] Tr. p. 903, l. 8-9 (Mr. Neff).

[58] Tr. p. 949, l. 4-5 (Mr. Neff).

[59] Tr. p. 761, l. 10-23 (Mr. Lyons)

[60] Exh. 17, p. 3, l. 8-15 (AmerenUE witness Randall Irwin's Rebuttal); Tr. p. 470, l. 5 – 10 (Mr. Baxter).

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In summary, while AmerenUE employs an effective hedging program that: (1) mitigates the risk that AmerenUE might not have the coal it needs if overall coal demands increase because of, for example, abnormally hot weather and higher than normal loads; and (2) dampens (but does not eliminate) volatility,[61] at any given time, AmerenUE continues to have substantial, unhedged positions with respect to the commodities it needs to fuel its plants, meaning that AmerenUE will be affected by the volatility inherent in the markets for those commodities.

Consequently, the third criterion – volatility – is also clearly present in AmerenUE's case, and also supports adoption of an FAC for AmerenUE.

F. <u>FPP Cost Changes Can Substantially Affect AmerenUE's ROE</u>.

The last criterion deals with the potential of changing FPP costs to have a material effect on the Company's ROE.[62] A $50 million movement in fuel and purchased power costs would move AmerenUE's ROE by approximately 100 basis points.[63] The already-known coal and coal transportation cost increases occurring by the end of 2009 will have an impact of approximately **___** basis points, all else being equal.[64] It is fully expected that as much as an additional approximately **___** million of cost increases will be incurred through 2010[65] – which equates to another more than **___** basis points.

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[61] Tr. p. 894, l. 3-7 (Mr. Neff).
[62] This criterion is essentially reflected in SB 179 itself, which indicates that the Commission is to make a finding when approving an FAC that the FAC is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity. This factor is addressed in Exh. 19, Sch. MJL-2-2.
[63] For example, see (Mr. Neff) Exh. 247. A comparison of Columns C and D shows that a 50 basis point difference in allowed ROE translates to a $24 million difference in revenue requirement.
[64] *See* Fn. 22, *supra.* The Company agrees that not everything will remain precisely equal; indeed, the Company doesn't expect other offsetting cost decreases elsewhere in its cost structure. Tr. p. 667, l. 18-25; p. 668, l. 1-2, Tr. p. 619, l. 11-16. Loads may grow, producing some additional revenues, but the Company's load growth is quite modest, and serving it is not without cost. Off-system sales may or may not increase – e.g., as load grows, less generation is available to sell off-system, and in any event, if off-system sales do increase the additional revenues will be netted against fuel and purchased power costs to the benefit of ratepayers. Given the kind of numbers at issue, it appears beyond reasonable debate that fuel and purchased power cost increases have the potential to substantially move the Company's ROE, further justifying adoption of an FAC for AmerenUE.
[65] *Id*. As outlined in footnote 22, considering coal expenses were already $548 million for the test year ending June 2006 and the fact that coal costs increased **___** million in 2007 over the test year levels, the forecast total increases of coal costs amount approximately **___** million in 2008, an additional **___** million in 2009, and

As discussed below, there is no evidence of other offsetting cost reductions, and indeed there is substantial evidence of a rising operating cost environment at AmerenUE. Because of the effects of regulatory lag, the Company will not have a sufficient opportunity to earn a fair ROE in the absence of an FAC.

G. The Opponents' Other Arguments Against an FAC Are Meritless.

1. Administrative Complexity.

Three parties, principally OPC, the State, and AARP, essentially argue that adoption of an FAC will simply overwhelm the Commission's resources.[66] But can OPC, the State and AARP seriously contend that parties in this state are any less capable of dealing with an FAC than are parties (including commissions and staffs) in 27 out of 29 other similarly regulated states?

For example, the State and OPC engaged in a great deal of cross-examination relating to the number of coal contracts at issue, and coal invoices, purchased power transactions, etc., all in an effort to make it appear that prudence and true-up audits of FACs would be next-to-impossible to perform. But as Mr. Trippensee admitted, OPC does not itself conduct audits of actual cost adjustment filings by the gas utilities under this Commission's jurisdiction that make such filings under the gas utilities' version of an FAC, the purchased gas adjustment (PGA) clause.[67] Moreover, the entity likely to conduct audits of FAC filings – the Staff – has expressed no opposition to an FAC based upon some supposedly excessive administrative burden or supposed inability to properly administer the FAC.

Indeed, the Commission, in adopting its FAC rules (a process moderated through over a dozen workshops led by Staff member Warren Wood), included extensive surveillance and

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yet another **____** million in 2010, which would leave 2010 costs approximately **____** million above 2007 levels.

[66] *See, e.g.*, OPC witness Russell Trippensee's Feb. 5, 2007 Rebuttal Testimony.

[67] Tr. p. 1048, l. 1-10.

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reporting requirements. These requirements will provide the Staff and other parties, on an ongoing, monthly basis, a great deal of information which can be used to monitor the operation of the FAC and FPP costs generally, and which will facilitate and simplify the audits required by SB 179. In other words, a periodic FAC adjustment filing, true-up, or prudence review won't be a start-from-scratch exercise where all of the data is being seen for the very first time by those charged with auditing the filings. In fact, that was the purpose of the filing and reporting requirements in the FAC rules: "One of the goals [of the FAC rules] was to make more readily available the information to perform such an assessment [prudence reviews]."[68] Rather Staff and other parties will have an ongoing picture of the Company's FPP costs and off-system sales revenues that will facilitate its periodic reviews.

The suggestion that AmerenUE's off-system sales into the MISO markets will need to be audited, on a transaction-specific basis, borders on the specious as well. The MISO markets are, by their nature, transparent wholesale markets. What Staff and others are going to look at are the dispatch of the Company's plants, plant heat rates (discussed later), and plant outages, all to ensure that the Company is operating its plants efficiently. In this regard, it is apparent that Staff is comfortable that the monitoring and efficiency testing employed by AmerenUE will allow it to do just that, as evidenced by Mr. Wood's hearing testimony on that point.[69]

At bottom, it would seem axiomatic that the Commission would not have gone to the trouble of adopting extensive SB 179 rules had the Commission believed that it should reject FAC requests merely because prudence and true-up audits would need to occur. It would seem axiomatic that the Legislature would not have mandated that such audits occur, if an FAC could be rejected simply because of the fact that such audits must occur. It would further seem that if

[68] Tr. p. 999, l. 16-17 (Mr. Wood).
[69] Tr. p. 1003, l. 1-6; 14-15; p. 1004, l. 4-11, 18-22; p. 1005, l. 21-25.

administering an FAC was an inefficient, overly burdensome process, commissions in nearly every other state would have avoided them.

In just the past few years, this Commission has seen multiple rate cases from three of its four electric utilities, and now AmerenUE, and fuel costs were a substantial factor in most of those rate cases. The numbers for AmerenUE are clear – many tens of millions of dollars of fuel cost increases are very likely to occur in just the next few years, and those kinds of numbers, as discussed above, are clearly large enough to have significant impacts on the Company's ROE. Under those circumstances, in the absence of an FAC, it would be virtually certain that AmerenUE would need to file rate cases more frequently than mandated by SB 179. Is it reasonable to believe that the process reflected in an 11-month rate case process – literally boxes and boxes of testimony, thousands of data requests, depositions, weeks of hearings, hundreds if not thousands of pages of briefs – is less administratively burdensome and preferable to an FAC? Are more frequent rate cases with hearing rooms full of lawyers and consultants preferable to addressing this large, largely uncontrollable, and volatile expense item through periodic adjustments that better match these costs to the rates customers actually pay? The Company respectfully submits that an FAC is a more sensible and efficient process for dealing with these kinds of large, largely uncontrollable, and volatile costs, as most other jurisdictions have found.

Some parties answer, in the case of AmerenUE, that just because AmerenUE has not had to file rate cases on a frequent basis in the past it may not have to do so in the future. As discussed by Mr. Neff, the markets have undergone some fundamental shifts in the last few years, and the conditions that have created a great deal of volatility and a rising cost environment have simply not gone away. The evidence in this case is that without an FAC, AmerenUE will likely have to file another rate case in the near term because of rising fuel and purchased power costs.[70] As Mr. Lyons testified, "* * * fuel is the largest single operating cost that we have, and I'm aware that the cost [sic] are escalating significantly over the next couple of years. And I'm not aware of other costs in our business which are declining which would produce a – an offset to those costs."[71]

2. Alleged Mitigation of FPP Costs by Off-System Sales.

The Staff takes a different tack in opposing the Company's FAC request. Staff makes the flawed argument, based upon what Staff admits is less than a complete analysis, that off-system sales revenues will "partially mitigate" AmerenUE's rising fuel costs, from which Staff draws the conclusion that the Company does not need an FAC. Staff's inadequately supported theory fails to hold water.

Staff witness Wood sponsors Staff's opposition to AmerenUE's FAC request. His position – which is conclusory and based entirely on an admittedly incomplete analysis conducted by Dr. Michael Proctor – is as follows: "AmerenUE does not need an FAC or IEC since its revenue opportunities in off-system sales mitigate much of its fuel price risk."[72] Mr. Wood, however, conducted no independent analysis to support his statement.[73] Moreover, even Dr. Proctor admits that since he did not conduct a complete analysis, he cannot say whether Mr. Wood's statement, quoted above, is *even true.*[74] Indeed, it is clear that Mr. Wood far overstated any conclusion that Dr. Proctor reached, as evidenced by Dr. Proctor's own testimony, which at the very most "brings into question AmerenUE's need for a fuel adjustment

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[70] Tr. p. 875, l. 7-19 (AmerenUE witness John W. Mayo); Exh. 21, p. 8, l. 4-9 (Lyons Surrebuttal); Tr. p. 772, l. 4-7 (Mr. Lyons).
[71] Tr. p. 619, l. 11-16 (Mr. Lyons).
[72] Exh. 245, p. 1, l. 27-28 (Wood Rebuttal, FAC, Feb. 5, 2007).
[73] Tr. p. 1495, l. 10-12.
[74] Tr. p. 1495, l. 16-19. The Company does not suggest that Mr. Wood intends to testify untruthfully, but rather, that Mr. Wood and Staff in general have placed far too much reliance on the incomplete and flawed, overly narrow "analysis" conducted by Dr. Proctor.

clause."[75] Indeed, as AmerenUE witness Shawn Schukar points out in his surrebuttal testimony, Dr. Proctor admits that there are many shortcomings to his analysis, which Dr. Proctor himself calls only an "illustration." The illustrative nature and shortcomings of Dr. Proctor's analysis clearly indicate that Mr. Wood's overstated conclusion is inappropriate and wrong.[76]

That Dr. Proctor's analysis is incomplete is apparent from his hearing testimony as well:

Q. * * * There were a number of variables you didn't include in that analysis, correct?

A. I'm not sure. Give me an example.

Q. Take a look at your rebuttal testimony.

A. I didn't include load variations. I didn't include variations relating to outages to be specific. * * *

Q. And in order to do a complete analysis, you would need to do that, correct?

A. Correct."[77]

As AmerenUE witness Shawn Schukar explains in his surrebuttal testimony, the incompleteness of Dr. Proctor's analysis is made even more clear when one considers the fact that Staff's conclusion that off-system sales eliminate the need for an FAC is based exclusively on two very extreme and unrealistic cases. Those two extreme cases were a "high-high-high" case, where it was assumed that coal prices, energy prices, and gas prices were all high at the same time, and a "low-low-low" case, where it was assumed that coal prices, energy prices, and gas prices were all low at the same time.[78] That is, these two scenarios assumed that AmerenUE's coal costs, market prices for coal, gas prices, and energy prices all move in lock-step.

[75] Exh. 228, p. 27, l. 19; p. 28, l. 1 (Proctor Rebuttal Testimony).
[76] Exh. 32, p. 8, l. 20-24; p. 9, l. 1-8.
[77] Tr. p. 1492, l. 25; p. 1493, l. 1-5, 9-11 (Dr. Proctor).
[78] Tr. p. 1493, l. 20-25; p. 1494, l. 1-7 (Dr. Proctor).

Mr. Schukar, in his surrebuttal testimony, ran 27 (not two) combinations of coal, energy, and gas prices, and his analysis indicates that there is *no netting effect at all* in 22 of those 27 cases (i.e., in 22 out of 27 cases, off-system sales revenues do nothing to offset increased fuel costs).[79] Of the five cases where some netting effect appeared, fuel risk was reduced by 20% or more in only two of those cases.[80] Dr. Proctor's so-called "netting effect" solely depends on coal, energy, and gas prices moving in lock-step with each other, a scenario that is very unlikely given past experience and current fuel price forecasts. For example, the United States Department of Energy expects coal prices to continue their recent price increase in the future, but expects natural gas prices to fall – hardly a lock-step relationship.[81] Moreover, as shown in Schedules SES-14 and SES-15, coal dispatch prices may rise, while energy prices and gas prices may fall – again, hardly a lock-step relationship.[82] Dr. Proctor himself admits that AmerenUE's coal contract prices "vary somewhat" from market prices for coal, and that coal dispatch prices include substantial (and volatile) SO2 costs not accounted for in the coal commodity market.[83]

Dr. Proctor also admitted that even if AmerenUE fuel costs and power prices were moving in the same direction, off-system sales profits may not outpace fuel cost increases, in which event there will not be any offset to rising fuel costs:

"Q. Coal prices go up 10 percent. It's not always the case that energy prices are going to go up more than 10 percent?

A. Okay. If you're – if you're going to put it on a percentage basis, then I understand it. I understand the question.

Q. And the answer to the question is?

A. Sure. Yeah

[79] Exh. 32, Sch. SES-17-2 (AmerenUE witness Shawn E. Schukar's Surrebuttal Testimony).
[80] *Id.*
[81] *Id.*, p. 15, l. 14-23; Sch. SES-15-1 and SES-15-3.
[82] *Id.*
[83] *Id.*, p. 12, l. 13-22.

* * *

Q. All right. And if it doesn't, if an increase in energy prices is not enough to overcome the increase in the gas [sic – should read coal] price increase, then margins are not going to go up, right?

A. Certainly.

Q. In fact, margins could be less under the scenario, could they not?

A. They could be if you got into a case where your coal costs went up but the price for energy didn't go up –

Q. Didn't go up enough to cover the increase?

A. Didn't go up enough to cover the increase, then yeah, your profit margins are going to drop."[84]

And Dr. Proctor gave a similar answer in response to a question from Commissioner Murray:

"A. Well, see, I did not say and my testimony and is not that the profits that your're going to get back from those [off-system] sales will more than offset fuel cost. I never said that, and I never calculated that."[85]

It simply defies common sense to assume that whenever AmerenUE's own fuel costs increase power prices would always increase even faster. Power prices are determined by market conditions that are largely independent from AmerenUE's own costs and, during peak hours, are mostly driven by natural gas prices. There is simply no reason to believe power prices would always increase faster than AmerenUE's fuel costs such that OSS profits could offset some of these cost increases.

Finally, at best (and his incomplete and flawed analysis fails to support even this conclusion), the most Dr. Proctor could say was that there may be a "partial mitigation effect," i.e., that off-system sales revenues might partially mitigate AmerenUE's fuel cost increases in some cases.[86] Indeed, Dr. Proctor's analysis, which is too incomplete in any event, is largely if

[84] Tr. p. 1492, l. 2-14 (Dr. Proctor).
[85] Tr. p. 1497, l. 7-10 (Dr. Proctor).
[86] Tr. p. 1502, l. 22-25 (Dr. Proctor).

not totally irrelevant at this point given that AmerenUE is proposing an FAC that nets off-system sales revenues against fuel costs, because the reason Dr. Proctor did this analysis in the first place was due to the Company's earlier proposal to address off-system sales separately from the FAC.[87] That separation no longer exists. Mr. Wood himself seemed to at least soften his stance against an FAC when he testified at the evidentiary hearings that "I would indicate that the surrebuttal position [AmerenUE's proposed FAC that nets off-system sales against fuel costs in the FAC] is a step better from where it was in the earlier – the two positions taken earlier by the company."[88] The fact is that Staff's main argument against a fuel adjustment clause, the offsetting effect of OSS profits, is fundamentally flawed – which also invalidates Staff's conclusion that AmerenUE does not need an FAC. Staff's position is also inconsistent with the fact that the large majority of other coal-based utilities in non-restructured states are operating with an FAC.

3. Other Miscellaneous FAC-Related Issues.

a. Heat Rate Testing.

As mentioned briefly above, Staff, in Mr. Wood's rebuttal testimony, raised an issue about the adequacy of the heat rate or efficiency testing conducted by AmerenUE at its generating units. Efficiency testing of this type measures plant performance, and as Mr. Wood indicated, is important to ensure that the utility continues to operate and maintain its plants in an efficient manner with an FAC. AmerenUE's Vice President of Power Operations, Mark Birk, addressed this issue in his surrebuttal testimony and at the evidentiary hearings. The bottom line is that it is not clear there remains any disagreement between the Staff and the Company on this issue. As Mr. Wood put it: "Really, you know, I think if you look at Mr. Birk's surrebuttal and

[87] Tr. p. 1510, l. 23-25 (Dr. Proctor).
[88] Tr. p. 1001, l. 5-8 (Mr. Wood).

you look at the four steps we said would be necessary for unit operation for a utility, for the fuel adjustment clause, I really think we're really very close to one another."[89]

The Company currently employs a real-time monitoring system at its major units, called the ETA PRO system,[90] and also uses an Efficiency Deviation Factor (EDF) that will be re-established according to each true-up period.[91] The Company believes this is superior to a one-point-in-time heat rate test as apparently outlined in Mr. Wood's rebuttal testimony,[92] and it would appear Staff does not disagree with the efficacy of the EDF, coupled with the Company's ETA PRO system.

Consequently, the Company believes this issue is resolved simply because the Company can continue its current heat rate efficiency testing, and can complete installation of performance monitoring systems and the use of EDFs at the Company's combustion turbine units.[93] If there are any remaining minor disagreements about this issue, they can be brought to the Commission for resolution as part of the implementation of the FAC. This issue should not preclude the Commission from approving an FAC in this case.

b. Adjustments to Fuel Costs Through the FAC.

The State, in particular, has stated that if an FAC is granted, it needs to accommodate an adjustment relating to the failure of Taum Sauk to ensure that the Company's net fuel costs are not increased as a result of the absence of Taum Sauk from the generating fleet. A similar issue has been raised in relation to the EEInc. issue, if some kind of adjustment were ordered by the Commission relating to EEInc.[94]

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[89] Tr. p. 1005, l. 21-25 (Mr. Wood).
[90] Tr. p. 964, l. 1-7 (Mr. Birk).
[91] Tr. p. 971, l. 4-25; p. 972, l. 1-2; p. 974, l. 2 – 25; p. 975, l. 1-6 (Mr. Birk).
[92] Tr. p. 976, l. 21-25; p. 977, l. 1-13 (Mr. Birk).
[93] Tr. p. 972, l. 17-25 (Mr. Birk).
[94] Tr. p. 1070, l. 16-20. For the reasons discussed later in this Brief, any such adjustment is improper and unlawful.

With respect to Taum Sauk, the Company agrees – indeed has always agreed – that an adjustment to net fuel costs must be made in the FAC to account for the loss of the Taum Sauk plant. Mr. Lyons very directly and succinctly addressed this issue in his rebuttal testimony.[95] Simply stated, the Company has run its production cost model and determined that the test year value of the lost Taum Sauk generation is $21.4 million annually.[96] Of that sum, $7.9 million comprises fuel cost savings, and the remaining $13.5 million comprises lost off-system sales margins.[97] The Commission can order an adjustment, to be flowed through the "R" factor built into the FAC tariff (currently reflected in Exhibit 104) equal to the lump-sum value of the lost Taum Sauk generation determined by the Commission in this case. Alternatively, if this "test year value" approach is not acceptable to the Commission, the Company could run its production cost model each year, "true-up" the value of Taum Sauk to the test year value in the context of annual FAC true-ups, and include an appropriate adjustment in the Company's FAC rates.[98] Again, this issue should not preclude the Commission from adopting an FAC.

c. <u>Miscellaneous FAC Tariff Items</u>.

i. OPC Witness Trippensee.

OPC witness Russell Trippensee raised a few miscellaneous issues which the Company addresses briefly here.

First, Mr. Trippensee objects to more than one FAC adjustment per year. He admits, however, that the Commission's FAC rules contemplate up to four adjustments per year (the Company is proposing only three adjustments).[99] Moreover, of the 27 other non-restructured

[95] Exh. 20, p. 30, l. 22-23; p. 31, l. 1-18 (Lyons Rebuttal).
[96] Exh. 20, p. 32, l. 1-8 (Lyons Rebuttal).
[97] *Id.* p. 32, l. 3-5.
[98] *Id.*, p. 32, l. 18-23; p. 33, l. 1-28; p. 34, l. 1-16. Though improper, any EEInc. adjustment if ordered could also be addressed using the "R" factor.
[99] Tr. p. 1031, l. 20-25 (Mr. Trippensee).

states (out of 29) that use FACs, 21 allow monthly or quarterly adjustments.[100] PGAs in Missouri allow multiple filings each year as well. Notably, of the four other non-restructured states (Missouri is the 5th) that require that FAC adjustments be based on historical, as opposed to projected costs, all four of those states allow *monthly* FAC adjustments, apparently to reduce the lag between the underlying changes in fuel costs and the recovery of those costs.[101] If only one adjustment per year were in place for AmerenUE, and given the Commission's requirement that historical costs be used, there would be an extremely significant lag in cost recovery (and higher interest costs), credit ratings agencies would have concerns about the lack of timely recovery, and a poor matching of actual costs and rates (which would fail to send timely price signals to customers) would exist.[102] Simply stated, there is no legitimate reason to build up a year's worth of fuel cost changes which may lead to larger annual rate increases or decreases, with larger interest deferrals, as opposed to making more regular periodic adjustments throughout the year.[103]

Second, Mr. Trippensee objects to the inclusion of ash disposal costs and revenues as a fuel expense. Ash is treated as a component of fuel under the Uniform System of Accounts USOA.[104] Ash is bought and sold in an established and volatile market not under the control of AmerenUE.[105] Mr. Trippensee opposes inclusion of ash costs (net of revenues), even though he expressed almost total ignorance about ash disposal costs and markets. For example, he did not know that ash disposal costs (net of revenues) are a direct function of the amount of coal that is

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[100] Exh. 21, Sch. MJL-5 (Lyons' Surrebuttal).
[101] Exh. 21, p. 15, l. 6-7 (Lyons Surrebuttal).
[102] *Id.* l. 7-11.
[103] Mr. Trippensee had also criticized the recovery or return of under- or over-recoveries over a subsequent quarter, as opposed to over a subsequent 12-month period. The Company's revised FAC proposal, reflected in Exhibit 104 and Mr. Lyons's surrebuttal testimony, calls for recoveries over a subsequent 12-month period, and consequently addresses Mr. Trippensee's concern.
[104] Exh. 19, Sch. MJL-2-4; MJL-2-5 (Lyons Supplemental Direct).
[105] Exh. 21, p. 17, l. 18-20 (Lyons Surrebuttal).

burned, or that there is a volatile market (which the Company does not control) for ash.[106] Mr. Trippensee's position on this issue is, consequently, uninformed and without merit.

Third, Mr. Trippensee objects to the inclusion of Company-owned railcar repair and depreciation costs as a fuel expense in the FAC. Mr. Trippensee's position on this is directly contrary to Staff's position, as expressed by Staff witness John Cassidy, and is directly contrary to the Company's position. These costs are also treated as fuel costs under the USOA,[107] and they are precisely the same kinds of costs the railroads charge the Company as part of their transportation rates for delivering coal to the Company's plants.[108] Indeed, Mr. Trippensee does not dispute this, and in fact agrees that if it is more economic for the Company to own rail cars (as opposed to using railroad equipment), the Company should do so.[109] Why then is it completely proper to pay these costs to the railroads and recover them as a fuel expense, but not proper (in Mr. Trippensee's view) to do precisely the same thing when the Company makes an economic decision (to use its own rail cars) that lowers overall coal transportation costs and thus fuel expense? The answer: Mr. Trippensee's position makes no sense, and these costs should be included in fuel expense and recovered under the FAC.

Mr. Trippensee proposes two other changes to the proposed FAC; that is, he would treat hedging costs differently under an FAC than the treatment given them by the Commission under the PGA, and he would exclude sales of excess fuel from operation of the FAC.

With respect to hedging costs, hedging costs are part and parcel of prudent fuel cost management, and excluding them from the FAC creates the wrong incentives for the utility.

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[106] Exh. 21, p. 17, l. 14-20 (Lyons Surrebuttal); Tr. p. 1042, l. 11-25; p. 1043, l. 1-17 (Mr. Trippensee).
[107] Exh. 19, Sch. MJL-2-5 (Lyons Supplemental Direct).
[108] Exh. 21, p. 17, l. 21-24; p. 18, l. 1-7 (Lyons Surrebuttal).
[109] Tr. p. 1044, l. 23-25; p. 1045, l. 1-3 (Mr. Trippensee).

This is why they are included in the PGA mechanism,[110] and should be included in the FAC.[111] Mr. Trippensee has provided no sound rationale for treating these costs differently in the FAC, and the Commission should not do so.

With respect to fuel inventory sales revenues, proper fuel management sometimes requires sales of excess fuel to manage or reduce inventories. Those sales are reflected in the USOA's fuel accounts, and may be caused by unexpected variations (e.g., due to weather) in coal or gas usage. These sales occur in national/international markets, they are a normal part of managing the fuel portfolio and they should be in included in fuel expense in the FAC.[112]

ii. Other Miscellaneous FAC Tariff Items.

There exists one last set of miscellaneous FAC tariff items which are addressed below. Exhibit 104 is a specimen tariff sheet that details the operation of AmerenUE's proposed FAC. The parties were given the opportunity to provide additional direct testimony about Exhibit 104 during the evidentiary hearings, and to cross-examine Mr. Lyons regarding its operation. A final FAC tariff, if an FAC is approved by the Commission, would be filed along with the re-filing of all of the other necessary tariff sheets to implement the Commission's Report and Order in this case. While the parties had only limited questions about Exhibit 104, a few minor suggestions were made during the evidentiary hearings, and the Company wants to address each of those here.

First, Mr. Kind suggested that Exhibit 104 be clarified to ensure that revenues relating to hedging, not just hedging costs, should be included in the FAC.[113] The Company agrees.

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[110] *See, e.g.*, AmerenUE Gas Tariff Sheets 22 - 32, of which the Commission can take administrative notice under Section 536.070(6), RSMo..
[111] Tr. p. 1046, l. 14-19 (Mr. Trippensee).
[112] Exh. 21, p. 18. l. 17-23 (Lyons Surrebuttal).
[113] Tr. p. 1661, l. 17 (Office of Public Counsel witness Ryan Kind).

Second, Mr. Kind also suggested a slight modification to the definition of off-system sales in Exhibit 104 (Tr. p. 1662, l. 2-7). The Company also agrees with this suggestion.

Third, MIEC witness James Dauphinais had one suggestion, that is, that a clarification relating to MISO costs should be made to Exhibit 104, and the Company agrees with the clarification as suggested.[114]

Finally, there was a typographical error in the sharing grid, and the Company sharing portion in the last row should be 0%.[115]

This tariff is the product of a great deal of work on the Company's part, and a good faith effort to incorporate the suggestions of the other parties. George Swogger testified on behalf of Noranda that the tariff language was "good enough" to satisfy Noranda.[116] With the minor changes proposed herein, the Commission should approve the proposed tariff.[117]

II. Revenue Requirement Issues.

A. Off-system Sales – Sharing of Net Fuel Cost Savings.

As outlined in Mr. Lyons' surrebuttal testimony[118] and as reflected in Exhibit 104, the Company has proposed for the Commission's consideration a sharing mechanism that creates additional incentives for the Company to lower its overall FPP costs, by either lowering FPP costs or increasing off-system sales (OSS) margins. The sharing mechanism would operate as follows:

- The Commission will establish a fixed, test year or "base" level of net fuel and purchased power costs to include in base rates – this will be the sum of fuel and purchased power costs, less off-system sales revenues;[119] and

[114] Tr. p. 1666, l. 17-21 (Missouri Industrial Energy Consumers witness Jim Dauphinais).
[115] Tr. p. 1663, l. 25 to p. 1664, l. 2 (Mr. Dauphinais). The Company agrees that there was a typographical error, and that the percentage should be 0%.
[116] Tr. p. 1158, l. 21-22 (Mr. Swogger).
[117] The Company again also reiterates its commitment, if its FAC proposal is approved, to fund, with shareholder monies, $2.6 million per year in energy efficiency and low-income programs, as outlined by Mr. Baxter. Exh. 3, p. 7, l. 7-23.
[118] Exh. 21, p. 20-22 (Lyons Surrebuttal).
[119] Tr. p. 686, l. 11-13; p. 688, l. 15-24 (Mr. Lyons).

- Under the FAC, there will be four true-up years (per the Commission's FAC rules, and Exhibit 104), and under the sharing mechanism, net fuel costs will be determined for each true-up year. If (and only if) the Company is able to more than offset the already-known fuel cost increases such that net fuel costs for a given true-up year are below the base level set as described in the first bullet above, the sharing mechanism operates. Mr. Lyons described an example during the evidentiary hearings where net fuel costs for a true-up year decreased by $30 million because OSS revenues increased by $30 million. In that example, the Company shared in $9.5 million of the $30 million of net fuel cost savings, while customers shared in $20.5 million, and also benefited from AmerenUE's ability to offset the already-known fuel costs increases.[120]

The last point is important because the sharing mechanism was designed to operate only when net fuel costs decrease, as opposed to increasing, which ensures customers receive significant benefits before the Company receives any sharing amounts, due to the known fuel cost increases that will occur over the next few years. In effect, in this rising fuel cost environment, any sharing mechanism that shared equally increases and decreases in net fuel costs relative to a base amount determined using historic costs would in practice be asymmetrical (and inherently unfair to the Company) because the base level of fuel costs against which sharing would be applied would not increase to take into account these fuel cost increases. Another approach would have been to re-set the base level of fuel costs each year, but that would require more complicated analyses and requires the adoption (by agreement or litigation) of various assumptions (e.g., what the off-system sales volumes will be, what energy prices will apply to those volumes, etc.). Given that it is undisputed that fuel costs are rising over the next several years, and the Commission's rules requiring use of historic costs, it makes sense to simply apply the sharing grid to only net decreases.

As the testimony in this case indicates, an FAC, which avoids more frequent rate cases necessitated simply to recover rising fuel costs, preserves the benefits of regulatory lag for the

[120] Tr. p. 572, l. 2 to p. 574, l. 18 (Mr. Lyons).

roughly two-thirds of AmerenUE costs that are unaffected by an FAC.[121] As discussed above, FACs in Missouri must be the subject of mandatory, regular prudence reviews and annual true-up proceedings. Efficiency testing (as discussed above) is required respecting the operation of the Company's generating units. A mandatory rate case must be concluded within four years, during which all of the utility's costs and revenues will again be examined, and base rates will be re-set. These requirements all continue to give the Company strong incentives to minimize its fuel and purchased power costs, and to maximize off-system sales, which under the Company's proposal, serve to reduce overall FPP costs.

The sharing mechanism proposed by the Company enhances these incentives.[122] The proposed sharing mechanism is also fair, in that it caps the "upside" available to the Company at approximately a modest 100 basis points of ROE, without capping the upside available to customers. As the example discussed above indicates, just a $30 million reduction in net fuel costs would mean that (1) customers benefit fully from AmerenUE's ability to offset the already-known increases in fuel costs; and (2) customers additionally obtain more than twice the benefits realized by the Company for any further reduction below the base level of net fuel costs. This is a fair and logical incentive mechanism which will work to the benefit of ratepayers, and which the Commission should adopt.

1. The Appropriate Level of Off-System Sales Margins.

a. Establishing the "Right" Level is Very Difficult.

There is little question that setting the "right" level of off-system sales margins for inclusion in the Company's revenue requirement is an imprecise exercise. Numerous factors, many of which are driven by market forces not within the control of the utility, affect what those

[121] *See, e.g.*, Tr. p. 860, l. 13 to p. 861, l. 16 (AmerenUE witness Dr. John Mayo); Tr. p. 1099, l. 20-24 (State of Missouri witness Michael Brosch).

[122] Tr. p. 774, l. 1-10 (Mr. Lyons); Tr. p. 822, l. 8-20 (Dr. Mayo).

off-system sales margins will be. Fuel costs can vary, as discussed above, for a variety of reasons (due to changes in commodity and transportation contracts; market price variations in the SO2 emissions allowance market; variations in the cost of diesel fuel, which comprises approximately 20% of the Company's coal transportation costs,[123] which in turn comprise approximately 60% of delivered coal costs; changes in the price of electricity, both on-peak and off-peak; unit availability variations; and load variations, among other things). Mr. Schukar discusses how these variables (and the uncertainty surrounding them) can affect off-system sales margins at pages 18 to 20 of his direct testimony.[124] He also addressed the specific risks of plant availability and native load uncertainty further at pages 21 to 23 in his surrebuttal testimony.[125]

Several non-Company witnesses agree that it is difficult to precisely set the "right" number for off-system sales margins. Dr. Proctor agrees that neither the Company nor Staff will be "right" about the level of off-system sales margins that will actually be realized over the next three to four years;[126] Mr. Brubaker agrees,[127] as does Mr. Brosch.[128]

And there is also general agreement that if the Company can enhance its earnings by more than offsetting fuel cost increases with more off-system sales margins, it is being given a proper incentive.[129] It is also obvious that where off-system sales margins are to be netted against FPP costs, as suggested by other parties and as now proposed by the Company, it is important that the level of off-system sales margins that is built into rates not be set so high as to effectively preclude the Company from ever being able to gain any benefit from any incentive

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[123] Tr. p. 948, l. 19 to p. 949, l. 8 (Mr. Neff) (Coal transportation costs are approximately **___** million for the test year, with approximately **___** million (19.9% of that figure) in diesel surcharge costs.
[124] Exh. 28, p. 20, l. 7-1 (Schukar Direct).
[125] Exh. 32, p. 21, l. 19-23; p. 22, l. 1-24; p. 23, l. 1-17 (Schukar Surrebuttal).
[126] Exh. 100, p. 37, l. 3-12 (Proctor Deposition).
[127] Exh. 700, p. 14, l. 20-21 (Brubaker Direct Testimony, Dec. 15, 2006).
[128] Exh. 502, p. 32, l. 18-20; p. 33, l. 1-3 (Brosch Direct Testimony on Fuel Adjustment Clause).
[129] *See, e.g.*, Tr. p. 1136, l. 3-15 (Mr. Brubaker).

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mechanism that is implemented. Indeed, Dr. Proctor specifically agrees that the Commission should not set a base level of off-system sales margins that is too high.[130]

Of the parties making a specific recommendation on a base level of off-system sales margins to be set in this case, only one party has taken a completely outlying approach, and that is the State.[131] State witness Brosch has improperly reached forward to use a single item from AmerenUE's 2007 budget (OSS margins), without considering any other forward-looking cost items, and without considering the fact that a one-year, forward looking budget is not based on normalized conditions, such as normalized unit availabilities and energy prices. We discuss the inappropriateness of the State's position on this issue in more detail below.

The other parties with specific recommendations regarding off-system sales margins are the Staff, MIEC and the Company. Staff recommends a normalized level of off-system sales margins of $241.3 million.[132] However, Dr. Proctor's testimony is clear that this figure did not take into account congestion and losses that we know exist, and he recognizes that the energy prices which he used to set off-system sales margins are overstated. He further already recognized that a 2% discount to his prices would be a reasonable correction of this problem, which would bring Staff's off-system sales margins recommendation down to approximately $233 million.[133] As discussed below, there are other underlying problems with Dr. Proctor's calculation of energy prices (and consequently, his calculation of off-system sales margins), which indicate that an appropriate normalized level of off-system sales margins is substantially lower than even Staff's adjusted level of $233 million.

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[130] Exh. 100, p. 29, l. 17-20 (Proctor Deposition).

[131] OPC also apparently now seeks to rely upon a budgeted number (at least according to Staff's Reconciliation), although they have provided no testimony in support of use of one budget item in setting off-system sales margins.

[132] Tr. p. 1018, l. 10-13 (Dr. Proctor).

[133] Tr. p. 1562, l. 2-4, Tr. p. 1481, l. 1-8; Exh. 110. (Dr. Proctor recognizes that his energy prices, which he in turn uses to calculate off-system sales margins, are overstated because they fail to take congestion and losses into account; the second citation shows Proctor's confirmation of the $233 million).

Mr. Dauphinais, for MIEC, indicates that if the Commission is going to set a normalized level of off-system sales margins, it should set that level at not less than $211.2 million (versus the Company's recommended level of $202.5 million).[134] This is based upon an average energy price of $38.54/MWh,[135] which is quite close to the Company's recommended energy price for determining off-system sales margins of $38.04/MWh. It appears that one of the key reasons Mr. Dauphinais suggests this as a "minimum" level is his view that there remains "uncertainty" about the ability to model off-system sales volumes and margins given changes in the marketplace over the last couple of years. This leads Mr. Dauphinais to speculate about whether the volumes of off-system sales modeled by both the Company and the Staff (which are quite close, as noted below) are reasonable. However, Mr. Dauphinais made no attempt to model off-system sales volumes or margins, and he is unable to cite any specific flaw or shortcoming in either the Company's or the Staff's models, which produced virtually identical results in terms of volumes. In fact, the off-system sales margin results sponsored by the Staff and the Company only vary because the Staff and the Company have different positions on two of the *inputs* into the model: normal levels of natural gas prices and electricity prices after the inception of MISO Day 2 energy markets. As Dr. Proctor testified:

> Q * * * the model results now agree, with one exception, and that is the input of energy prices the company and the Staff don't agree on, correct?
>
> A. Input of fuel price for natural gas and the inputs of off-system – I'm sorry – spot market prices for electricity, yes.
>
> Q. Those are the only two, to your knowledge, points of disagreement between the modeling between the company and the Staff at this point; is that correct?
>
> A. That's my understanding, yes.
> * * ***

[134] Tr. p. 1641, l. 8-11 (Mr. Dauphinais).
[135] Exh. 712, Sch. JRD-Surrebuttal-1 (Dauphinais Surrebuttal).

And Dr. Proctor also agrees that modeling off-system sales is necessary because normalized loads, prices, unit availabilities, etc. need to be used.[136] As Dr. Proctor explained, reliance on historical off-system sales volume levels when the Joint Dispatch Agreement (JDA) was in effect was not possible because conditions have changed. What Staff found is that system energy transfers (i.e., between AmerenUE and its affiliates under the JDA – these were in effect "off-system sales" between affiliates) were at a higher volume, but at a lower price, whereas going forward, volumes will be lower, but the price will be higher.[137] Under the JDA, AmerenUE may have run its cheaper incremental cost generation and engaged in a system energy transfer to an affiliate rather than running that affiliate's higher cost generation (which means AmerenUE was providing more volumes – more "off-system sales"). After the JDA ended, the affiliate may observe that market prices are higher in its territory than its incremental costs, and the affiliate may run its own generation rather than receiving a system energy transfer from AmerenUE (which means AmerenUE would provide less volume – less "off-system sales").[138]

The Staff's modeling results reflect off-system sales volumes of 9.75 million MWhs, and the Company's model results are almost identical.[139] No one has leveled any specific or even general criticism at these modeling results; at most, MIEC has speculated that there may be "uncertainty" about AmerenUE's ability to model its system. The bottom line is that the only two parties who took into account the key variables that must be considered to determine a reasonably accurate, normalized level of off-system sales margins – the Staff and the Company – agree on what those off-system sales volumes will be, and have only a disagreement on price.

[136] Tr. p. 1452, l. 24 to p. 1454, l. 21; p. 1547, l. 10-25 (Dr. Proctor).
[137] Tr. p. 1549, l. 8-15 (Dr. Proctor).
[138] Tr. p. 1550, l. 19-23 (Dr. Proctor).
[139] Tr. p. 1452, l. 11-13 (Dr. Proctor).

b. Staff's Recommended Off-system Sales Margin is Demonstratively Too High.

Where then, does that leave the Commission in determining a reasonable, normalized level of off-system sales margins? It means that the evidence from everyone but the State and OPC (as noted above), is that the appropriate level is in a range from $202.5 million to $241.2 million (and, really $233 million, as discussed above since Dr. Proctor identified a 2% downward adjustment to his prices to account for congestion and losses). And as was clear from the evidentiary hearings, even that $233 million is too high, and is largely unsupportable, because it is based upon a normalized gas price (which in turn drives the on-peak energy price at which off-system sales margins are determined) that is too high.

Why is the underlying gas price too high? Principally because Dr. Proctor, though professing in his direct testimony and on the witness stand that one *must* remove the effects of the 2005 hurricanes to arrive at a normalized gas price, *failed* to remove those effects from his analyses. As the Commission is aware, in the late Summer of 2005, a series of hurricanes, including the now infamous Hurricane Katrina, caused catastrophic damage along the Gulf Coast, including to the natural gas production industry. This created dramatic price shocks in the gas industry for many months thereafter – no one disputes this.

When Staff filed its direct case in December, 2006, Dr. Proctor recommended use of a normal gas price of $7/MMBtu, based upon a 12-month average of gas prices from December 2005 through November 2006.[140] In surrebuttal, Dr. Proctor changed his methodology and instead relied upon an average of gas prices from 2004 through 2006, and interestingly, still came up with a $7/MMBtu gas price.[141]

[140] Tr. p. 1457, l. 1-11 (Dr. Proctor).
[141] Tr. p. 1457, l. 12-18 (Dr. Proctor).

Yet Dr. Proctor admits that both of those averages include extremely high prices that were artificially inflated by the 2005 hurricane-related disruptions to gas supplies, which means that Dr. Proctor did not do what he said he must do: remove the effects of those hurricanes.[142] Consequently, Dr. Proctor's use of a $7/MMBtu gas price is simply overstated because it includes artificially high gas prices that should have been removed, but which were not removed.

For example, in his initial 12-month average from December 2005 through November 2006, Dr. Proctor included gas prices for December 2005, which were extremely high – approximately *$13*.[143] As Mr. Schukar showed, removing the December 2005 price and calculating the 12-month average for January through December 2006 yields an average gas price of $6.58.[144] Then Dr. Proctor used a 2004-2006 average that did not just include hurricane-inflated gas prices from *one* month in 2005, but from *several* months.[145] And while Dr. Proctor tried to resist agreeing to this point, it is clear that gas prices in early 2006 (which are also included in Dr. Proctor's averages) were also still somewhat elevated due to the lingering effects of the hurricanes.[146]

Even Dr. Proctor's own schedules to his surrebuttal testimony, Schedules 2.3 and 3.3, demonstrate that a $7 gas price appears abnormal, largely because it includes artificially high gas prices due to the 2005 hurricanes. For example, Schedule 2.3 contains the average gas price for 48 months, and it is apparent from reviewing it that in only approximately 25% of those months were prices above $7. In many of those months, gas prices were far below $7, and nearly all of the prices that were above $7 were obviously that high due to the 2005 hurricanes. A similar picture is painted by Schedule 3.3 (*see also* Exhibit 107), which shows "de-trended" gas prices

[142] Tr. p. 1457, l. 21 to p. 1461, l. 2 (Dr. Proctor).
[143] Tr. p. 1465, l. 14 to p. 1466, l. 13 (Dr. Proctor); Exh. 229, Sch. 2.3 (Proctor Surrebuttal).
[144] Exh. 30, p 21, l. 11-13 (Schukar Rebuttal, Jan. 31, 2007.
[145] Prices of $11, 12 and nearly $13/mmbtu. Tr. P. 1471, l. 17-22; Exh. 229, Sch. 2.3 (Proctor Surrebuttal).
[146] Tr. p. 1462, l. 5 to p. 1464, l. 11 (Dr. Proctor).

for January through December (using four years of data). Only two of those months have a de-trended gas price of over $7, both of which fall within months Dr. Proctor admits were affected significantly by the 2005 hurricanes. Indeed, the average of those de-trended prices is $6.63,[147] just $.05 higher than the 2006 average gas price of $6.58 that the Company recommends the Commission use as the normal gas price to calculate on-peak energy prices for use in pricing off-system sales.

The bottom line is that it is a clear stretch to use a $7 gas price because a $7 gas price continues to be substantially and artificially inflated by the impact of the 2005 hurricanes. Indeed, there is no evidence that suggests that the Company's use of a $6.58 gas price, which is based upon a 12-month average for 2006 (and which therefore removes the extremely high gas prices in December 2005), is unreasonable. Arguably, even use of a 2006 average gas price could overstate a normal gas price level given that it appears (as discussed earlier) that the hurricanes' effects may have lingered into early 2006, but in any event, a 2006 average gas price is far more supportable than the hurricane-distorted gas price used by the Staff.

c. Dr. Proctor's Corrected Schukar Prices Also Show that Staff's Recommended Off-system Sales Margins Are Too High.

In his surrebuttal testimony, Dr. Proctor "corrected" the modeling performed by Mr. Schukar. Mr. Schukar had used daily data designed to capture seasonal differences in the relationship between gas prices and on-peak energy prices. Dr. Proctor had used a "12-month moving average" that did not capture those seasonal differences. Dr. Proctor stated that he did not believe that "going to a monthly type model to estimate the annual relationships between variables is necessary."[148] However, Mr. Schukar's testimony demonstrates that there is a significant seasonal differential in the relationship between gas prices and on-peak energy

[147] Tr. p. 1468, l. 16-25 (Dr. Proctor).
[148] Exh. 229, p. 27, l. 1-3 (Proctor Surrebuttal).

prices.[149] This makes intuitive sense. Relatively inefficient gas peaking units are "on the margin" (i.e., the market price of energy is driven by those units) more in the Summer months than in the non-Summer months, as one would expect, given that it is primarily in the Summer when those units run at all. Why do they typically run only in the Summer? Because that is when regional loads are highest. In other months, the market price for on-peak power is more likely determined by more efficient combined-cycle natural gas plants or a combination of coal and natural gas plants.

Dr. Proctor does not directly dispute any of these facts, but simply dismisses use of monthly data that would capture the seasonal differences as being "unnecessary" and opts to use what he characterizes as his "simpler" approach that he says is "sufficient for the task."[150] Being "sufficient" is hardly an endorsement that it is the best or most accurate method to capture those seasonal differences.

Nevertheless, Dr. Proctor did provide an estimate of (by "correcting" Mr. Schukar's analysis) what his OSS margin would be if one takes those seasonal differences into account and also using electricity prices which properly reflect congestion and losses (as opposed to using a simple 2% approximate correction). Indeed, as discussed in detail at the evidentiary hearings and as depicted on Exhibit 110, which Dr. Proctor acknowledged was accurately calculated,[151] Dr. Proctor's own seasonal estimates, which he describes as corrections to Mr. Schukar's approach, reduce Staff's off-system sales margin calculation by $20 million, even using his artificially inflated $7 gas level.[152]

However, this use of a $7 inflated gas price overstates Staff's off-system sales margins by a significant amount. As shown on Exhibit 109, which is one of Dr. Proctor's workpapers, use

[149] Exh. 30, p. 14, l. 17 to p. 15, l. 8 (Schukar Rebuttal, Jan. 31, 2007).
[150] Exh. 229, p. 27, l. 6-7 (Proctor Surrebuttal).
[151] Tr. p. 1489, l. 4-11 (Dr. Proctor).
[152] Tr. p. 1483, l. 5 to p. 1484, l. 19 (Dr. Proctor).

of an average gas price for 2006 (the $6.58 price recommended by the Company), in Proctor's seasonal model yields an on-peak energy price of $48.66/MWh, which is $5.85/MWh lower than used by Staff in its off-system sales modeling.[153] Substituting this on-peak price correction into the methodology described above reduces Staff's off-system sales margins to approximately $207 million.[154]

The following table summarizes the above-discussed off-system sales margins:

Party	***Off-System Sales Margin Recommendation***	***After Accounting for Losses and Congestion***	***Proctor Seasonal Model Using $7 Gas Price***	***Proctor Seasonal Model Using $6.58 Gas Price***
Company	*$202.5 million*	*Already accounted for in the $202.5 million*	*N/a*	*N/a.*
Staff	*$241.2 million*	*$233 million (using Proctor's 2% approximate correction)*	*$221 million (accounts for losses and congestion)*	*$207 million (accounts for losses and congestion)*
MIEC	*$211.2 million*	*Already accounted for in the $211.2 million*	*N/a*	*N/a*

At bottom, there are significant, evidentiary-based reasons to believe that a normalized level of off-system sales is in the $202.5 million to $207 million range, and not near the $241 million that Staff recommends.

[153] Tr. p. 1476, l. 18 (Dr. Proctor).
[154] Tr. p. 1488, l. 1-8 (Dr. Proctor). The fact that a seasonal determination of normalized on-peak power prices as a function of normalized natural gas prices reduces estimated OSS margins also makes intuitive sense. The effect of gas prices on on-peak power prices is most pronounced during the Summer as discussed above. This, of course, is also the season during which AmerenUE has the least generating capacity available to make off system sales. This means more of the Company's off-system sales are during the lower-priced non-summer periods, which reduces OSS margins. In other words, by averaging the effect of natural gas prices over a full 12 month period, Dr. Proctor overstated on-peak prices during the non-Summer periods in which the Company makes proportionally more of its off-system sales.

d. Grabbing One Budgeted Item is Inappropriate For Setting Rates Based Upon an Historic Test Year.

As noted above, the State, and apparently OPC, making no attempt whatsoever to determine a *normalized* level of off-system sales margins, suggest that the Commission should use AmerenUE's 2007 budget for off-system sales and (1) should simply ignore the fact that loads and unit availability can vary greatly from year-to-year, and that energy prices are volatile and can vary greatly as well,[155] and (2) should ignore the fact that in Missouri rates are set based upon historic test years, not based upon one snapshot budget item from one year.

Loads do vary from year to year, due to weather, due to how the economy may be doing, and due, for example, to the addition or loss of a major customer.[156] Plant availability varies considerably as well – the point is, off-system sales vary from year-to-year, and the only way to arrive at a normalized level of off-system sales to rely upon in setting rates is to model those sales.[157]

The State[158] entirely ignores these undisputed facts, although Mr. Brosch acknowledges a number of shortcomings in the use of one budget item from just one year. For example, he agrees that it is *likely* that there are outage events in 2007 that differ from normalized outages. But, in recommending use of the 2007 budget, it is clear Mr. Brosch did little or no due diligence to see if it was representative of normal conditions. Prior to making his recommendation, he did not know, for example, of the lack of assumed outages in the budget at all at the Company's Labadie[159] and Meramec plants.[160] Mr. Brosch also did not know, or perhaps did not care, that the energy prices used for the budget were the forward curve for 2007 at the Cinergy Hub as it

[155] Tr. p. 1120, l. 19-21 (Mr. Brosch).
[156] Tr. p. 1452, l. 24 to p. 1453, l. 7 (Dr. Proctor).
[157] Tr. p. 1453, l. 23 to p. 1454, l. 21 (Dr. Proctor).
[158] OPC does as well, but simply provided no evidence of any kind or nature on this issue, so the Company will focus on the State's "sponsorship" of using the budgeted number herein.
[159] Labadie is by far the Company's largest power plant (nominally rated at 2,460 MW of output), and Meramec is also a large (940 MW) plant. Exh. 89, Schedule TSL-1-8.
[160] Tr. p. 1120, l. 14 to p. 1121, l. 2 (Mr. Brosch).

existed on just one day (January 2, 2007), though forward curves vary greatly throughout the year.[161]

Not only is a forward price from one day unreliable, but a Cinergy price overstates the revenues AmerenUE could actually realize at its generators. For the 12 months ending January 31, 2007, Cinergy prices were, on average, $1.63 per MWh higher than the price that AmerenUE actually realized at its generators, making Cinergy prices inappropriate for use in setting off-system sales margins.[162] Indeed, reliance on a Cinergy price would at best be a stretch goal, inappropriate for setting rates.[163]

More fundamentally, budgets are not used to set rates in Missouri, and it is certainly inappropriate to determine the revenue requirement based on a historic test year, but then reach forward and grab a single budgeted item without considering the budget for any of the other costs and revenues that may exist during the budget period. Perhaps Mr. Brubaker best explained why budgets are not used in Missouri to set rates:

> "A. Well, Commissioner [Appling], I guess I would say first that as consumers we're interested in having adequate and reliable power at reasonable rates, fundamentally. And the way we get there, I think, is the test-year process * * * that we have in Missouri and other cost-of-service regulated states where we look at expenses, the investments, cost of capital, revenue offsets for things like off-system sales in kind of a *coordinated, synchronized basis,* you know, the test year concept . . ." (emphasis added).[164]

More specifically, Mr. Brubaker questioned using a forward test year (which Mr. Brosch is in effect doing as to this one item alone):

> "A. Now, you can look out into the future, but, you know, we have a test year and the test year is kind of a coordinated look. I have trouble sometimes with the long-

[161] Tr. p. 199, l. 10, to p. 200, l. 2 (Mr. Baxter); Tr. p. 1610, l. 12 – 17 ("Q. Probably slightly, but isn't it a fact that throughout the year forward price curves can change a lot? A. Absolutely. Q. They can go way up, they can go way down, they move all over the place, correct" A. That's correct.") (Dr. Proctor).
[162] Exh. 32, p. 6, l. 16-20 (Schukar Surrebuttal).
[163] *Id.* l. 20-24. Indeed, Mr. Schukar, who runs Ameren Energy which markets all of AmerenUE's off-system sales, did not supply the numbers upon which the 2007 budget is based, and the energy prices that underlie that budget do not reflect Mr. Schukar's view of what energy prices will be. Tr. p. 1431, l. 6-12.
[164] Tr. p. 399, l. 24-25; p. 400, l. 1-10 (Mr. Brubaker).

> term forward view because we don't have a new – we don't have a future test year. We don't have specific investments or expense projections for 2007, '8 or '9 to look at. We have a historic test year with adjustments for known and measurable changes, and as long as we keep those in kind of a synchronized fashion, if we up expenses we need to look at the revenue facts of that, the investment and depreciation, I think that's the best you can do. And I think that's all you need to do.[165]

Mr. Brosch also admitted he had reached out and grabbed just one budget item, while ignoring others:

> Q. Okay. Mr. Brosch, is it your position that we should use budgets with regard to other items in setting rates? Should we use budgeted amounts, for example, to reflect that amount of rate base that's included in base rates?
>
> A. No. The convention here is to use historical actual data adjusted for known and measurable changes whenever possible.
>
> Q. So that's a no. So it's a no to my question?
>
> A. It's generally it's a no. However –
>
> Q. It is just a yes or no question. Should we use budgeted?
>
> A. Generally no.
>
> Q. Okay. Thank you. Should we use budgeted medical expenses in setting rates?
>
> A. Probably not.
>
> Q. Should we use budgeted wages in setting rates?
>
> A. Sometimes it's necessary to do so.
>
> Q. Would you support the use of a budgeted test year in the state of Missouri?
>
> A. Not under the present framework of regulation, no.

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[165] Tr. p. 401, l. 7-19 (Mr. Brubaker).

2. Sharing Net Fuel Cost Savings.

a. The Company's Proposal to Share Net Fuel Cost Savings Provides Incentives that Benefit Customers.

To address concerns that were expressed by many of the parties in this case, the Company (as discussed above) proposes to net all off-system sales revenues against FPP expenses in the FAC. To enhance the incentives the Company has to continue to minimize net fuel costs (i.e., FPP costs net of off-system sales margins), the Company has proposed a net fuel cost savings sharing mechanism, described in detail in Mr. Lyons' surrebuttal testimony (Exhibit 21)[166] and in Exhibit 104. The operation of the sharing mechanism was discussed above.

Other sharing mechanisms have been discussed by other witnesses in this case, and they all essentially share both increases and decreases in off-system sales or net fuel costs around the normalized base amount, in a manner that *appears to be* (but is not) symmetrical.[167] The reason these mechanisms are not symmetrical, and indeed are unfair, is because they virtually ensure that the Company will fail to recover its prudently incurred fuel costs.[168] This is the case due to the known fuel cost increases that the Company is facing together with growing loads, which would reduce volumes available to sell off-system. As Mr. Schukar explained in his Feb. 5, 2007 testimony, the already-known fuel cost increases demonstrate that the proposed sharing mechanisms are inherently biased. This asymmetry created by rising fuel costs would unfairly and unreasonably impose costs on shareholders. In fact, Mr. Brubaker and AARP witness Nancy Brockway, for example, both acknowledge that the sharing approaches they advocate, when fuel

[166] Exh. 21, p. 21, l. 17-21; p. 22, Chart, l. 2-16 (Lyons Surrebuttal Testimony).
[167] Mr. Brubaker and Ms. Brockway (who adopted Mr. Binz's testimony) discuss a sharing mechanism with deadbands, while Mr. Higgens discusses a sharing mechanism without deadbands. See Schukar rebuttal testimony (Jan. 2007) (Exh. 30) at pp. 33-41 and Schukar rebuttal Feb. 2007 at pp. 4-8 for a discussion of and response to these alternative sharing mechanisms. All of these sharing mechanisms would similarly share increases and decreases of costs relative to the normalized base level.
[168] Exh. 31, p. 4, l. 21 to p. 6, l. 17 (Schukar Rebuttal, Feb. 5, 2007).

costs rise, will result in shareholders bearing those increased fuel costs within the deadband.[169] This is true even though the fuel costs are prudently incurred and used to produce power for customers' benefit.

By contrast, AmerenUE's net fuel cost sharing mechanism is fair because AmerenUE must offset every dollar of these significant and known fuel cost increases before AmerenUE shares in any net fuel cost savings at all. Indeed, every dollar of known fuel cost increases that AmerenUE is able to offset accrues to the benefit of customers. Plus, unlike past regulatory treatment of off-system sales, once AmerenUE is able to overcome known fuel cost increases to lower net fuel and purchased power costs below the base set by the Commission in this case, customers additionally receive a share of the savings – in fact potentially a very large share that could be more than twice the Company's share.

b. AARP's Proposals Are Inappropriate.

If a fuel adjustment clause were to be implemented, Ms. Brockway recommended that only 50% of any fuel cost changes should be passed through in rates.[170] This is entirely inadequate, inconsistent with the regulatory mainstream which allows for the full pass-through of fuel costs, and insufficient to address credit concerns in Missouri. It also is entirely inconsistent with Ms. Brockway's primary recommendation that the FAC should be used to flow through 100% of off-system sales margins to customers.[171]

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[169] Tr. p. 1139, l. 20 to p. 1140, l. 12 (Mr. Brubaker). Although Mr. Brubaker argues that the utility will simply control or lower other, non-fuel costs if its fuel costs increase (which he tries to argue makes his fixed off-system sales level with deadbands fair), he has presented no evidence at all suggesting that AmerenUE would be able to lower such other costs. In fact, there is no evidence in the record at all of any known operating cost decreases expected in the future at AmerenUE, and there is substantial evidence that costs are rising. *See, e.g.*, Exh. 1 (Baxter Direct); Consequently, the fact remains: Mr. Brubaker's deadband in effect precludes recovery of legitimately and prudently incurred fuel costs in the rising fuel cost environment that exists today and that is expected to exist for several years to come. Tr. p. 3840, l. 18-23; p 3841, l. 24 to p. 3842, l. 11 (AARP witness Nancy Brockway).
[170] Tr. p. 3825, l. 2-15 (Ms. Brockway).
[171] Tr. p. 3825, l. 16 to p. 3826, l. 1 (Ms. Brockway).

As Mr. Lyons showed in his surrebuttal testimony,[172] of the states that utilize fuel adjustment clauses, five states have implemented some form of sharing mechanisms, and in four of these five states rates and fuel riders are set on projected fuel costs, not historical fuel costs as required in Missouri. But because Missouri relies on historic fuel costs to set the base, Ms. Brockway's proposal would automatically result in under-recovery of half of all already known and projected further increases in AmerenUE fuel costs. As Mr. Lyons also explained on page 23 of his surrebuttal testimony,[173] in light of already known and substantial fuel cost increases, the sharing mechanism proposed by Ms. Brockway (or the similar mechanism proposed by Mr. Brubaker) in combination with setting an FAC based on *historic* (rather than projected) costs creates an inherent and substantial cost recovery bias that would lead to more frequent rate cases, provides poor efficiency incentives, and raises credit concerns. In other words, Ms. Brockway's proposed sharing grid would eliminate the primary benefits of a fuel adjustment clause and still require AmerenUE to file more frequent rate cases to recover these rising fuel costs. Mr. Lyons also explains succinctly on pages 23-24 of his surrebuttal testimony[174] why such a mechanism would fail to address the cost recovery-related concerns by credit rating agencies:

> Q. Why would these sharing grids raise credit concerns?
>
> A. Given the recent increases and volatility of fuel and purchase power costs, credit rating agencies have been very concerned about credit implications of fuel and purchased power cost recovery risks, particularly for the few utilities who do not have access to an FAC or for utilities with only a "weak" adjustment mechanism. Characteristics of "weak" adjustment mechanisms include mechanisms that allow only the partial pass-through of fuel costs (e.g., passthrough mechanisms with dead bands), that are based on historical fuel prices (as opposed to projected prices), that allow for only infrequent rate adjustments, that accumulate significant deferrals, or that cap FAC rates or accumulated deferrals. By virtue of being based on historic costs rather than projected costs, the Missouri FAC rules already are viewed as relatively unfavorable by credit rating agencies. The proposal AmerenUE has presented includes further customer protection measures

[172] Exh. 21, Sch, MJL-5 (Lyons Surrebuttal).
[173] Exh. 21.
[174] Exh. 21.

> -- the 4% annual cap on average retail rate increases, recovery extended from 3 to a 12-month period, and only three adjustments per year -- that further weaken the FAC from a credit perspective. If Messrs. Brubaker's or Binz's [now Ms. Brockway's] specific proposals were implemented, the FAC design would raise quite severe credit concerns, given the deadband in their proposals and the fact that the sharing grids would not allow for full recovery of AmerenUE's already known increases of fuel costs. Approval of such a weak and unusual FAC would be poor regulatory policy because it would fail to fully achieve a key benefit of FACs; that is, the strengthening of the relative credit quality of Missouri utilities and the resultant lower borrowing costs (which translates into lower revenue requirement) that allow utilities to finance the large capital investments necessary to continue to provide safe and adequate electric service at reasonable rates. [footnote omitted]

Ms. Brockway also adopted Mr. Binz's recommendation to implement a sharing grid similar to one that was recently implemented in Wyoming. However, despite the fact that she agreed that the details of a particular mechanism are important,[175] during cross-examination it became clear that Ms. Brockway has only read Mr. Binz's testimony and the tariff sheet attached to his testimony, but was otherwise entirely unfamiliar with the circumstances under which the Wyoming sharing mechanism was implemented, and completely failed to do any proper due diligence in recommending it.[176] For example, Ms. Brockway did not consider that the Wyoming mechanism was part of a settlement and stipulation and that it allowed the utility (PacifiCorp) to file a rate case just approximately one year after the approval of the stipulation, at which point the utility could then use a *forward-looking* test year.[177] Other important features of the Wyoming mechanism are that (1) the parties to the stipulation agreed that they would support a *forecasted test year that extends 20 months* past the date of actual historic data in the utility's next rate filing;[178] (2) the stipulation implemented an allowed return on equity of 10.75%;[179] and (3) the adopted mechanism was a temporary compromise so that the parties could continue their

[175] Tr. p. 3838, l. 5-14 (Ms. Brockway).
[176] Tr. p. 3839, l. 7-15; p. 3847, l. 12-16 (Ms. Brockway).
[177] Tr. at p. 3847, l. 12 to p. 3848, l. 6 (Ms. Brockway).
[178] Exh. 128, at ¶ 51.
[179] Exh. 128, at ¶ 55.

discussions to design a "alternative form of regulation" or "AFOR" mechanism that would take the place of several future annual litigated rate cases by establishing revenue requirement on a predetermined formula which would keep rates in line with cost of service, including fuel and power costs.[180] The Wyoming case also made clear that the fuel cost mechanism and other features of the stipulation were implemented to reduce the risk of "continuing back-to-back rate cases" given the upward pressure in rates faced by the utility. Importantly, however, the fact that PacifiCorp will be able to establish rates based on a 20-month forward looking test year is a critical distinction as setting rates based on forward looking costs avoids the inherent asymmetry and cost-recovery bias that implementation of a Wyoming-type sharing grid would create if implemented for AmerenUE, given rising fuel costs and Missouri's reliance on historic rather than projected costs.

B. Electric Energy, Inc.

1. No Imputation of Revenue as a Result of the Expiration of AmerenUE's Power Supply Agreement with EEInc. is Either Lawful or Justified.

The record now before the Commission confirms that there is no basis as a matter of law, or of simple fairness, to impute sums in the calculation of AmerenUE's revenue requirement based on the expiration of the Power Supply Agreement (PSA) between AmerenUE and EEInc. Because EEInc. will no longer sell its power to AmerenUE at a below-market, cost-based price, the other parties have proposed significant reductions in AmerenUE's revenue requirement, ranging from $75 million to $21.7 million per year for every year.[181] These parties effectively

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[180] Exh. 128, at ¶¶35, 39, 91.

[181] *See* Staff Reconciliation (OPC - $75 million); Joint Notification of Agreement on True-up (filed by Staff and AmerenUE) (Staff - $65.3 million); Exh. 852, p. 18-19, l. 4-9 (The Commercial Group witness Kevin C. Higgins' Direct Testimony) ("Scenario 1" -- $21.8 million, "Scenario 2" -- $42.1 million, "Scenario 3" -- $62.6 million). Note that these figures (*e.g.*, Staff's $65.3 million) assume in some cases energy prices for off-system sales that are too high, as discussed above. If correct energy prices were used, Staff's EEInc. adjustment would have to be reduced accordingly.

want to declare that AmerenUE's revenue was larger by these sizeable amounts than it actually was in the test year, or ever will be, and are all based upon the fiction that more off-system sales will be made at AmerenUE.

These figures do not represent off-system sales margins AmerenUE has actually received, or will ever receive. These figures do not represent any money that either AmerenUE's ratepayers ever paid to or invested in EEInc. These figures do not represent any money that AmerenUE's ratepayers ever had at risk in the operations of EEInc. (or, for that matter, of AmerenUE).

Rather, this adjustment is proposed simply to punish AmerenUE by artificially lowering its revenue requirement with phantom off-system sales margins. And what did AmerenUE supposedly do wrong to justify such a penalty? These parties claim that AmerenUE did not compel EEInc. to extend or renew an expired contract – the PSA – so that AmerenUE could still purchase power from EEInc. at a below-market price. They conclude that it was imprudent or inequitable for AmerenUE not to compel EEInc. to do this. While these parties try to justify this proposed adjustment by claiming – incorrectly – that AmerenUE's ratepayers bore some risk of EEInc.'s operations, the nub of the EEInc. issue is their fundamental premise – a premise they explicitly state – that AmerenUE *could* have compelled EEInc. to sell its power at a below market price.[182] That is, by the estimate of one of these parties, AmerenUE could have lawfully compelled a separate corporation to sell its key asset (the power that separate corporation generates) for less than half of what it is worth.[183]

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[182] Exh. 103, p. 20-21, l. 22-4 (Staff witness Robert E. Schallenberg's Deposition) (testifying to his opinion that AmerenUE had a "legal right" to continue the PSA), *id.* at p. 26, l. 17-20 (testifying that AmerenUE was to get EEInc. to sell power below market by directing "its directors to vote that way"); Exh. 852, p. 14, l. 7-9 (Higgins Direct on Fuel Adjustment Clause) ("The ability to have extended the PSA was entirely within the control of AmerenUE and its corporate affiliates.").

[183] *See* Tr. p. 2686, l. 1-16 (Mr. Brosch) (showing that EEInc.'s revenues were projected to grow from $174 million in 2005, selling at cost-based prices, to $370 million in 2006, when it began selling at market prices).

No one can deny – as this proposed adjustment illustrates – that the old, cost-based contract with EEInc. was a good deal. But the regulatory world has changed dramatically with the inauguration of a genuine wholesale market for power. As the amounts the various parties propose to impute to AmerenUE's revenue also illustrate, the move to market-based prices was a good deal for EEInc. EEInc. is not a regulated utility, but a profit-making corporation. It has no reason to sell its power below market (particularly given the current difference between today's market prices and a cost-based price). The PSA expired under its own terms. AmerenUE did not cause that contract to expire nor could it have done anything to stop it from expiring. Contrary to the premise of this proposed adjustment, AmerenUE does not have the legal right or power to now compel EEInc. to once again sell its power below market.

In sum, the EEInc. issue boils down to a legal issue. No party challenges the elementary point that AmerenUE could not have done anything wrong to justify this adjustment if it had no legal power or right to compel EEInc. to sell it power at a below-market price.[184] The merit of this adjustment hangs on this legal question.

The evidence now before the Commission after the exploration of the witnesses' positions during the hearing makes it clear that this adjustment must be rejected. There is almost no dispute between the parties concerning the relevant facts. Moreover, the other parties have offered no evidence on the relevant principles of law to create a dispute in that arena. In the end, the proposed EEInc. adjustment rests only on conclusions offered by the other parties unsupported by either the facts or the law.

[184] *See, e.g.*, Tr. p. 2675, l. 4-7 (Mr. Brosch); p. 2705, l. 19-22 (Staff witness Greg R. Meyer); p. 2786, l. 2-4 (Mr. Schallenberg).

2. The Record Before the Commission.

a. Undisputed Facts.

The following material facts have not been disputed, either because the parties did not disagree or because only evidence establishing these facts was put into evidence.

i. The Organization and Structure of EEInc.

- EEInc. is a for-profit, Illinois corporation not within the jurisdiction of this Commission.[185]
- EEInc. was formed in 1950 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.[186]
- The purpose of EEInc. was to provide the electrical power for the Federal Government's uranium enrichment plant at Paducah Kentucky.[187]
- EEInc. built a single, coal-fired power plant at Joppa, Illinois, and this plant was the only such facility by which EEInc. generated power for the Paducah Project.
- 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.[188]
- Pursuant to the express approval of the Commission, AmerenUE owns 40 percent of the stock of EEInc.[189]
- While the Bylaws of EEInc. provide a mechanism by which the Sponsoring Companies may change the percentage of the Joppa Plant's power that they have the option to purchase, no provision in the Bylaws sets prices for that power or in any way guarantees a certain price for that power.[190] That is, while each Sponsoring Company has an option to buy a certain percentage of the power generated by EEInc., the price for that power must be agreed upon by the Sponsoring Company (as the buyer) and EEInc. (as the seller). If these parties do not agree on a price, there is

[185] Exh. 37, p. 11, l. 21-23 (Moehn Surrebuttal, Feb. 5, 2007).
[186] Exh. 5, p. 5, l. 15-21 (AmerenUE witness David A. Svanda's Rebuttal Testimony); Exh. 225, p. 6, l. 11-17 (Meyer Direct).
[187] Tr. p. 2343, l. 13-16 (Mr. Moehn).
[188] Exh. 37, p. 5, l. 22-26 (Moehn Surrebuttal).
[189] Exh. 971 (Report and Order, Case No. 12,064 (1950), authorizing the initial purchase of EEInc. stock); Exh. 974 (Report and Order, Case No. 12,463 (1952), authorizing the purchase of additional shares of EEInc. stock).
[190] Tr. p. 2672, l. 16-21 (Mr Brosch); Exh. 98, p. 38-39, l. 21-7 (Kind Deposition).

no “meeting of the minds” to conclude a contract, and the Sponsoring Company would not be able to buy its percentage allocation of EEInc.’s power.

- Five of the seven members of EEInc.’s Board of Directors at the time the PSA expired also held a position in one of the Ameren companies.[191]

ii. The Relationship of AmerenUE to EEInc.

- AmerenUE’s only “ownership” interest in EEInc. consists of EEInc. stock that it purchased in the 1950s. [192]

- Only the money of AmerenUE shareholders was used to purchase the stock of EEInc.[193] That investment has never been included in AmerenUE’s cost of service or in any other way subsequently included in AmerenUE’s rates. The loss of that money invested in EEInc. was exclusively a risk of AmerenUE’s shareholders and created no risk of any kind for AmerenUE’s ratepayers.[194]

- The money AmerenUE paid for power purchased from EEInc. over the years has been included in its Missouri cost of service as a purchased power cost, and those expenses have never been criticized as being in any way imprudent.[195]

- The money of AmerenUE’s customers has never gone to EEInc. for anything other than power that AmerenUE has purchased, received, and used on their behalf.[196] AmerenUE’s customers pay for service. They are not buying the property of EEInc.[197]

- Neither AmerenUE, its shareholders, nor its ratepayers own the Joppa Plant or any other asset of EEInc.[198]

- Neither the Joppa Plant, AmerenUE’s stock in EEInc., nor any other asset of EEInc. has ever been considered or treated by the Commission as part

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[191] Tr. p. 2613-18, l. 2-9 (Mr. Naslund).
[192] Exh. 5, p. 5, l. 15-21 (Svanda Rebuttal); Exh. 225, p. 6, l. 11-17 (Meyer Direct).
[193] Tr. p. 2709, l. 14-17 (Mr. Meyer); Exh. 37, l. 27-29 (Moehn Surrebuttal).
[194] Exh. 103, p. 69, l. 5-8 (Schallenberg Deposition); Exh. 37, p. 5, l. 27-29 (Moehn Surrebuttal);
[195] Tr. p. 2469-70, l. 25-10 (Mr. Svanda); *id.* at p. 2348, l. 9-12 (Mr. Moehn); Exh. 37, p. 6, l. 27-31 (Moehn Surrebuttal).
[196] Tr. p. 2352, l. 2-7 (Mr. Moehn).
[197] Tr. p. 2676, l. 11-15 (Mr. Brosch).
[198] Tr. p. 1955, l. 22-24 (AmerenUE witness Gary Rainwater); *id.* at p. 2349, l. 9-10 (Mr. Moehn); *id.* at p. 2672, l. 22-24 (Mr. Brosch); *id.* at p. 2710, l. 6-8 (Mr. Meyer); Exh. 103, p. 69, l. 20-22 (Schallenberg Deposition).

of AmerenUE's rate base.[199] Thus the Joppa Plant is very different from a plant actually owned by AmerenUE, which is included in rate base.[200]

- AmerenUE has never behaved inconsistently with the treatment of the investment in EEInc. as an unregulated asset of its shareholders. AmerenUE has never attempted to impose any risk or cost on its customers unrelated to the purchases of power from EEInc. from which AmerenUE's ratepayers actually benefited and which were, accordingly, included in AmerenUE's cost of service by this Commission.

- Because of this difference – AmerenUE (as opposed to AmerenUE's shareholders) only had a contract to buy power from EEInc. and did not own EEInc.'s Joppa Plant – the costs of EEInc. could never have been passed on to AmerenUE's ratepayers if there was some accident at the Joppa Plant and it could not produce power.[201]

- The rates charged to AmerenUE ratepayers over the period 1954 – 2005 have never included any expenditures related to EEInc., or any other type of cost related to or incurred by EEInc., other than the expenses for power prudently purchased from EEInc. and received by AmerenUE. The only aspect of the relationship between AmerenUE and EEInc. that has ever been treated as within the jurisdiction of this Commission, or could in any way be termed "jurisdictional," because it affected AmerenUE's cost of service reflected in retail rates, was the expense of power purchased from EEInc. through long-term purchase power agreements, the last of which was the PSA.[202]

- If the relationship of AmerenUE (as opposed to that of AmerenUE's shareholders) to EEInc. over the period 1954 - 2005 had been something more than an arm's-length relationship of a buyer of power to a seller of power – that is, if AmerenUE actually owned the Joppa Plant or in some way bore a risk related to EEInc.'s assets or operations more like that of an owner; or if EEInc. could in any way be considered some sort of "regulatory asset" of AmerenUE – AmerenUE's cost of service would have been far higher than it was. For example, 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.[203]

[199] Tr. p. 1940, l. 11-13 (Mr. Rainwater); *id.* at p. 2349, l. 21-22 (Mr. Moehn); Exh. 852, p. 10, l. 13-14 (Higgins Direct); Exh. 103, p. 69, l. 13-19 (Schallenberg Deposition); Exh. 37, p. 5, l. 27-29 (Moehn Surrebuttal).
[200] Tr. p. 2349, l. 19-22 (Mr. Moehn).
[201] Tr. p. 2350, l. 9-17 (Mr. Moehn).
[202] Tr. p. 2352, l. 2-7 (Mr. Moehn); Exh. 37, p. 16-17, l. 7-16 (Moehn Surrebuttal).
[203] *Id.* p. 17, l. 16-23 and Schedule MLM-2.

- From 2003 through 2005, EEInc. did not pay dividends to any of its shareholders. Instead, at that time EEInc. was paying down its debt.[204]

iii. The AmerenUE/EEInc. Power Supply Agreement.

- The Government and the Sponsoring Companies, through separate purchase power agreements, bought 100% of EEInc.'s power. The initial power contract was signed in 1953, and was amended and renewed from time to time over the past 50 years. The most recent version of the contract– the PSA – was signed in 1987.

- There was no renewal or "evergreen" provision in the PSA.[205]

- Only two provisions of the PSA addressed the term of that contract. The first, Section 6.01, provided: "This Agreement shall continue in force through December 31, 2005, unless cancelled pursuant to the provisions of Section 6.02."[206]

- Section 6.02 of the PSA gave each party to the contract the right to cancel its participation in the contract by giving a minimum of five years notice prior to the effective date of the cancellation.[207]

- The 40% of EEInc. stock owned by AmerenUE had no direct relationship with the money AmerenUE spent to buy EEInc.'s power. The PSA itself drew a distinction by specifying the "Annual Percentage" of the Joppa Plant's capacity that the Sponsoring Companies could purchase. From January 1, 1987 through December 31, 1989, the Sponsoring Companies could purchase, in the aggregate, 26.5 % of Joppa's capacity (of which AmerenUE had 10.6 %),[208] while from 1990 to the end of the PSA that percentage was lowered to 25 % (of which AmerenUE had 10 %).[209] The PSA also set out a procedure by which a Sponsoring Company could increase or decrease its Annual Percentage.[210]

- Reflecting this structure of the PSA, in the aggregate over the period 1954 – 2005, through prudent power purchases from EEInc., AmerenUE's customer's rates have included charges for power that covered at most approximately 16% of Joppa's costs.[211]

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[204] Tr. p. 2588, l. 16-24 (Mr. Naslund).
[205] Tr. p. 2452, l. 20-23 (Mr. Svanda); *id.* at p. 2673-74, l. 3-1 (Mr. Brosch); *id.* at p. 2714, l. 10-23 (Mr. Meyer); *id.* at p. 2736, l. 17-18 (Mr. Schallenberg).
[206] PSA, § 6.01 (Exh. 1 to Exh. 95 (Brosch Deposition)); Tr. p. 2550, l. 16-20 (Mr. Naslund).
[207] PSA, § 6.02 (Exh. 1 to Exh. 95 (Brosch Deposition)).
[208] PSA, § 2.05(a) (Exh. 1 to Exh. 95 (Brosch Deposition)).
[209] PSA, § 2.05(b) (Exh. 1 to Exh. 95 (Brosch Deposition)).
[210] PSA, § 2.05 (Exh. 1 to Exh. 95 (Brosch Deposition)).
[211] Exh. 37, p. 17, l. 1-2, 7-9 and Schedule MLM-3 (Moehn Surrebuttal). *Cf.* this to AmerenUE's 40% share of EEInc.'s stock. *See also* Tr. p. 2674, l. 6-17 (Mr. Brosch) (testifying that he has not done a calculation along these line).

- Under the PSA, EEInc. agreed to supply, and the Sponsoring Companies agreed to purchase, the amount of Joppa's capacity associated with each Sponsoring Company's Annual Percentage and the amount of energy from Joppa actually delivered to each Sponsoring Company.[212] No provision of the PSA required the Sponsoring Companies to pay EEInc. if EEInc. was unable to supply capacity or energy.[213]

- There was no transparent market for wholesale power in 1987, and so the pricing terms in the PSA, not surprisingly, used a cost-based formula common at that time. Indeed, only cost-based contracts or tariffs were allowed by the Federal Energy Regulatory Commission (FERC) at that time.[214]

- As was common for contracts for firm power like the PSA, both demand and energy charges were included in the calculation of the price in order to recover all the costs of producing that power. The demand charge included in the PSA was a typical demand charge, in that it compensated EEInc. for the fixed costs of producing power, including a proportionate return on and a return of the investment in the facility producing the power.[215] Accordingly, in the fixed costs covered by the PSA demand charges was a 15 % return on equity,[216] albeit that 15 % was applied to a limited and fixed amount of equity.

- The PSA also recognized that all the generating capacity of the Joppa Plant might not be scheduled by the Department of Energy (DOE) or the Sponsoring Companies. The PSA gave DOE a first right to schedule such unused capacity – what the PSA calls "Excess Joppa Energy' – after which a Sponsoring Company could schedule such energy. If more than one Sponsoring Company wished to schedule Excess Joppa Energy, that energy would be divided according to the proportion of each Company's ownership interest.[217]

- No provision of the PSA required the Sponsoring Companies to buy power not taken by DOE. No provision of the PSA required the Annual Percentage of the Sponsoring Companies to be increased if the DOE cancelled its participation in the PSA. As a practical matter, if the DOE did not, for whatever reason, take power from EEInc., and the Sponsoring

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[212] PSA, § 2.07 (Exh. 1 to Exh. 95 (Brosch Deposition)).
[213] Indeed, the PSA expressly limits the liability of the parties if a catastrophe struck the Joppa Plant. *See* PSA, § 7.03 (Exh. 1 to Exh. 95 (Brosch Deposition)) ("No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by act of God, insurrection or riot, act of the elements, failure of equipment, or for any other cause beyond its control.").
[214] Tr. p. 2348, l. 21-23 (Mr. Moehn).
[215] PSA, § 3.01 (Exh. 1 to Exh. 95 (Brosch Deposition)).
[216] Tr. p. 2347, l. 14-25 (Mr. Moehn); *id.* at p. 2710, l. 9-17 (Mr. Meyer); Exh. 5, p. 6, l. 21-23 (Svanda Rebuttal); Exh. 37, p. 6, l. 13-16, p. 18, l. 1-9 (Moehn Surrebuttal).
[217] PSA, § 2.08 (Exh. 1 to Exh. 95 (Brosch Deposition))

Companies did not exercise their option to schedule that power for their own use, EEInc. would have had the ability to sell that power to other potential buyers. If no other buyer purchased that power, the loss associated with the unsold power would fall on the owners of EEInc., that is, its shareholders. If such losses continued, EEInc. would have been driven into bankruptcy, and EEInc.'s shareholders would have lost their investment in the company. In that circumstance, AmerenUE's shareholders would have lost their investment in EEInc., but no loss could possibly have fallen on AmerenUE's ratepayers.

- Given that the purpose of the whole enterprise was to provide electricity to meet the large power demands of the Federal Government's Paducah facility, it is not surprising that the Federal Government in fact took the lion's share of EEInc.'s power. From 1954 - 2005, the Federal 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. Similarly, AmerenUE paid for only 16% of EEInc.'s total Joppa Plant charges while receiving approximately 15% of the total MWhs generated by the Joppa Plant over this same period.[218]

- Over the period from 1954 - 2005, the average annual cost of EEInc.'s power to AmerenUE was $14.19/MWh, including demand and energy costs.[219]

iv. The 1977 Air Pollution Control Bond.

- In 1977, the Commission granted AmerenUE's request to guaranty a pro-rata share of $10 million in bonds to be issued by EEInc. under its mortgage to pay for air pollution control equipment.[220]

- As part of providing security for these bonds, the Sponsoring Companies amended what was then their "Intercompany Agreement," to ensure that the bonds would be paid off if EEInc. was for some reason unable to produce power. The Sponsoring Companies committed themselves to providing sufficient funds, in proportion to their ownership interests in EEInc. to pay off the bonds if the Joppa Plant could not be operated.[221] AmerenUE was responsible for 7.6% of the outstanding indebtedness, which could increase to 9.5 % if one of the other Sponsoring Companies defaulted. Thus the maximum exposure of AmerenUE on the principal amount of the bonds was less than $5 million spread over 12 years, and its liability for interest payments averaged less than $250,000 per year. [222]

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[218] Exh. 36, p. 8, l. 4-9 and Schedule MLM-1 (Moehn Rebuttal).
[219] Exh. 36, p. 8, l. 14-16 (Moehn Rebuttal).
[220] Exh. 972 (Report and Order, Case No. EF-77-197 (June 24, 1977)).
[221] *Id.* at 3.
[222] *Id.* at 4.

- These bonds were due on December 15, 1989.[223] The Commission concluded that "the maximum exposure is small in comparison with [AmerenUE's] total assets and the possibility of any liability occurring is remote."[224] Each year, as a portion of the outstanding bonds were retired, the potential liability of AmerenUE decreased.[225] The bonds were retired by their due date.[226]

- In its 1977 Order approving the guaranty, the Commission concluded that giving AmerenUE the authority to undertake this guaranty was in the public interest,[227] but did not purport to make any judgments concerning any implications of this guaranty for rate-making purposes.[228]

v. The Inauguration of Market-Based Pricing for Wholesale Power and the Expiration of the PSA.

- Utilities have long entered into bilateral wholesale power transactions for the sale of various generation products, including firm power and non-firm or economy power. All wholesale power sales during the late 1970s and early 1980s were made at cost-based rates, though FERC did permit utilities some flexibility to sell capacity at below-cost rates to facilitate sales when there was excess capacity in a region.[229] However, selling capacity at a "discount" from its average or embedded cost is still selling at a cost-based rate, because the price is based on the seller's cost. Market-based rate authority, by contrast, allows a generator to sell power at a price above its cost. Absent such authority, a generator could not sell power for more than its cost.[230] In 1987, only cost-based pricing was available to EEInc. in selling its power.[231]

- Legislative and regulatory developments after the beginning of the PSA in 1987, 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), spurred the formation of competitive wholesale power markets.[232]

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[223] *Id.* at 2.
[224] *Id.* at 4.
[225] *Id.*
[226] Tr. 2347, l. 3-9 (Mr. Moehn).
[227] Exh. 972, at 4 (Report and Order, Case No. EF-77-197 (June 24, 1977)).
[228] *See id.* at 5.
[229] Exh. 37, p. 22, l. 6-10 (Moehn Surrebuttal). *See also* Wilbur C. Early, *Coordination Transactions among Electric Utilities*, PUBLIC UTILITIES FORTNIGHTLY, 31-37 (September 14, 1984).
[230] Exh. 37, p. 22, l. 11-13 (Moehn Surrebuttal).
[231] Tr. p. 1854, l. 19-22 (Mr. Rainwater); *id.* at p. 2351-52, l. 21-1 (Mr. Moehn).
[232] Exh. 37, p. 20, l. 17-22 (Moehn Surrebuttal).

- EEInc. applied for and received from FERC in December 2005 authority to sell power at market-based prices.[233]

- Nevertheless, EEInc. considered terminating the PSA before its 2005 expiration date because of the attractive possibility of selling its power at a market price, as opposed to the cost-based price used in the PSA. EEInc. did not do so because, in the judgment of the Board, that wholesale market had not matured sufficiently, with enough power generators having authority to sell at a market price, to make the risk of moving to market pricing acceptable, until about 2000 or later. Given that termination could take place only five years after notice was given, the PSA expired by its own terms before any termination could have taken effect.[234]

- Over a year before the PSA expired, Mr. Craig Nelson, then AmerenUE's Vice President of Corporate Planning, discussed the possibility of AmerenUE continuing to purchase power from EEInc. after the expiration of the PSA. Mr. R. Alan Kelley, Chairman of the EEInc. Board of Directors, advised Mr. Nelson that "he's not interested in selling at the lower of cost or market," as would be required by the affiliate transaction rules governing AmerenUE (but not EEInc.).[235]

- EEInc. assembled a team to advise its officers as to what actions EEInc. should take as the expiration of the PSA approached. The end result of that work was a draft of a new PSA based on market prices that the President of EEInc., Mr. Robert Powers, presented to the EEInc. Board.[236]

- The PSA expired by operation of its own terms on December 31, 2005.[237]

- AmerenUE neither took any action nor withheld any action that caused the expiration of the PSA. AmerenUE did not have any ability to extend the PSA.[238]

- Effective January 1, 2006, EEInc. entered into a new, ten-year PSA with Ameren Energy Marketing Company ("AEM"), a subsidiary of Ameren Energy Resources. Under the terms of the new PSA, all of EEInc.'s Joppa Plant capacity is under contract to AEM, and energy will be sold at market-based rates throughout the Midwest.[239]

- Because market prices fluctuate with market conditions, it is very possible that the cost-based prices used in the PSA could be higher than the market

[233] Exh. 37, p. 7, l. 1-2 (Moehn Surrebuttal).
[234] Tr. p. 1838-39, l. 24-8 (Mr. Rainwater).
[235] Exh. 404, p. 27-28, l. 13-4 (Kind Direct); Tr. p. 2791-92, l. 8-15 (Mr. Schallenberg).
[236] Tr. 2554-55, l. 3-1 (Mr. Naslund); *id.* at p. 2575, l. 15-25.
[237] Tr. p. 2550, l. 14-20 (Mr. Naslund); *id.* at p. 2582, l. 17-19.
[238] Tr. p. 2351, l. 16-17 (Mr. Moehn); *id.* at p. 2353, l. 3-17; *id.* at 2731, l. 9-11 (Mr. Schallenberg).
[239] *See* Tr., p. 2600, l. 3-5 (Mr. Naslund).

> price for EEInc.'s power in the coming years. For example, new environmental controls could greatly increase the costs of a coal-fired plant like the Joppa facility.[240] Similarly, it is difficult to quantify with any reasonable certainty over a period of several years into the future the difference between the cost-based price for EEInc.'s power used in the PSA and the market price for that power.[241]

b. Undisputed Principles of Law.

The following principles of law have not been disputed, either because the parties did not disagree or because only evidence establishing these principles was put into evidence by the testimony of Prof. Robert C. Downs, an expert whose credentials have not been questioned. No party other than AmerenUE offered the testimony of any witness competent to give evidence regarding the legal principles that must govern the Commission's resolution of the proposed EEInc. adjustment.[242]

i. Prudence.

- It is not imprudent for a utility not to take an act it has no legal power or right to take.[243]
- Signing a purchase power agreement that contains an expiration date is not imprudent.[244]
- If a regulated utility must procure additional generation to meet load, it has an obligation to obtain the lower cost generation available to meet this need, consistent with the provision of reliable service and other public service obligations.[245] Similarly, if the power from EEInc. became uneconomic, it

[240] Tr. p. 2296, l. 4-14 (Mr. Moehn).
[241] Tr. p. 2295-96, l. 18-3 (Mr. Moehn). *See also* Tr. p. 2578, l. 6-8 (Mr. Naslund) ("Q. [Mr. Mills] Okay. And does anyone know what the market prices will be for the next 15 years? A. No, they do not.").
[242] *See, e.g.,* Tr. p. 2691, l. 13-14 (Mr. Brosch) ("I can't help you with the legal fine points of what can be done or not done."); Exh. 103, p. 8, l. 17-19 (Schallenberg Deposition) ("I have never represented that I am an attorney or am qualified to provide legal opinions."); Exh. 501, p. 24, l. 21-22 (Brosch Direct) ("I am not an attorney and cannot offer any legal opinion regarding the obligations of management."); Exh. 95 p. 6, l. 5-10 (Brosch Deposition) ("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."); Exh. 214, p. 10, l. 4-5 (Staff witness Stephen G. Hill's Direct Testimony)(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).
[243] Tr. 2497-98, l. 11-1 (Mr. Svanda); Tr. p. 2675, l. 4-7 (Mr. Brosch); p. 2705, l. 19-22 (Mr. Meyer); p. 2786, l. 2-4 (Mr. Schallenberg).
[244] Tr. p. 2734, l. 10-13 (Mr. Schallenberg); *id.* at 2735, l. 20-23.
[245] Tr. p. 2627, l. 16-24 (Mr. Naslund); *id.* at p. 2677, l. 19-21 (Mr. Brosch); .

would be imprudent for AmerenUE not to buy more economic power from some other source.[246]

- "[T]he only justification for making [the proposed EEInc.] adjustment would be if you assumed that somehow AmerenUE should have or could have forced the Directors of EEInc. to approve the continuation of that [below-market-price] arrangement."[247]

ii. Duties of Corporate Directors and Officers.

- Like all boards of directors, EEInc.'s Board of Directors has the ultimate responsibility for managing the business affairs of EEInc.[248]

- While shareholders may express their opinion on any issue confronting a corporation in which they own stock, they are not entitled to tell the directors how to vote or otherwise how to manage that corporation. Directors must exercise their own independent judgment in whatever they are deciding.[249]

- 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 by-laws. 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 by-laws cannot override legal duties imposed by statute or the common law.[250]

- EEInc.'s Directors, like all corporate directors, have a duty of undivided loyalty to EEInc.[251]

- EEInc.'s Directors, like all corporate directors, have a fiduciary duty to EEInc. which obligates a director to act in the best interest of the corporation. Implicit in that obligation is a duty to maximize the profits of the corporation.[252] In practice, "maximizing profits" is a complicated endeavor.

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[246] Tr. p. 2715, l. 7-13 (Mr. Meyer); Exh. 99, p. 44, l. 13-24 (Meyer Deposition).
[247] Tr. p. 2412, l. 6-10 (AmerenUE witness Robert C. Downs).
[248] Tr. p. 2373, l. 16-18 (Prof. Downs); Exh. 46, p. 2, l. 13-15 (Downs Surrebuttal); *Hall v. Woods*, 156 N.E. 258 (Ill. 1927).
[249] Tr. p. 2381-82, l. 9-1 (Prof. Downs); Exh. 46, p. 2, l. 18-19 (Downs Surrebuttal); Tr. p. 2695, l. 2-5 (Mr. Brosch) (testifying that he does not know whether shareholders are entitled to manage a company in which they own stock); Exh. 103, p. 24, l. 4-7 (Schallenberg Deposition) (same); *Saigh v. Busch*, 396 S.W.2d 9 (Mo. App. 1965).
[250] Exh. 46, p. 2-3, l. 20-3 (Downs Surrebuttal); *id.* at p. 8, l. 22-23 ("Bylaw provisions that usurp the duties and obligations of the corporate directors are not enforceable."); Tr. p. 2695, l. 10-13 (Mr. Brosch); Exh. 103, p. 27, l. 12-14 (Schallenberg Deposition) (testifying that he does not know whether bylaws can change fiduciary duties).
[251] Tr. p. 2372, l. 6-10 (Prof. Downs); *id.* at p. 2383, l. 14-15; *id.*, at p. 2697, l. 6-10 (Mr. Brosch); Exh. 46, p. 3, l. 4-5 (Downs Surrebuttal); *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).
[252] Tr. p. 2372, l. 6-10 (Prof. Downs); *id.* at p. 2373, l. 18-19; *id.* at p. 2378, l. 2-4; *id.* at p. 2388, l. 2-8; *id.*, at p. 2697, l. 6-10 (Mr. Brosch); Exh. 46, p. 3, l. 6-8 (Downs Surrebuttal); *Forinash v. Daugherty*, 697 S.W.2d 294 (Mo.

As Prof. Downs noted, "[t]here are lots of interests that the directors will consider in deciding what to do, long-term, short-term, the amount of money, impact on employees, safety of the company, that ability of the company to – to handle possible future risks in the – the money coming into the company for a lot of reasons and uses."[253]

- As Mr. Naslund, an EEInc. director, summarized this obligation: "I think my duty as a director of EEI is to look after the fiscal health of that organization. That's my primary function in life. .. [T]hat comes in looking at … three specific things: One and firstmost is the benefit and health of the employees that work at the facility, that they receive fair wages and benefits; two, that the asset is looked after and is basically protected and kept as a healthy asset; and then finally, that the financials of the company are healthy and that we try to maximize the profitability of that facility."[254]

- There is no legal requirement that a board of directors, as a board, make an analysis before voting on an issue before it. The directors' duty requires that they reasonably inform themselves before they vote. They are entitled to engage their own knowledge about the market and about the future prospects of the corporation.[255]

- An individual serving on a board of directors can, and often does, "wear two hats." That is, a corporation will often seek as directors individuals experienced in business who are currently employed by, or on the boards of, other corporations. However, such an individual cannot legally wear both hats at the same time. That means that, while acting as a director of one corporation, that individual must act only in the best interests of that corporation, not any other entity in which he or the shareholders may have an interest.[256] "[T]he directors of the subsidiary owe the [fiduciary] duty to the corporation that they serve. And they're not entitled to see whether the parent is gaining or not gaining from that transaction."[257] Individuals serving as directors on the boards of two corporations "are required to exercise their judgment on behalf of each of the two parties."[258]

- The power produced by the Joppa Plant is a corporate asset of EEInc.[259]

- Selling its power at a fair market price is a corporate opportunity of EEInc., not of its shareholders.[260]

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).

[253] Tr. p. 2389, l. 6-16 (Prof. Downs).

[254] Tr. p. 2587, l. 5-15 (Mr. Naslund).

[255] Tr. p. 2402-03, l. 6-3 (Prof. Downs).

[256] Tr. 2373-74, l. 24-4 (Prof. Downs); *id.* at p. 2384, l. 6-17; Exh. 46, p. 3, l. 9-16 (Downs Surrebuttal).

[257] Tr. p. 2380-81, l. 24-2 (Prof. Downs).

[258] Tr. p. 2385, l. 13-15 (Prof. Downs).

[259] Exh. 46, p. 3, l. 17 (Downs Surrebuttal).

- EEInc.'s Board ultimately makes the decision at what price to sell EEInc.'s power.[261]

- Directors cannot legally defer to the wishes of control shareholders to transfer corporate assets to those shareholders at a below fair market price.[262] Shareholders are not entitled to take the assets of a corporation for less than the fair market value of those assets.[263]

- A director's use of corporate assets to further his own goals is a violation of his fiduciary duties. Similarly, a director may not take the corporation's assets to help another corporation in which he has an interest. 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.[264]

- The Board of Directors of EEInc. has the fiduciary duty to protect EEInc.'s assets and not permit the shareholders, or anyone else, to take its power without paying fair market value for it.[265]

- The EEInc. directors who were affiliated with AmerenUE and Kentucky Utilities were subject to conflicts of interest since those utilities were on the other side of sales of power by EEInc. As a result, the actions of those EEInc. directors would not be measured by the ordinary business judgment rule, but by a higher standard – whether any action taken was entirely fair to EEInc. The sale of that corporation's major income producing asset to anyone, including shareholders, for substantially less than its fair market value (a course apparently endorsed by the EEInc. directors affiliated with Kentucky Utilities), could not pass the entire fairness test. If the sale of EEInc.'s power to AmerenUE at substantially less than its fair market value had been approved by EEInc.'s directors, they would have violated their fiduciary duties to the corporation.[266]

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[260] Exh. 46, p. 3, l. 18-19 (Downs Surrebuttal); Tr. p. 2697, l. 1-5 (Mr. Brosch) (testifying that he does not know if the corporate opportunity to sell the Joppa plant power at fair market value does not belong to EEInc.'s shareholders).
[261] Tr. p. 2377, l. 11-13 (Prof. Downs); *id.* at p. 2694-95, l. 23-1 (Mr. Brosch); Exh. 46, p. 3, l. 20-21 (Downs Surrebuttal).
[262] Exh. 46, p. 4, l. 1-3 (Downs Surrebuttal); Tr. p. 2695, l. 14-18 (Mr. Brosch) (testifying that he does not know if directors are not entitled to defer to the wishes of control shareholders or transfer corporate assets to those shareholders at below fair market value); Exh. 103, p. 27, l. 15-19 (Schallenberg Deposition) (same).
[263] Exh. 46, p. 5, l. 22-23 (Downs Surrebuttal).
[264] Exh. 46, p. 4, l. 4-9 (Downs Surrebuttal); Tr. p. 2697, l. 12-16 (Mr. Brosch) ("suspects" that a fiduciary's use of corporate assets to further his own goals is a violation of his fiduciary duties, but does not know); *id.* at 2697, l. 17-20 ("suspects" that a director may not take the corporation's assets to help another corporation in which he has an interest, but does not know). .
[265] Exh. 46, p. 6, l. 4-6 (Downs Surrebuttal). *See, e.g., Weinberger v. UOP, Inc.*, 457 A.2d 701 (Del. 1983).
[266] Exh. 46, p. 16, l. 11-21 (Downs February Surrebuttal).

iii. The Impact of the PSA.

- AmerenUE's ratepayers do not own EEInc. or any asset of EEInc. [267] AmerenUE's shareholders paid for the EEInc. stock purchased by AmerenUE. Accordingly, if EEInc. sold its main asset, the Joppa Plant for a profit, only AmerenUE's shareholders would be entitled to share in that profit.[268]

- A contract pricing mechanism for the sale of any commodity, including that in the PSA between EEInc. and AmerenUE, does not give the buyer ownership rights of any kind concerning the assets of the seller or that commodity, nor does it create legal entitlements beyond the term of the contract.[269]

- The PSA's terms and conditions were relatively typical of long-term, firm power contracts of that era, 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.[270]

- Through AmerenUE's purchases of EEInc. power, AmerenUE's ratepayers paid for power and got power in return. The price of the power compensated EEInc. for all of the costs it incurred to produce that power, including its costs of capital. Such costs are normal components of the price for power (or for any commodity). Indeed, a seller would go bankrupt if the seller's price did not include all costs of producing his product. "[T]he 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."[271]

- The law has always held that "utility ratepayers pay for service and thus do not acquire any interest, legal or equitable, in the property of the company."[272] "Customers pay for service, not for the property used to render it."[273] "[P]urchases [from a utility] in no way convey[] an ownership interest in the facilities used to provide service."[274]

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[267] Tr. p. 1955, l. 22-24 (Mr. Rainwater); *id.* at p. 2349, l. 9-10 (Mr. Moehn); *id.* at p. 2672, l. 22-24 (Mr. Brosch); *id.* at p. 2710, l. 6-8 (Mr. Meyer); Exh. 103, p. 69, l. 20-22 (Schallenberg Deposition).

[268] *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).

[269] Exh. 46, p. 4, l. 10-14 (Downs Surrebuttal).

[270] Tr. p. 2347, l. 14-25 (Mr. Moehn); *id.* at p. 2710, l. 9-17 (Mr. Meyer); Exh. 5, p. 6, l. 21-23 (Svanda January Rebuttal); Exh. 103, p. 82, l. 21-24 (Schallenberg Deposition); *id.* at p. 84, l. 17-22.

[271] *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).

[272] *Illinois Pub. Telecommunications Assoc. v. FCC*, 117 F.3d 555, 569 (D.C. Cir. 1997)

[273] *Board of Pub. Util. Commissioners v. New York Telephone Co.*, 271 U.S. 23, 32 (1926).

[274] *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*,

c. The Proposed EEInc. Adjustment Cannot Be Justified.

The proposed EEInc. adjustment simply does not withstand examination in light of the facts and law in the record before the Commission. By any fair evaluation of that record, this adjustment cannot be justified and must be rejected.

d. The Expiration of the PSA Had No Unfair Impact on AmerenUE's Ratepayers.

Two, inter-related grounds are advanced by the other parties to support this adjustment. First, they claim it is warranted because the expiration of the PSA in some way had an inequitable impact on AmerenUE's ratepayers. Of course, the expiration of one contract, and the fact that, under Missouri's affiliate transaction rules, AmerenUE will no longer be able to buy EEInc.'s power, which it now wants to sell only at a market price, is not by itself unfair or in any way inequitable. To create some unfairness where there is none, the other parties make two further claims: that the PSA conveys a special status to AmerenUE's ratepayers (or gives this Commission broader jurisdiction over EEInc.) because the price for EEInc.'s power covered all the costs of producing that power, and that AmerenUE's ratepayers have a special status because they bore the risk of EEInc.'s operations in special ways beyond the terms of the PSA. Neither of these claims is true.

The PSA was a relatively standard, long-term firm power contract. Notwithstanding the characterizations of the other parties, the costs paid for in that contract were those related to producing the power received by AmerenUE's ratepayers. As the other parties' witnesses have admitted, such costs, including the ROE component, are commonly part of the price for power. Indeed, they must be, for otherwise the generator would have no way of paying for its costs and

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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).

would go out of business. In addition, the expense for these purchases of power from EEInc. were included in AmerenUE's cost of service and no suggestion has ever been made that these purchases were imprudent.

Though these particular purchased power expenses were "jurisdictional" in the sense that they were included in AmerenUE's cost of service, which is obviously subject to the jurisdiction of this Commission, that jurisdiction over those expenses does not, under any regulatory principle, give the Commission broader jurisdiction over EEInc.[275] Again, it is undisputed in the record that neither AmerenUE nor its ratepayers own EEInc., EEInc.'s Joppa Plant, or any other asset of EEInc. Nothing from EEInc. is in AmerenUE's rate base, and the record is clear that nothing about the PSA gave AmerenUE's ratepayers an ownership interest, or anything like an ownership interest, in EEInc. The fact that these expenses for purchased power are within AmerenUE's cost of service no more gives the Commission broader jurisdiction over the seller of that power (a distinct, out-of-state, corporation otherwise not within the Commission's jurisdiction), than does any purchase power contract, or, for that matter, any contract by which AmerenUE buys anything for use in serving its ratepayers.

Moreover, AmerenUE's ratepayers had nothing at all at risk in the operation of EEInc. AmerenUE's ratepayers put no money into EEInc. except for the money by which AmerenUE paid for, and its ratepayers received the benefit of, power generated by EEInc.'s Joppa Plant. It was AmerenUE's shareholders' money, which purchased EEInc.'s stock, that was at risk if EEInc. failed. As the testimony of the other parties makes clear, if the contract with EEInc. had

[275] This issue is fundamentally unlike the imputation of revenue from telephone directory publishing affiliates of regulated local exchange telephone companies. Originally such publishing operations were part of one phone company, but became part of an affiliate as part of the break-up of AT&T. In response to this unique circumstance, the Missouri General Assembly specifically granted the Commission the authority to impute revenues and costs associated with yellow pages directories published by an affiliate to the regulated local exchange telephone company. *See* MO. REV. STAT. §386.330.4; *Staff v. SWBT*, Case No. TC-93-224, 1993 Mo. PSC LEXIS 62, at *99-100 (1993). Thus, contrary to the claim made by one witness, *see* Exh. 501, p.29-30, l. 21-8 (Brosch Direct) the imputation of revenue from yellow pages affiliates is not authority for the proposed EEInc. adjustment.

become uneconomic, prudence would have dictated that AmerenUE terminate that contract as soon as possible and buy power from a more economic source. (Indeed, this illustrates the advantage of AmerenUE having only a contract with EEInc., as opposed to owning EEInc.'s Joppa Plant.) If other purchasers did not buy the power no longer being purchased by AmerenUE, EEInc.'s resulting losses would be borne only by its shareholders.

As the record also shows, contrary to the loose and unsupported statements of the other parties, the PSA did not require AmerenUE to make any guarantees, or be any kind of "back stop," concerning the purchase of power from EEInc. No provision of the PSA required the Sponsoring Companies to pay money to EEInc. if EEInc. was unable to supply capacity or energy. No provision of the PSA required the Sponsoring Companies to buy DOE's share of the Joppa Plant's power if DOE terminated its purchases (though the Sponsoring Companies had the option to do so).

Outside of the PSA, AmerenUE did guaranty a pro-rata share of the 1977 bond issued to buy air pollution control equipment. It is simply an assumption -- an utterly unsupported assumption at war with traditional regulatory principles -- advanced by the other parties to call this guaranty a risk borne by AmerenUE's ratepayers. Most obviously, the bond was paid off and no payment was ever required under this guaranty. Even at the time, this Commission considered any liability flowing from this guaranty to be "remote." Thus, whatever risk this guaranty posed, from today's vantage point it is highly theoretical and cannot now be the basis of this huge adjustment to AmerenUE's cost of service.

But even theoretically, the only AmerenUE investment in EEInc. was an investment of AmerenUE's shareholders, and as such, it is they who bore the risk of that investment and of that guaranty. AmerenUE witnesses have testified here that AmerenUE would not seek to recover in rates any losses that might have been incurred if payment had to have been made under this guaranty. No evidence contradicting this representation has been introduced. In addition, and more fundamentally, this Commission, under established regulatory principles, could not have allowed such losses to be passed on to ratepayers even if AmerenUE tried to do so. At bottom, the governing principles of law did not allow this guaranty to be a risk of AmerenUE's customers.

Even assuming that AmerenUE's ratepayers had some "risk" of some sort under this guaranty, the $8 million exposure of AmerenUE as a result of that guaranty[276] has no relationship at all to the $21.7 million to $75 million *per year* adjustment proposed by the other parties. Again, the "risks" of the 1977 bond guaranty cannot justify the proposed adjustment.

e. AmerenUE Had No Legal Right or Power to Compel EEInc. to Sell Power at a Below-Market Price.

The second, and necessary, ground advanced for this adjustment is that AmerenUE had some power to compel EEInc. to sell its power at a below-market price. This, also, is not true. First, and most obviously, the PSA expired by its own terms, and nothing in that contract gave any of the parties a right to extend or revive it.

Second, the fact that a majority of EEInc.'s Board of Directors were also affiliated with an Ameren company did not give AmerenUE any right to command those directors to sell EEInc.'s power at a below-market price. The most basic principles of corporate law require directors to exercise their judgment, and vote, solely to benefit the corporation on whose board they sit, regardless of any other interest they may have due to their other employment or affiliations. It is not at all surprising that these principles are set out in the record without dispute, as they reflect common sense and fairness. *Of course* we want directors to be loyal to their corporations and do the best they can for them. Directors are not supposed to feather their

[276] AmerenUE's share of that guaranty was $5 million of principal plus approximately $3 million in interest ($250,000 per year for 12 years).

own – or someone else's -- nests at the expense of their corporations. Not only investors, but the livelihood of a corporation's employees and those who otherwise participate in its operations, such as vendors and others in the local community, depend on such honest, independent service from directors.

While the judgment directors must exercise can often involve close calls, and reasonable people can differ over them, the record here shows that EEInc.'s decision to sell its power at a market price was not one of those close questions. This fact is confirmed by the other parties' own testimony. For example, the State's witness complained that EEInc.'s revenue jumped from $174 million to $370 million as a result of EEInc.'s decision to sell at a market price.[277] No evidence has been offered by the other parties to suggest how it would have been in the best interest of EEInc., its shareholders, its employees, and others dependent on its economic success, for EEInc. to forgo such additional, lawful revenues in order to sell power to AmerenUE solely to benefit AmerenUE's ratepayers. No law or principle of fairness supports the notion that EEInc. had a duty to subsidize AmerenUE's ratepayers in that way.

In sum, nothing about AmerenUE's relationship to EEInc. gave AmerenUE's ratepayers a special claim on the continuation of a below-market contract with EEInc., and AmerenUE had no right to compel EEInc. to act against its own, obvious best interests. This adjustment should be rejected.

f. The Proposed EEInc. Adjustment Would Violate the Constitution.

While the Commission should reject the proposed EEInc. adjustment on its own terms, as discussed above, this adjustment, should it be ordered by the Commission, would raise broader legal problems that also counsel rejection of the adjustment.

[277] Tr. p. 2686, l. 8-10 (Mr. Brosch).

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."[278] In enacting the FPA, "Congress has drawn a bright line between state and federal authority"[279] by "making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce."[280] States may not "regulate in areas where FERC has properly exercised its jurisdiction."[281] State regulation that entrenches upon FERC's jurisdiction is preempted by the FPA.[282]

The proposed EEInc. adjustment would, if adopted by the Commission, 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 arose from states' failure to honor "FERC-approved cost allocations between affiliated energy companies"[283] in setting (state-regulated) retail rates and other regulatory actions that frustrated FERC-approved rates,[284] the preemption here would arise from state regulatory action calculated to defeat the very implementation of a FERC order authorizing an out-of-state utility's market-based power sales.

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[278] 16 U.S.C. § 824(b). *See, e.g.*, *Nantahala Power Co. v. Thornburg*, 476 U.S. 953, 954 (1986); *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").
[279] *Mississippi Power & Light Co. v. Moore*, 487 U.S. 354, 374 (1988).
[280] *Nantahala Power*, 476 U.S. 954 (internal quotations and citations omitted).
[281] *Id.*
[282] *See, e.g.*, *id.*
[283] *Entergy*, 539 U.S. at 41.
[284] *See, e.g.*, *id.* at 42-45.

In 2005, FERC authorized EEInc. to sell power at market-based rates approved by FERC.[285] 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 Plant's power to AmerenUE under a cost-based contract (or on any other basis for that matter). That would unquestionably deny EEInc. the right and obligation to implement the FERC-approved tariff, and the tariff would become a nullity. But it would be no less objectionable—and no less an interference with FERC's order— for the Commission to recoup from an EEInc. shareholder (AmerenUE) the profits that EEInc. earns from the lawful 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. shareholder.[286] The regulatory encroachment on FERC's jurisdiction is equally objectionable in both cases.[287]

Not surprisingly, 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., OPC protested that 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

[285] *See* Order Granting Market-Based Rate Authorization in *Electric Energy, Inc.*, 113 FERC ¶ 61,245 (Dec. 8, 2005) (hereafter "FERC Order").
[286] 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 state law principles of corporate governance described above).
[287] *See, e.g.*, *Duke Energy Trading and Marketing, L.L.C. v. Davs*, 267 F.3d 1042 (9th Cir. 2001) (holding preempted state orders because, although they did not directly conflict with FERC order governing wholesale sale of energy, "in both purpose and [economic] effect [they] frustrated" FERC's orders).

shareholders of both AmerenUE and Ameren."[288] (The Commission did *not* join OPC in opposing EEInc.'s application seeking market-based rate authority.)

If OPC thought that the Commission could lawfully recover the ratepayers' alleged losses through the ratemaking imputation it now seeks, then it would have had no reason to protest EEInc.'s application to FERC. The OPC should not now be heard to argue that its proposed treatment of EEInc.'s energy sales would not conflict with FERC's order.[289]

ii. The Proposed Adjustment Would Confiscate The Unregulated Property Of AmerenUE's Shareholders And Therefore Constitute An Unlawful Taking In Violation Of The Fifth Amendment's Takings Clause.

The Fifth Amendment's Takings Clause (applicable to state regulatory action by incorporation under the Constitution's Fourteenth Amendment) prohibits the taking of a utility's property in state ratemaking procedures without "just compensation."[290] Normally state utility commissions need only be concerned with whether the proposed rates—in their "total effect"[291]— ensure a reasonable rate of return to the utility on the investment its makes to supply the regulated services.[292] Constitutional scrutiny under the Takings Clause cannot stop there, however, when the compensation factored into the proposed rate includes income produced from unregulated investments—that is, income from the sale of goods and services not regulated by, or under the jurisdiction of, the state regulator.

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[288] FERC Order at 9 (¶ 28).
[289] In rejecting its protest, FERC concluded that the matters raised by OPC are "better resolved at the state level." *Id.* But that conclusion in no way addresses whether the regulatory actions that 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 the preemption issue raised by AmerenUE in this proceeding. What is more, 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 regulatory 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).
[290] U.S. Const. amend. V. *See, e.g.*, *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989).
[291] *Duquesne Light*, 488 U.S. at 310.
[292] *See id.*

The operative rule here is simple and needs no extended discussion: Income from unregulated investments belongs to the utility's shareholders and to them alone. The Takings Clause does not allow a state to appropriate it through the ratemaking process— even, it should be emphasized, if the "total effect" of the rate set by the state is adequate to ensure a fair return on the utility's investment in providing the regulated service. An unconstitutional taking of property occurs whenever a utility is forced to "subsidize . . . regulated services with . . . revenues from unregulated services."[293]

This long-standing principle of takings jurisprudence condemns the proposed imputation here. The proposed imputation to AmerenUE income produced by the sale of energy unregulated by the Commission is income that belongs to the shareholders of AmerenUE. Its imputation to AmerenUE's revenue requirement in this proceeding would violate the Takings Clause just as surely as if the State of Missouri were to confiscate the income outside the context of a ratemaking proceeding.

iii. The Proposed EEInc. Adjustment Would Violate The Commerce Clause.

The Commerce Clause[294] contains both an affirmative grant to Congress to regulate interstate commerce and (by implication) a negative restriction on the states' ability "to

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[293] *Michigan Bell Tel. v. Engler*, 257 F.3d 587 (6th Cir. 2001). This unassailable principle of takings law traces its origins to the Supreme Court's decision in *Brooks Scanlon Co. v. Railroad Comm.*, 251 U.S. 396 (1920). *See Engler*, 257 F.3d at 594. *Cf. Panhandle E. Pipe Line Co v. FPC*, 324 U.S. 635, 641 (1945) (explaining that, to avoid "transgress[ing]" its jurisdiction, the Federal Power "Commission must make a separation of the regulated and unregulated business when it fixes the interstate wholesale rates of a company whose activities embrace both"). In *Engler*, the United States Court of Appeals for the Sixth Circuit held unconstitutional a state utility law merely because it failed "to adequately safeguard against confiscatory rates" arising from the compelled subsidization of regulated rates with the utility's "unregulated income streams." *Id.* at 594.

[294] U.S. CONST. art I, § 8.

discriminate or burden the interstate flow of articles of commerce."[295] The latter resides in what is known as the "dormant" (or "negative") Commerce Clause.[296]

State regulatory actions subject to commerce clause scrutiny fall into one of two categories that dictate the level of constitutional scrutiny: those that "regulate[] evenhandedly with only 'incidental' effects on interstate commerce" and those that "discriminate[] against interstate commerce" [297] The former type of regulatory action is valid "unless the burden imposed" on interstate commerce "is clearly excessive in relation to the putative local benefits." Regulatory action that discriminates against interstate commerce, on the other hand, is "virtually per se invalid."[298] Only if the state can establish, "under rigorous scrutiny," that its regulatory actions serve a legitimate state purpose that cannot be achieved by any alternative means will they survive constitutional scrutiny.[299] So exact is the scrutiny that rarely will a discriminatory state action survive challenge.[300]

No form of state action offends the Commerce Clause more than the regulation of economic activities outside the state's borders.[301] Such extraterritorial regulation is discriminatory no matter what its intended purpose.[302] If the "practical effect" of the regulation is to "control conduct beyond the boundaries of the State," it is discriminatory and therefore subject to strict judicial scrutiny under the above-referenced standard.[303]

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[295] *Oregon Waste Sys. v. Department of Environmental Quality*, 511 U.S. 94, 98 (1994).
[296] *See, e.g., American Trucking Ass'n, Inc. v. USF Holland, Inc.*, 545 U.S. 429, 433 (2005); *Dennis v. Higgins,* 498 U.S. 439, 447 (1991).
[297] *Oregon Waste*, 511 U.S. at 99 (citations omitted).
[298] *Id.* (internal citations and quotations omitted).
[299] *C & C Carbone, Inc. v. Town of Clarkstown,* 511 U.S. 383, 392 (1994).
[300] *See, e.g., id.*; *Oregon Waste*, 511 U.S. at 101.
[301] *See, e.g., Healy v. The Beer Institute*, 491 U.S. 324, 336 (1989). As a prominent commentator has explained, "the [U.S. Supreme] Court has articulated virtually a per se rule of invalidity for extraterritorial state regulation—i.e., laws which directly regulate out of-state-commerce, or laws whose operation is triggered by out-of-state events." Laurence H. Tribe, 1 AMERICAN CONSTITUTIONAL LAW 1074 (3d ed. 2000).
[302] *See, e.g., Healy*, 491 U.S. at 336; *see also, e.g., Oregon Waste*, 511 U.S. at 100 (emphasizing that the "purpose of, or justification, for a law has no bearing on whether it is facially discriminatory").
[303] *Healy*, 491 U.S. at 336.

The Supreme Court has recognized that while the "regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States," it is "particularly likely" to discriminate against interstate commerce.[304] In New *England Power Co. v. New Hampshire*,[305] for instance, the Court held facially discriminatory a New Hampshire regulatory commission order that required a regional utility company that operated in several states to "sell electricity to New Hampshire utilities in an amount equal to the output of its in-state hydroelectric facilities."[306]

The proposed regulatory action here is even far more repugnant to the Commerce Clause than the commission order held unconstitutional in *New England Power*. There, the state sought to regulate the allocation of power generated within its borders; here, the Staff and other parties seek to regulate the allocation of power generated entirely outside state borders. The proposed adjustment effectively claims for Missouri the right regulate to what entities (and at what prices) an unregulated out-of-state corporation, EEInc., may sell its product. None of the other parties can offer any lawful justification for this action, let alone one that could possibly satisfy the stringent mandates of the dormant Commerce Clause.[307]

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[304] *Arkansas Elec. Cooperative Corp. v. Arkansas Pub. Serv. Comm.*, 461 U.S. 375, 377 (1983); *accord Middle S. Energy, Inc. v. Arkansas Power & Light Co.*, 772 F.2d 404, 412 (8th Cir. 1985).
[305] 455 U.S. 331 (1982).
[306] *Id.* at 336. For other examples in the public utilities context, *see, e.g., id.*; *Camps NewFound/Owatonna, Inc. v. Town of* Harrison, 520 U.S. 564, 576-77 & n.9 (1997); *Middle S. Energy*, *supra*.
[307] It is of no consequence that the other parties seek to implement their regulatory objective indirectly by requiring AmerenUE to compensate Missouri ratepayers for the financial consequences of EEInc.'s decision not to sell AmerenUE cost-based power, rather than directly by ordering EEInc. to sell its power to AmerenUE. The Supreme Court's case law is replete with examples of unconstitutional state regulatory action that burdens interstate commerce in ways far more indirectly than the regulatory actions proposed here. *See, e.g., Camps NewFound/Owatonna*, 520 U.S. at 580; *see also, e.g., Alliance for Clean Coal v. Miller*, 44 F.3d 591, 595 (7th Cir. 1995) (holding that state discriminated against interstate commerce by, among other things, establishing financial incentives for utilities to use in-state natural resources for energy production).

iv. The Proposed EEInc. Adjustment Would Constitute Retroactive Ratemaking in Violation of AmerenUE's Due Process Rights.

The Commission may not, without violating AmerenUE's 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 when rates are set to recover from the utility "excess past profits" incorporated into earlier rates.[308]

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 "investment" by paying lower rates today and (presumably) for years to come.

Yet the expense of purchasing power from EEInc. (at very low cost) has been included in AmerenUE's cost of service for decades without any objection whatsoever. 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. But even if those expenses could now be considered in some way imprudent, the Commission cannot now, many years later, recoup the

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[308] *Utility Consumer Council of Missouri, Inc. v. Public Serv. Comm. of Missouri*, 585 S.W.2d 41, 54 (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.*, 976 S.W.2d 470, 479 (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.").

"overpayment" by adjusting current and future rates. To do that would clearly be to transgress the federal and state prohibition on retroactive ratemaking.

C. <u>Return on Equity</u>.

1. The Commission Should Allow an ROE at the High End of The Range of Recommended Roes Before It.

AmerenUE has requested an allowed ROE of 12%. The Company's two highly-qualified experts, Ms. Kathleen C. McShane and Dr. James H. Vander Weide, arrived at their recommended ROEs by estimating a base cost of equity for large groups of comparable risk companies, and then adjusting the base cost of equity estimate for the difference between the financial risk of the proxy companies and the financial risk of AmerenUE's recommended capital structure in this proceeding. Ms. McShane's base cost of equity estimate for her comparable companies is 11%, and her financial risk adjustment is 100 basis points; while Dr. Vander Weide base cost of equity estimate is 11.5%, and his recommended financial risk adjustment is 70 basis points. The experts of the other parties in this matter have recommended ROEs from 9.0% to 9.8%,[309] a range simply too low given the electric industry's need for infrastructure investments and investors' return expectations.[310]

[309] These recommendations are:

Witness	*Base Cost of Equity-Proxy Companies*	*Financial Risk Adjustment*	*Recommendation*
McShane (Company)	*11.0%*	*1.00%*	*12.00%*
Vander Weide (Company)	*11.5%*	*0.70%*	*12.20%*
Gorman (MIEC)	*9.8%*	*0.00%*	*9.80%*
King (OPC)	*9.65%*	*0.00%*	*9.65%*
Hill (Staff)	*9.375%*	*-0.125%*	*9.25%*
Woolridge (State)	*9.0%*	*0.00%*	*9.00%*

[310] AmerenUE expects to incur capital expenditures of about $3 billion over the next 5 years. *See* Tr., p.340, l.17-24 (Mr. Baxter).

2. AmerenUE's Allowed ROE Should Be No Less than the 10.9% to 11.25% Allowed ROEs the Commission Recently Granted The Empire District Electric Company (EDE) and Kansas City Power & Light Company (KCP&L).

In December 2006, the Commission granted EDE and KCP&L allowed ROEs equal to 10.9% and 11.25%, respectively.[311] Investors in AmerenUE face approximately the same risks as investors in EDE and KCP&L: all three utilities face the risk that they will earn less than their cost of capital as a result of rapidly rising and volatile fuel prices, rapidly rising health expenses and materials costs, and increasing capital expenditures. Standard & Poor's bond ratings are also similar for each company—BBB for AmerenUE and KCP&L and BBB- for EDE. Furthermore, interest rates are approximately the same now as when those cases were filed and when the orders in those proceedings were issued. The only thing that has changed since the time of the EDE and KCP&L cases is that the risk of investing in the electric utility industry as a whole has increased, with average electric utility betas increasing from .88 in December 2005, to .90 in May 2006, to 0.97 in January 2007. [312] Given the proximity in time of these three cases and the similarity in the companies' economic circumstances, capital markets would view a lower allowed ROE for AmerenUE as being unjustifiably punitive. Thus, AmerenUE's allowed ROE should be no less than the 10.9% to 11.25% allowed ROEs for EDE and KCP&L, and could reasonably be higher due to the increasing risk of investing in the electric utility industry.

3. The Commission's Recently Allowed ROEs in the EDE and KCP&L Cases Are in Line with Allowed ROEs in Other Jurisdictions.

Contrary to the State's representations, [313] this Commission's allowed ROEs in the EDE and KCP&L proceedings are not higher, but in fact are in line with allowed ROEs in other

[311] ER-2006-0315 and ER-2006-0314.
[312] Studies in both the EDE and KCP&L dockets are approximately for November 2005; the cases were filed in February 2006; at the time of the AmerenUE hearings data were available through February 2007. *See* Exh. 49, Schedule KMC-E3-1 (McShane July Direct), Exh.52, Schedule JVW-8-2 (Vander Weide July Direct); Exh. 53, Rebuttal Schedule JVW-2-4 (Vander Weide January Rebuttal).
[313] Tr., p. 2894-2903, l. 20-16 (Mr. Svanda).

jurisdictions. The average allowed ROE in 2006 for integrated electric utilities like AmerenUE was 10.7%, with individual company ROEs ranging from 10% to 11.9%.[314] For integrated Midwestern electric utilities, the average ROE was 11.0%, approximately the same as EDE's and KCP&L's allowed ROEs. [315] Also, as shown in the table below, most electric utilities in the Midwest outside Missouri operate under a fuel adjustment clause which reduces their risk.[316] The Commission's recently allowed ROEs in the EDE and KCP&L proceedings fall squarely in the middle of the range of allowed ROEs in other jurisdictions.

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[314] *See* Exh. 519, Regulatory Research Associates, "Major Rate Case Decisions January 2005 – December 2006," p. 5-7 (January 30, 2007) ("RRA Regulatory Focus"). See also Exh. 50, p. 20, l. 9-10 (McShane January Rebuttal).
[315] *Id.* at p. 5-7. In addition, the average FERC allowed ROE for electric utilities from April 2005 through October 2006 was 12.2%. Exh.. 53, p. 9, l. 15-16 (Vander Weide January Rebuttal). The Surface Transportation Board average allowed ROE for regulated railroads in 2006 was 15.18%. Exh. 53, p. 3, l.18-20 (Vander Weide January Rebuttal); *id.* at p. 95, l. 3-15; Exh. 54, p. 56, l. 13-20.(Vander Weide February Surrebuttal).
[316] *See also* Exh. 20, Schedule MJL-3-3 (Lyons January Rebuttal).

Electric Utility Allowed ROE And FAC Availability
Midwestern States, 2005 - 2006

Decision Date [1]	Case [2]	State [3]	Allowed ROE [4]	FAC Allowed in State [5]	Type of Utility [6]
1/28/2005	Aquila (KS)	KS	10.50	Yes	
3/10/2005	Empire District Electric (MO)	MO	11.00	No	
5/18/2005	Wisconsin Electric Power (WI)	WI	n/a	Yes	
7/19/2005	Wisconsin Power & Light (WI)	WI	11.50	Yes	
12/9/2005	Empire District Electric (KS)	KS	n/a	Yes	
12/12/2005	Madison Gas and Electric (WI)	WI	11.00	Yes	
12/13/2007	OGE Electric Service	OK	10.75	Yes	
12/21/2005	Cincinnati Gas & Electric (OH)	OH	10.29	n/a	Di
12/22/2005	Consumers Energy (MI)	MI	11.15	n/a	
12/22/2005	Wisconsin Public Service	WI	11.00	Yes	
12/28/2005	Dayton Power & Light (OH)	OH	n/a	n/a	
12/28/2005	Kansas Gas & Electric (KS)	KS	10.00	Yes	
12/28/2005	Westar Energy North (KS)	KS	10.00	Yes	
1/5/2006	Northern States Power (WI)	WI	11.00	Yes	
1/25/2006	Wisconsin Electric Power (WI)	WI	n/a	Yes	
2/23/2006	Aquila Networks-L&P (MO)	MO	n/a	No	
2/23/2006	Aquila Networks-MPS (MO)	MO	n/a	No	
3/3/2006	Interstate Power and Light (MN)	MN	10.39	Yes	
4/18/2006	MidAmerican Energy (IA)*	IA	11.90	Yes	
6/27/2006	Upper Penninsula Power (MI)	MI	10.75	n/a	
7/28/2006	Commonwealth Edison (IL)	IL	10.05	n/a	TD
8/31/2006	Detroir Edison (MI)	MI	n/a	n/a	
9/1/2006	Northern States Power (MN)	MN	10.54	Yes	
11/21/2006	Central Illinois Light (IL)	IL	10.12	n/a	TD
11/21/2006	Central Illinois Public Service (IL)	IL	10.08	n/a	TD
11/21/2006	Illinois Power (IL)	IL	10.08	n/a	TD
12/4/2006	Kansas City Power & Light (KS)	KS	n/a	Yes	
12/21/2006	Empire District Electric (MO)	MO	10.90	No	
12/21/2006	Kansas City Power & Light (MO)	MO	11.25	No	
12/28/2006	Black Hills Power (SD)	SD	n/a	Yes	
Averages, Midwest States					
	2005 integrated electric utilities		**10.8**		
	2006 integrated electric utilities		**11.0**		

Sources and Notes:
The Midwest is IA, IL, IN, KS, MI, MN, MO, ND, NE, OH, SD, and WI.
*ROE applies only to proposed 545 MW wind generation project.
[1] - [4]:Exh. 519, RRA Regulatory Focus.
[5]: Exh. 20, Schedule MJL-3-3 (Lyons January Rebuttal).
"n/a" indicates that the state did not appear on the schedule.
[6]: Exh. 519, RRA Regulatory Focus.
Di is distribution only and TD are transmission and distribution only entities.

4. The Company's ROE Recommendations Do Not Lie Outside the EDE and KCP&L "Zone of Reasonableness."

Staff's cross examination attempted to demonstrate that the Company's proposed ROE should be rejected because it fell outside a "zone of reasonableness" – a range 100 basis points above and 100 basis points below an average of allowed ROEs -- the Commission referred to in its EDE and KCP&L orders.[317] However, the Commission applied this zone by comparing a proposed base cost of equity (before adders or adjustments) to the zone:

> KCPL's recommended ROE of 11.5% is actually a recommendation of 11%, with a 50 basis point adder; thus, the Commission finds KCPL's recommendation of 11% plus any potential adder to make the ultimate ROE 11.37%, within the "zone of reasonableness."[318]

AmerenUE's ROE expert witnesses both arrived at their recommended ROEs by adding a financial risk adjustment to a base cost of equity. To be consistent with the Commission's approach, Ms. McShane's 11.0% base cost of equity[319] and Dr. Vander Weide's 11.5%,[320] not the estimates as adjusted, should be compared to a zone of reasonableness. AmerenUE's base cost of equity estimates obviously fall within the Staff's 9.5% to 11.5% "zone of reasonableness,"[321] and are, by the Staff's logic, presumptively reasonable.

5. A Zone of Reasonableness in this Case Should Reflect the Allowed ROEs of Integrated Electric Utilities, Not Wires-Only Electric Utilities.

A "zone of reasonableness" as a reference point to evaluate whether some cost of equity estimates are obviously either too high or too low can be a useful tool as long as it reflects the allowed ROEs of comparable entities. For example, a zone should not include the typically lower allowed ROEs for "wires-only" utilities that no longer have regulated electric generation facilities.

Allowed ROEs for integrated Midwestern electric utilities (like AmerenUE) averaged 10.7% in 2005 and 2006, while the average allowed ROE for wires-only electric utilities were 10.0% (2005) and 9.9% (2006). [322] Construction of a fair zone of reasonableness for this

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[317] Tr. p. 2847-50, l. 24-22 (Ms. McShane) and Tr. p. 2866-68, l. 2-2 (Dr. Vander Weide).
[318] Order ER 2006-0314 at 22.
[319] *See*, Exh. 49, p. 4, l. 3 (McShane July Direct).
[320] *See*, Exh. 52, p. 6, l. 2 (Vander Weide July Direct).
[321] Tr., p. 2815, l. 16-17 (Mr. Thompson).
[322] Exh. 50, p. 20, l. 9-10 (McShane January Rebuttal).

proceeding, then, should begin with a center of 10.7%. But that center needs to be raised (to at least 11.0%) because of additional data: (1) the Commission recently authorized returns of 10.9% and 11.25% for two integrated electric utilities in Missouri; (2) the average allowed ROE for Midwestern integrated electric utilities in 2006 was 11.0%; and (3) the recent average FERC allowed ROE for electric transmission facilities was 12.2%.[323]

The few utilities in the Northeast that have been allowed single-digit ROEs differ significantly from AmerenUE in that they are mostly wires-only utilities located in a few restructured states in the Northeast.[324] Useful comparison to these utilities is further diminished by the fact that the allowed rate of return of one is set to increase, of another was arrived at as a settlement, and of the third is being challenged on appeal as being confiscatory.[325] The average allowed ROE of 11% for integrated electric utilities in the Midwest remains a better midpoint estimate.

6. Allowed ROEs for Integrated Electric Utilities Are Not Declining.

In response to questions from Commissioner Appling, Mr. Hill erroneously claimed that allowed ROEs for electric utilities are declining, and that the 11.9% MidAmerican Energy allowed ROE is irrelevant to this proceeding.[326] The average allowed ROE for integrated electric utilities comparable to AmerenUE did not decline from 2005 to 2006. Rather, the average allowed ROE for Midwestern integrated electric utilities increased from 10.8% in 2005 to 11.0% in 2006.[327]

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[323] Exh. 53, p. 9, l. 15-16 (Vander Weide January Rebuttal).
[324] Exh. 6, p. 10, l. 24-26 (Svanda February Surrebuttal); Exh. 519, RRA Regulatory Focus, p. 6, 10 n.6.
[325] Exh. 519, RRA Regulatory Focus, p. 10 n.6 (Central Hudson Gas and Electric); *Petition for Base Rate Increase, Order On Settlement Agreement: Unitil Energy Systems, Inc.*, DE 05-178, Order No. 24,677. (New Hampshire Utilities Commission October 6, 2006) (Unitil Energy Systems); *Petition for Rehearing and Request for Oral Argument of New York State Electric & Gas Corporation*, Case 05-E-1222, at 16, 19 (New York State Public Service Commission filed September 7, 2006).
[326] Tr., p. 3022-23, l. 10-12 (Mr. Hill).
[327] *See* Exh. 20, Schedule MJL-3-3 (Lyons January Rebuttal); Exh. 53, p. 3, l.18-20 (Vander Weide January Rebuttal); *id.* at p. 95, l. 3-15; Exh. 54, p. 56, l. 13-20.(Vander Weide February Surrebuttal).

The 11.9% MidAmerican Energy allowed ROE was awarded for a planned major investment in a wind energy project[328] under an Iowa law providing for a determination of regulatory treatment before funds are invested in a project. This allows a utility to decline to commit to a project if the regulatory treatment will not result in a return commensurate with other investments of comparable risk. The 11.9% ROE for the MidAmerican project was the result of a settlement between the utility and the other parties in the proceeding approved by the Iowa regulators.[329] Clearly this return of 11.9% was understood by these adverse parties as sufficient to justify the utility's investment in the project while maintaining fair and reasonable rates. Thus, this 11.90% allowed ROE is especially relevant because it achieved the same goals the Commission has here: providing an incentive for AmerenUE to continue to invest in its Missouri operations while assuring fair and reasonable rates for AmerenUE's customers.

7. Allowed ROEs Are Not Lagging Behind an Alleged Decline in Cost of Capital.

Mr. Hill also wrongly claimed that allowed ROEs were lagging behind a decline in the cost of capital.[330] If anything, the opposite is true because interest rates in fact are expected to rise, as Mr. Hill's own testimony establishes. In his direct testimony, Mr. Hill referenced Value Line's outlook for long-term government bond yields, which anticipated a .50% increase relative to the level prevailing at the time Mr. Hill prepared his testimony.[331] The Value Line expectation cited by Mr. Hill that long-term government bond yields would reach 5.5% by 2008 is in line with the consensus estimate of interest rates cited by Dr. Vander Weide[332] -- that 20-

[328] Tr., p. 2897-98, l. 14-9 (Dr. Vander Weide).
[329] *In re MidAmerican Energy Co., Order Approving Stipulation and Agreement*, Docket No. RPU-05-4 (State of Iowa Dept. of Commerce Utilities Bd. 2006).
[330] Tr.p. 3012, l. 5-14 (Mr. Hill).
[331] Exh. 214, p. 19, l. 32-33 (Hill December Direct).
[332] Exh. 52, p. 37, n. 11 (Vander Weide July Direct).

year Treasury yields are expected to increase to 5.4%. Ms. McShane also referenced the expected interest rate increase.[333]

Moreover, the business risk of electric utilities' regulated operations is increasing, stemming largely from an increasingly uncertain cost environment, including uncertainty about the costs themselves and the ability to recover them in rates. This uncertainty is made more acute by the need to make significant capital expenditures. For example, Moody's has singled out the decline in utilities' free cash flow as a result of rising operating and investment expenditures as an "alarming" trend.[334] The entire electric utility industry has experienced deterioration in credit quality, increasing credit risks.[335] Regulatory and political risks have increased.[336]

These rising risks are reflected in increasing betas, which are a key measure of investment risk as perceived by investors. Ms. McShane's history of betas for her sample of comparable electric utilities indicates that the betas of electric utilities have risen from approximately 0.65 at the end of 2002 to 0.90 in mid-July 2006.[337] At a market risk premium of approximately 7.0%, this increase in betas results in a cost of equity increase for an electric utility of 1.75 percentage points. Betas have continued to increase since that testimony was filed. Dr. Vander Weide's comparable utilities' July 2006 beta of 0.90[338] rose to 0.97 by January 31, 2007,[339] an increase close to .50%.

In sum, allowed ROEs are in fact lagging behind an increase in the cost of capital.

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[333] Exh. 49, p. 29-30, l. 13-11 (McShane July Direct).
[334] Exh. 54, p. 7, l. 17-18 (Svanda February Surrebuttal).
[335] Exh. 54, p. 8, l. 14-22 (Svanda February Surrebuttal)..
[336] Exh. 54, p. 9, l. 14-22 (Svanda February Surrebuttal).
[337] Exh. 49, Schedules KCM-E3-1, KCM-E3-2 (McShane July Direct).
[338] Exh. 52, Schedule JVW-8-2 (Vander Weide July Direct).
[339] Exh. 53, Rebuttal Schedule JVW-2-4 (Vander Weide January Rebuttal).

8. Any Reasonable Estimate of the Cost of Capital Must Take Into Account Differences in Financial Risk.

The cost of capital for a company is undeniably a function of the company's total risk, including its business and financial risk. 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."[340] Shareholders' risk increases with the firm's leverage, and investors rely on market values in evaluating that risk.[341] While Mr. Hill agrees that financial economists measure financial risk using market value, he argues that there also is support for the use of book values. [342] The literature relied upon by Mr. Hill simply does not support this claim.[343]

While the other parties' witnesses object to any recognition of the differences in financial risk in estimating ROE,[344] their arguments 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. If the utility is allowed to earn (and happens to earn) the ROE that investors expect, then the investors' market return will equal the cost of equity and the market-to-book value remains unchanged.[345] Here, the proxy companies used to estimate the cost of equity have lower financial risk than is associated with the book-value capital structure of AmerenUE relied upon in this proceeding.

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[340] Exh. 54, p 5, l.3-8 (Vander Weide February Surrebuttal). *See also* Exh. 51, p. 4, l. 2-13 (McShane February Surrebuttal).
[341] Exh. 51, p. 8, l. 20-23 (McShane February Surrebuttal); Exh. 54, p. 13, l.16-17 (Vander Weide Surrebuttal).
[342] Exh. 215, p. 13, l. 12-13 (Hill January Rebuttal).
[343] Exh. 51, p. 9-10, l. 1-25 (McShane February Surrebuttal); Exh. 54, p. 13-15, l. 11-14 (Vander Weide February Surrebuttal).
[344] Exh. 705, p. 23-29, l. 14-17 (Gorman December Direct); Exh. 551, p. 3-5, l. 3-20 (Laconte December Direct); Exh. 215, p. 2-24, l. 12-13 (Hill January Rebuttal); Ex. 409, p 18-19, l. 26-27 (King January Rebuttal); Exh. 508, p. 36-37, l. 6-22 (Woolridge January Rebuttal).
[345] Exh. 50, p. 14-16, l.11-5 (McShane January Rebuttal).

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.[346]

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.[347]

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 percentages to calculate the overall cost of capital to be applied to AmerenUE's original cost rate base.[348]

Another criticism of recognizing the differences in financial risk is the claim that it leads to circularity in the regulatory process.[349] This circularity argument is completely based on the mistaken belief that Ms. McShane and Dr. Vander Weide rely on AmerenUE's market value capital structure.[350]

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[346] Exh. 54, p. 11-12, l. 20-5 (Vander Weide February Surrebutal).
[347] Exh. 49, p. 41, l. 2-8 (McShane July Direct); Exh. 54, p. 17, l. 6-22 (Vander Weide February Surrebuttal).
[348] Exh. 51, p. 6-7, l. 16-7 (McShane February Surrebuttal), Exh. 54, p. 10-11, l. 17-5 (Vander Weide February Surrebuttal), Exh. 215, p. 2, l. 15-20 (Hill January Rebuttal).
[349] Exh. 215, p. 6, l. 3-13 (Hill January Rebuttal); Exh. 403, p. 9, l. 21-27 (King December Direct).
[350] Exh. 50, p. 16-17, l. 6-2 (McShane January Rebuttal); Exh. 54, p. 10, l. 1-16 (Vander Weide February Surrebuttal).

Dr. Woolridge also 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.[351] 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.[352] Also, Mr. Hill argues that stock prices incorporate book value capital structure although clearly stock prices incorporate market as well as book value information.[353]

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%.

9. Allowed Roe Should Not Be Tied To Utility Performance.

During the hearing, there was understandably much discussion of AmerenUE's performance over the last year. Any evaluation of that performance – whether good or bad – provides no reliable benchmark by which to determine allowed ROE. For example, while someone who believes AmerenUE's performance has not been good might argue that the Company should not be "rewarded" with a certain ROE, Ms. LaConte indicated that AmerenUE's ROE should be lower because it "is a well run company."[354] Clearly, judgments of a utility's performance can be drummed into service on behalf of any level of ROE. Such judgments simply do not fairly help the Commission determine an appropriate ROE.

The Commission's deliberations should not depart from the well-established, traditional understandings of the task in setting an allowed ROE: the utility must be given the opportunity to

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[351] Exh. 508, p. 36, l. 17-21 (Woolridge January Rebuttal).
[352] Exh. 53, p. 61-64, l. 19-21 (Vander Weide January Rebuttal).
[353] Exh. 215, p. 14, l. 10-23 (Hill January Rebuttal); Exh. 51, p. 11, l. 1-9 (McShane February Surrebuttal); Exh. 54, p. 16-17, l. 1-3 (Vander Weide February Surrebuttal).
[354] Tr., p. 2945, l. 4-6 (Ms.LaConte) (emphasis added).

earn a return on investment commensurate with that of comparable risk enterprises;[355]maintain its financial integrity;[356] and attract capital on reasonable terms.[357] Paradoxically, a reduction to the allowed ROE due to an assessment that AmerenUE's service has not been as reliable as it should be would simply frustrate efforts to make that service as reliable as AmerenUE, its customers, and this Commission expect.

Penalizing AmerenUE through a reduction in the allowed ROE would be sending the wrong signal to investors at a time when utilities will be required to make significant infrastructure investments in generation, transmission and distribution. The International Energy Agency, World Energy Investment Outlook 2003 has "estimated that more than $1.6 trillion will need to be invested in the North American power sector over the next 30 years, and that the world-wide requirement for electric utility investment will approach $10 trillion.[358] AmerenUE will need to compete for capital both domestically and globally. To do so, it must be allowed the opportunity to earn a return that will continue to allow it to attract capital on reasonable terms and conditions and that will be compatible with the standard of comparability with returns of other enterprises with corresponding risks."[359] As pointed out by Mr. Svanda, "This is not an environment in which it is easy to attract new investors."[360] A punitive ROE would signal to the investment community that they should direct their future capital investments elsewhere.

This is not to say that AmerenUE could not improve its response to major weather events. Nor is this is to say that an objective system of rewards and penalties tied to specified standards

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[355] *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 40 (March 10, 2005) ("*Empire District*") at 40 (quoting *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1943)).
[356] *Empire District,* at 39 (quoting *Bluefield Water Works & Improv. Co. v. Public Serv. Comm'n of West Virginia,* 262 U.S. 679, 690 (1923)).
[357] *Empire District,* at 40 (quoting *Hope Natural Gas Co.,* 320 U.S. at 603).
[358] Exh. 50, p. 8, l. 2-5 (McShane January Rebuttal).
[359] *See* Exh. 50, p. 8, l. 5-9 (McShane January Rebuttal).
[360] Exh. 6, p. 12, l. 9-10 (Svanda February Surrebuttal).

of service and reliability would be unreasonable. However, an arbitrary reduction in the allowed return to punish AmerenUE for outages due to uncontrollable weather events would not only be unfair; it would be irresponsible. As Mr. Svanda stated, "Setting rates below appropriate levels will tend to undermine, not foster, continued investment in distribution systems and continued improvement in the operations and maintenance activities needed to minimize storm damage and improve storm response."[361]

AmerenUE has some of the lowest electric rates around,[362] operates a reliable electric system that in recent periods has been slightly above average in terms of reliability, and has, given the circumstances, done a good job during recent outages.[363] 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[364] and the generally more challenging environment facing AmerenUE.[365]

10. 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 Ms. LaConte who does not estimate ROE, select 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 this ROE testimony 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 book value of equity without acknowledging the difference in financial risk. (2) The Company witnesses rely on

[361] Exh. 6, p. 14-15, l. 21-2 (Svanda February Surrebuttal).
[362] Exh. 3, Schedule WLB-15 (Warner February Surrebuttal).
[363] Exh. 6, p. 14-15, l. 6-2 (Svanda February Surrebuttal), Exh. , p. 6-7, l. 22-4 (Zdellar February Surrebuttal).
[364] Exh. 6, p. 7, l. 16-18 (Svanda February Surrebuttal).
[365] Exh. 1, p. 7-9, l. 18-14 (Baxter July Direct).

several standard estimation methods and weight the methods equally, while some of the other parties' witnesses favor one methodology, the DCF method. (3) AmerenUE's witnesses 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 technical literature suggests is the superior approach, while some other witnesses rely on historical and/or subjectively chosen growth rates.

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

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.[366] The Commission has recognized this principle in the past.[367] In contrast, Mr. King, Mr. Hill, and Dr. Wooldridge claim that the DCF model is more "reliable" and weight this model more heavily with Mr. King and Dr. Woolridge giving weight only to the their DCF estimate.[368] 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 it produces.[369]

b. 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,

[366] Exh. 49, p. 15-16, l. 8-12 (McShane July Direct).
[367] Exh. 50, p. 17-18, l. 18-4 (McShane January Rebuttal) citing the *Empire District* at 45.
[368] Exh. 214, p. 35-36, l. 12-7 (Hill December Direct) Exh. 403, p. 19, l. 21-25 and p. 23, l. 20-27 (King December Direct), Ex. 507, p. 19, l. 10-15 (Woolridge December Direct**)**.
[369] Exh. 49, p. 24-25, l. 20-4 (McShane July Direct) Exh. 52, p. 25-26, l. 21-9 (Vander Weide July Direct).

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.[370]

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.[371]

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 select 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.[372] Mr. Hill claims that regulators are "not aware of the significant new research regarding the market risk premium and the reduction of long-term investor return expectations."[373] 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 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.[374] Similarly, Dr. Woolridge's relative 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%

[370] Exh. 52, p. 37, l. 5-13 (Vander Weide July Direct).
[371] Exh. 49, p. 30-36, l. 3-12 (McShane July Direct), Exh. 52, p. 29-37, l. 16-3 (Vander Weide July Direct).
[372] Exh. 50, p. 32-39, l. 2-11 (McShane January Rebuttal); Exh. 52, Schedule JVW 9-1 (Vander Weide July Direct).
[373] Exh. 214, p. 15, l. 9-12 (Hill December Direct).
[374] Exh. 50, p. 39-40, l. 10-2 (McShane January Rebuttal).

higher.[375] Finally, Mr. King estimates his market risk premium using a DCF methodology.[376] As noted by Dr. Vander Weide, Mr. King's implementation of the model has several flaws that bias the cost of equity estimate downwards.[377] Had Mr. King instead relied on standard Ibbotson Associate data for the market risk premium, his results would substantially higher.[378]

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 that what has historically been achieved.[379]

c. 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 been presented and the witnesses differ in their choice of input, 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.[380] Mr. Hill and Dr. Woolridge note forecasted as well as historical growth rates on a number of parameters and then subjectively choose a number.[381] The subjectivity in Mr. Hill and Dr. Woolridge's choice of a growth rate impacts the estimated cost of equity significantly. For example, Ms. McShane

[375] Exh. 50, p. 51, l. 15-18 (McShane January Rebuttal).
[376] Exh. 403, p. 21-22, l. 19-5 (King December Direct).
[377] Exh. 53, p. 98-99, l. 13-22 (Vander Weide January Rebuttal).
[378] Exh. 50, p. 72, l. 1-6 (McShane January Rebuttal), Exh. 53, p. 100, l. 1-11 (Vander Weide January Rebuttal).
[379] Exh. 50, p. 24-24, l. 7-30 (McShane January Rebuttal), Exh. 43, p. 43-44, l. 1-5 (Vander Weide January Rebuttal).
[380] Exh. 52, p. 20-21, l. 9-21 (Vander Weide July Direct), Exh. 50, p. 42, l. 1-4 (McShane January Rebuttal) Exh. 53, p. 38-40, l. 24-8 (Vander Weide January Rebuttal).
[381] Exh. 214, Schedule 4-7 (Hill December Direct); Exh. 507, Schedule JRW-7 (Woolridge December Direct), Exh. 53, p. 30, l. 1-5 (Vander Weide January Rebuttal).

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.[382] Similarly, Dr. Woolridge picks growth rates that are lower than the projected growth rates and thereby downward biases the cost of equity estimates.[383] 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.[384]

For all the above reasons, AmerenUE believes that the record now before the Commission should lead the Commission to chose an allowed ROE near the higher end of the range of estimates that have been put before it.

D. Capital Structure.

1. The Capital Structure Recommended by The Company Should Be Adopted.

The Company has recommended a capital structure, along with the cost of long-term debt, short-term debt, preferred stock, and common equity, as follows:[385]

	Amount (millions)	Percent of Total	Cost	Weighted Cost
Long-Term Debt	$2,552	44.964%	5.473%	2.461%
Short-Term Debt	$45	0.795%	5.360%	0.043%
Preferred Stock	$115	2.017%	5.189%	0.105%
Common Equity	$2,964	52.224%	12.000%	6.267%
Total	$5,675	100%		8.876%

All parties to this proceeding accepted AmerenUE's recommended cost of long-term debt, cost of short-term debt, and cost of preferred stock and most parties accepted AmerenUE's

[382] Exh. 50, p. 42, l. 1-5 (McShane January Rebuttal).
[383] Exh. 53, p. 53, l. 1-12 (Vander Weide January Rebuttal).
[384] Exh. 50, p. 67, l. 20-22 (McShane January Rebuttal).
[385] Exh. 56, Schedule LRN-E5-1 (Nickloy September Supplemental Direct).

proposed capital structure. Specifically, Mr. Gorman[386] for MIEC and Dr. Woolridge[387] for the State explicitly relied on the capital structure and cost of debt and preferred stock filed by the Company while other witnesses did not comment on these aspects of the case. Mr. King for OPC and Mr. Hill for Staff accepted AmerenUE's cost of debt and preferred stock but took some issue with the Company's recommended capital structure.

As is common in Missouri, the Company's suggested short-term debt is netted against the average CWIP (Construction Work in Progress) balance.[388] Mr. Hill argues that this increases the cost to rate payers over a capital structure that relies on a 5-quarter average short-term debt figure.[389] This point is irrelevant because the Company, as acknowledged by Mr. Hill, followed standard practice in Missouri in determining the amount of short-term debt to include.[390] In addition, (i) no other party took issue with the Company's short-term debt, (ii) a standard test year consists of12 months and not five quarters, and (iii) Mr. Hill appears to be discussing a capital structure that differs from that recommended by the Company.[391] Therefore, Mr. Hill's comments on short-term debt should be ignored.

Mr. Hill also disagrees with the removal of the effects of AmerenUE's investment in its wholly owned subsidiary, UEDC, from its balance of common equity.[392] No other party has taken issue with this treatment, and as explained by Mr. Nickloy, the purpose of the adjustment is to remove any impact of the investment in UEDC from AmerenUE's balance sheet for rate making purposes.[393] As this proceeding is setting rates for AmerenUE, it is AmerenUE's capital

[386] Tr. p. 2928, l. 14-20 (Mr. Gorman).
[387] Exh. 507, p. 2, l. 1-5 (Woolridge December Direct). See also Exh. 500, Schedule D (State Joint Accounting Schedules).
[388] Exh. 56, p. 3, l. 3-9 (Nickloy September Supplemental Direct).
[389] Exh. 214, p. 22, l. 3-21 (Hill December Direct).
[390] Exh. 214, p. 21, l. 12-19 (Hill December Direct).
[391] See Ex. 214, Schedule 2, p. 2 (Hill December Direct) and Exh. 56, Schedule LRN-E5-1 (Nickloy September Supplemental Direct).
[392] Exh. 214, p. 22-23, l. 22-19 (Hill December Direct).
[393] Exh. 57, p. 2-3, l. 7-5 (Nickloy January Rebuttal).

structure on a stand-alone basis that is relevant, and hence Mr. Hill's inclusion of equity in UEDC is improper.

Testifying on behalf of Office of Public Counsel, Mr. King argued that a "small proportion – 5.2 percent – of AmerenUE's 'equity' takes the form of long-term debt at the parent company level. And an even smaller portion – 0.5 percent – takes the form of parent company short-term debt. The effect is to overstate the equity portion of AmerenUE's capital as it ultimately reaches Ameren Corporation's shareholders."[394]

Mr. King also contends that it is common to adjust for "double leverage" effects in regulatory proceedings regarding telephone companies and increases the debt component of AmerenUE's capital structure based on this argument.[395] Regardless of what it is "common" to do from Mr. King's perspective, here no such adjustment is called for simply because there is no double leverage present in AmerenUE's recommended capital structure.[396]

Moreover, such double-leverage adjustments have been rejected in numerous telecommunications cases, and Staff witness Hill's recommendation of a double-leverage adjustment was recently rejected by the Washington Utilities and Transportation Commission.[397]

During Commissioners Clayton's and Gaw's cross-examination of Mr. Nickloy, the issue of credit rating agencies reactions to regulatory issues and their independence was discussed at length.[398] State regulatory developments are one of several important financial considerations and risk factors that are closely monitored by credit rating agencies. Commission orders, even Staff recommendations in rate cases, can have an immediate positive or negative impact on the credit quality and credit ratings of the regulated utilities. This direct relationship between a

[394] Exh. 403, p. 4-5, l. 28-4 (King December Direct).
[395] Exh 403, Schedule CWK-1 (King December Direct).
[396] Exh. 57, p. 3, l. 9-10 (Nickloy January Rebuttal).
[397] Exh. 53, p. 101, l. 9-21 (Vander Weide January Rebuttal).
[398] Tr. p. 2950-93, l. 21-13 (Mr. Nickloy)

regulatory actions and rating agency reaction to it, however, does not mean that the rating agencies are "calling the shots" about what the Commission can or cannot do.[399] The fact that regulatory actions, just like management actions, will affect a utility's credit quality does not mean that rating agencies try to influence (or even have an interest in influencing) such regulatory or management actions. Rather, rating agencies are simply reporting on the facts and circumstances that influence companies' credit quality and assign ratings consistent with that credit quality.

AmerenUE competes for capital in a national, if not international, financial market. Investors pay close attention to a company's financial metrics and risks, which are monitored by credit rating agencies. While not every change in financial metrics, business risks, management actions, or regulatory developments will result in an immediate change in a Company's credit rating, a change in any one or a combination of these factors will affect credit quality. As credit quality trends slowly over time or changes abruptly because of certain developments, specific rating actions (i.e., an upgrade or downgrade of a rating or a rating outlook) may occur. But just like changes in costs or other market fundamentals can lead to an improvement or deterioration of credit quality that can trigger a rating action, so can management and regulatory actions. Neither the Commission nor AmerenUE management can avoid the fact that actions which negatively affect the credit quality of the Company will immediately be taken into consideration by investors, which in turn affects the access to and costs of capital. Credit rating agencies are simply one of the means by which investors obtain such information.

As Mr. Nickloy noted in his testimony, for example, Moody's February 2003 and July 2006 rating actions were due to deteriorating business factors, such as lower revenue growth,

[399] For example, Commissioner Appling has raised the question whether we have to a point where rating agencies direct Missouri regulatory policy Tr. p. 2951, l. 8-10 ("Have we come to a point that we're letting the rating agencies direct traffic for these major – major companies?")

higher operating expenses, and large capital expenditures among others, not any specific regulatory or management actions.[400] However, as he also pointed out, Moody's most recent downgrade was caused not only by higher costs and lower associated financial metrics of AmerenUE, but also the higher regulatory risk resulting from Staff's financially adverse recommendation in this rate case.[401]

The record reflects that that "only a couple years ago, for example, rating agencies and financial analysts described the Missouri regulatory environment as 'challenging,' 'poor,' and 'marked by relatively low allowed ROEs, low depreciation allowances, and the lack of a permanent fuel adjustment clause.'"[402] However, it is also clear that the rating agencies similarly recognize Commission actions that have improved the State's regulatory environment and made it more consistent with the mainstream of regulatory policy on a national basis.[403] These improvements include regulatory orders that made Missouri depreciation policy more consistent with those of other states and that set utilities' allowed returns on equity at levels more consistent with those of other utilities across the country. Credit rating agencies have pointed to both the "potentially improving regulatory situation in Missouri" as well as the "new fuel, purchased power, and environmental cost recovery mechanism passed in Missouri" as a positive factor for the outlook of Missouri utilities' credit ratings and financial health.[404] But not surprisingly, the potential for adverse regulatory outcomes and delays in the implementation in fuel adjustment clauses still negatively affect utility credit ratings. This is not only reflected in the March 2007 downgrade of AmerenUE by Moody's as discussed by Mr. Nickloy, but also in

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[400] Tr. p. 2962, l. 11-63 (Mr. Nickloy).
[401] Tr. p. 2964, l. 15-24 (Mr. Nickloy)
[402] Exh. 4, p. 6, l. 10-13 (Svanda July Direct) citing Standard & Poor's, Empire District Rating Placed on CreditWatch Negative, RatingsDirect, September 28, 2004; Standard & Poor's, Standard & Poor's Research Summary: Empire District Electric Co, Jan 20, 2004; A.G. Edwards, Equity Research: Electric Utilities, July 3, 2002; Ratings on Empire District Electric Co. Lowered to 'BBB', RatingsDirect, July 2, 2002.)
[403] Exh. 4, p. 5-6, l. 17-5 (Svanda July Direct)
[404] *See* Exh. 105 (Moody's, Credit Opinion: Union Electric, December 16, 2005). *See* also Exh. 6, p. 5-6, l. 10-7 (Svanda July Direct) citing Exh. 105 (Moody's Credit Opinion, Dec. 16, 2005).

the Standard and Poor's recent downgrade of The Empire District Electric Company, which noted that "restrictive" Missouri regulations regarding fuel and purchased-power costs still causes "less-than-adequate recovery of O&M expenses and other costs."[405]

As Mr. Nickloy further testified, rating agencies have a strong interest in maintaining the quality and objectivity of their reports. While higher credit ratings will be in the interest of investors, the specific level of ratings is of little interest to the rating agencies. Rather, the interest of credit rating agencies is to produce high-quality credit reports and assign ratings based on facts and circumstances.[406] Doing so independently and without bias is the cornerstone of a high-quality rating process.[407] While rating agencies will gather information through Company-provided financial information and interviews with individuals such as Mr. Nickloy,[408] the agencies do not allow AmerenUE to influence their conclusions or their options.[409] Any concerns over the lack of the agencies' independence would jeopardize their reputation, franchise, and business of providing objective ratings to the investors who follow their reports and pay for their services.[410]

E. Emission Allowances.

1. Background.

Sulfur dioxide (SO2) emissions allowances are certificates issued by the U.S. Environmental Protection Agency, beginning in the mid-1990's, which permit the bearer to emit one ton of sulfur dioxide. SO2 emissions allowances can be bought, sold, or traded, and there is

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[405] Exh. 4, p. 6, l. 14-17 (Svanda July Direct) (citing Standard & Poor's, Research Update: Empire District Electric Downgraded To 'BBB-' On Expected Tight Financials, May 17, 2006).
[406] Tr. p. 2986, l. 9-25 (Mr. Nickloy).
[407] Tr. p. 2983-84, l. 7-4 (Mr. Nickloy). Companies such as AmerenUE also pay the agencies to obtain a rating of its debt, but that is a prudent course of action because obtaining official credit ratings increases investors' demand and decreases the cost of the securities. Tr. p. 2977-79, l. 10-22 (Mr. Nickloy).
[408] Tr. p 2957, l. 13-14 and Tr. 3002, l. 11-22 (Mr. Nickloy)
[409] Tr. p. 2989-91, l. 16-24 (Mr. Nickloy).
[410] Tr. p. 2983-84, l. 7-4 (Mr. Nickloy).

an active market for allowances in which AmerenUE has participated over the last 10 years.[411] The idea behind the SO2 emissions allowance program is to use the free market to most efficiently achieve timely overall reductions in SO2 emissions in the U.S. Companies that can most efficiently reduce SO2 emissions to meet mandated targets will do so and will sell or trade their excess allowances, and companies that have less efficient means at their disposal to reduce emissions can acquire those allowances and thereby defer the need to reduce SO2 emissions. In addition, SO2 emissions allowances can be "banked" for use in future years if they are not needed for compliance in the year they are issued.[412]

AmerenUE has participated in the SO2 emissions allowance market almost since its inception. Pursuant to authorization granted by the Commission it has sold some of its allowances and swapped some current vintage allowances for allowances with future vintages. Using the latter technique, from 2000 to 2005 AmerenUE increased its bank of allowances by 225,144 allowances, having a market value on the date surrebuttal testimony was filed in this case (February 27, 2007) of approximately $93 million.[413] AmerenUE's successful participation in the allowance market has provided it with a relatively large bank of allowances. Its access to these allowances will permit it to proceed deliberately in installing pollution control equipment. AmerenUE will be in a position to learn from the experience of other utilities that must install pollution control equipment at an earlier date, and it will be able to take advantage of any technological advances in pollution control equipment that may develop, all to the ultimate benefit of its customers.[414]

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[411] Exh. 63, p. 1, l. 18-24 (AmerenUE witness James C. Moore's Surrebuttal Testimony).
[412] Tr. p. 3455, l. 15 to p. 3456, l. 5 (Mr. Baxter).
[413] Exh. 63, p. 9, l. 9-13 (Moore Surrebuttal).
[414] Exh. 63, p. 9, l. 14-18 (Moore Surrebuttal).

2. Establishing a "Normal" Level of SO2 Allowance Margins is Inappropriate and Unwise.

The issue in this case is how much, if any, of the margins from SO2 emissions allowance sales should be included in the calculation of AmerenUE's revenue requirement. One difficulty in addressing this issue is that AmerenUE's sales of allowances vary considerably from period to period. The main consideration governing AmerenUE's decision to sell allowances is that allowances can only be sold if they are in excess of those the Company anticipates that it will need to use for environmental compliance purposes, based on its overall environmental compliance strategy, potential changes in environmental laws, the cost of compliance measures and other considerations. If the Company determines that there are excess allowances available, a variety of market considerations must be weighed to determine if and when allowances will be sold.[415] These considerations have led to significant deviations in allowance sales levels over time. For example, in the test year for this case, AmerenUE sold only approximately $3.9 million of SO2 allowances.[416] However, in the six-month update period, the Company sold over $30 million of allowances, in part to offset storm-related operations and maintenance (O&M) costs.[417] Given variations of this magnitude, it is virtually impossible to calculate a "normal" level of SO2 allowance sales that can be expected to occur in future periods. Moreover, including a "normal" level of SO2 allowance margins in the Company's revenue requirement would provide an inappropriate incentive for the Company to attempt to meet this target level of sales, regardless of other important considerations such as its need to use SO2 allowances for environmental compliance, and market conditions that may make selling SO2 allowances unattractive during a particular period.

[415] Tr. p. 3418, l. 20 to p. 3419, l. 4 (Mr. Baxter).
[416] Exh. 207, p. 25, l. 3-4 (Staff witness John P. Cassidy's Direct Testimony).
[417] Exh. 2, p. 12, l. 1-4 (Baxter Rebuttal).

3. The Company's and Staff's Proposed Treatment of SO2 Allowance Margins Should be Adopted.

The Company and the Staff have approached this issue in basically the same way. In short, both the Company and the Staff propose to use SO2 allowance margins from the test year and update period to offset O&M costs from the extraordinary July 2006 and November/December 2006 storms, and flow-through to customers all SO2 allowance sales margins and SO2 premiums paid to coal producers beginning January 1, 2007.[418] If no FAC is approved in this case, a regulatory liability account should be established to track these items and the balance in the account should be flowed through as a fuel expense or credit in the Company's next rate case. If an FAC is approved, these items should be flowed through the FAC as they occur.[419] The Company believes that this approach is meritorious because (a) it protects customers from having to pay the substantial O&M costs associated with the extraordinary 2006 storms through their rates; (b) it relieves the Commission from having to undertake the extremely difficult task of arriving at a "normalized" level of SO2 margins to include in the Company's revenue requirement; (c) it ensures that every dime of SO2 allowance margins the Company receives after January 1, 2007, will be credited to customers—there will be no under- or over-collection of SO2 allowance margins resulting in undeserved profits or losses for the Company; (d) it avoids the creation of inappropriate incentives for the Company to meet an arbitrary target level of SO2 allowance margins included in its revenue requirement, and thereby ensures that the Company's focus will be in optimizing the value of its allowance bank for its customers, whether by selling/trading allowances or saving them for compliance purposes; (e) it prevents other

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[418] Under the Staff's proposal the Company could recover approximately $13.6 million in excess 2006 storm O&M costs, which would be amortized over five years. Exh. 226, p. 3, l. 16-18 (Meyer Surrebuttal). The Company is willing to support that proposal. However, in the alternative, the Company is willing to agree to forego recovery of any excess 2006 storm costs if the other portions of the Staff's and Company's joint recommendation are approved. Tr. p. 3441, l. 22 to p. 3442, l. 6 (Mr. Baxter).

[419] Exh. 209, p. 13, l. 1-3 (Cassidy Surrebuttal); Mr. Baxter thoroughly explained this position in response to cross-examination by OPC. Tr. p. 3441, l. 18 to p. 3442, l. 24.

market participants from taking advantage of the knowledge that AmerenUE has a target level of allowance sales it is striving to reach each year;[420] and (f) it treats AmerenUE's SO2 allowance margins in a manner generally consistent with the treatment provided SO2 allowance margins of Kansas City Power & Light Company and The Empire District Electric Company.[421]

The OPC and the State of Missouri do not agree with the Staff and Company proposal. Instead, they argue that a significant "normal" level of SO2 allowance margins should be imputed in AmerenUE's revenue requirement based on margins AmerenUE has received over the last four to five years. Specifically, OPC witness Ryan Kind argues for an imputation of $23,993,951 in annual allowance margins,[422] and State of Missouri witness Michael Brosch argues for an imputation of $20,653,000.[423] Mr. Brosch also advocates the establishment of an adjustment mechanism that would track deviations from the level of margins imputed in the Company's revenue requirement. Nonetheless, the approach of both OPC and the State is totally unsupported. Neither Mr. Kind nor Mr. Brosch have provided any evidence that an average of historical levels of margins is an appropriate amount of margins to impute in the future. They have provided no analysis at all of how many allowances AmerenUE will need to use for environmental compliance purposes in future years, and no analysis of how many additional allowances (if any) AmerenUE is permitted to sell under its limited authority granted by the Commission. On the witness stand, Mr. Brosch admitted that he did no such analysis of these factors, which are critical in determining the threshold question of whether AmerenUE has *any* excess allowances it can sell in the future.[424] As a consequence, the OPC and the State have

[420] Exh. 63, p. 2, l. 18-23 (Moore Surrebuttal).
[421] Tr. p. 3541, l. 12-23. (Mr. Cassidy).
[422] Exh. 408, p. 17, l. 3-4 (Kind Surrebuttal).
[423] Tr. p. 3557, l. 17-18 (Mr. Brosch).
[424] Tr. p. 3558, l. 1 to p. 3559, l. 11 (Mr. Brosch).

simply failed to adequately support their proposed treatment of allowance margins and this treatment should therefore be rejected.

OPC witness Kind raised some questions with regard to one particular SO2 allowance transaction involving Dynegy options.[425] However, AmerenUE witnesses Moehn, Borkowski, and Moore have thoroughly explained this transaction.[426] Based on these witnesses' explanation, this transaction was completely appropriate, and it certainly provides no basis for rejecting the Staff's and Company's proposed treatment of SO2 margins in favor of OPC's imputation of almost $24 million in annual margins.

Finally, during cross-examination the State of Missouri hypothesized that AmerenUE could potentially "monkey with" the SO2 premium in a coal contract in order to get a lower base coal cost, and raised the specter that initiation of the regulatory liability account on January 1, 2007 might constitute retroactive ratemaking.[427] However, Staff witness Cassidy testified that the Commission would have the authority to disallow any costs that could result from any hypothetical "monkeying."[428] Mr. Cassidy also testified that the proposal does not constitute retroactive ratemaking.[429] Clearly this proposal does not constitute retroactive ratemaking, any more than the numerous other instances in which the Commission has ordered the establishment of a regulatory asset or liability account to hold cost or revenue items for future ratemaking treatment. Indeed, retroactive ratemaking only occurs if a *customer rate* that has been established and paid is retroactively changed. *State ex rel. Midwest Gas Users' Ass'n v. PSC*, 976 S.W.2d 470, 479 (Mo.App. 1998). AmerenUE's customer rates prior to January 1, 2007, will not change due to implementation of the regulatory liability account approach.

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[425] Exh. 406, p. 10, l. 11 to p. 16, l. 3 (Kind Rebuttal).
[426] Exh. 37, p. 30, l. 13 to p. 36, l. 15 (Moehn Surrebuttal Testimony); Exh. 65, p. 1, l. 18 (AmerenUE witness Maureen Borkowski Surrebuttal Testimony); Exh. 63, p. 4, l. 21 to p. 10, l. 8 (Moore, Surrebuttal).
[427] Tr. p. 3536, l. 11 to p. 3537, l. 21 (Mr. Cassidy).
[428] Tr. p. 3539, l. 2-10 (Mr. Cassidy).
[429] Tr. p. 3538, l. 16-18 (Mr. Cassidy).

At bottom, the OPC's and State's arguments against the proposed treatment of SO2 margins are meritless. For all of the reasons stated herein, the Commission should approve the Staff and Company proposal.

F. <u>Combustion Turbine Generators</u>.

1. Pinckneyville and Kinmundy.

The full cost of these combustion turbine generators (CTGs) should be reflected in rate base. Extensive and persuasive evidence exists in this case, as well in prior cases of this Commission and in an extensive proceeding before the FERC that the at-cost (net book value) price paid for them was a prudently incurred price that was at or below market. No contrary evidence that withstands scrutiny is before the Commission.

a. Background on the Pinckneyville and Kinmundy (P & K) CTG Purchase.

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."[430] The P & K CTGs were acquired at net book value from AmerenUE's affiliate, Ameren Energy Generating Company (AEG), as contemplated by the S & A. The acquisition, which AmerenUE had intended to close in 2003, had been delayed for two years because of attempts by NRG,

[430] Exh. 116, Stipulation and Agreement, Case No. EC-2002-1, p. 6, referred to herein as S & A.

which at the time owned CTGs located in Audrain County, Missouri, to prevent necessary FERC approval of the sale[431] and force AmerenUE to purchase the Audrain plant.[432]

The heart of this issue is whether this was a prudent transaction on the part of AmerenUE. As the FERC decision indicates, this Commission participated in the FERC docket referenced above, and stated therein that it "prefers the certainty and reliability of dedicated assets and that AmerenUE's [FERC] application to purchase the generating units is consistent with this preference and the [Case No. EC-2002-1] Stipulation."[433] This Commission also indicated to the FERC that it will "review the prudence of the transaction,"[434] which it is now doing in this case.

Importantly, it is the State and OPC[435] that bear the burden of establishing that the transaction was not prudent because 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.[436] Indeed, 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 with respect to the transaction at issue.[437]

There was no abuse of discretion here. It is undisputed that AmerenUE paid a price that equaled AEG's cost – i.e., paid the net book value on AEG's books for these CTGs.[438] It is also undisputed that the FERC, after eight days of evidentiary hearings, found that the price paid by

[431] FERC Order 473, 108 FERC ¶ 61,081, Docket No. EC03-53-000 (July 29, 2004). This case arose because Section 203 required approval for the transfer because these CTGs were FERC jurisdictional assets. Exh.60, p. 34, l. 23 to p. 35, l. 1 (Voytas Rebuttal).
[432] Exh. 60, p. 34, l. 24 (Voytas Rebuttal); Tr. p. 3128, l. 16-25 (Mr. Voytas).
[433] FERC Order 473, ¶27.
[434] *Id.*
[435] It is apparent that the Staff, which initially proposed a prudence disallowance, but then withdrew its support for any disallowance at all, did not believe its own review of the transaction established any imprudence.
[436] *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).
[437] *See, e.g., State ex rel. GTE v. Pub. Serv. Comm'n*, 537 S.W.2d 655 (Mo. App., W.D. 1976).
[438] As discussed later, this cost was at or below market and consequently the Company has also met the pricing standards in the Commission's affiliate transaction rules.

AmerenUE was in the public interest,[439] that "AmerenUE appropriately decided among alternatives on the basis of price and non-price factors [and] . . . AmerenUE's acquisition of the Pinckneyville and Kinmundy facilities will not represent an exercise of a safety net for Ameren and its subsidiaries."[440] It is undisputed, as discussed in detail below, that just three months before the transaction closed, this Commission found that a higher price for CTGs was an appropriate price to use for evaluating AmerenUE generating resource (indeed, for CTGs) acquisition decisions.

b. The P & K Acquisitions Were Prudent.

The Company agrees that this Commission has the authority to review the prudence of the P & K acquisitions, and that the FERC's findings in this regard are not "binding" on the Commission as a matter of law. But the fact that the FERC, after eight days of evidentiary hearings devoted to determining if the acquisitions were in the public interest found that they were, and rejected what are essentially the same arguments being made by the State and OPC in support of their proposed rate base adjustments, is powerful evidence that AmerenUE did not (as the State and OPC, at their core, essentially allege) favor its affiliate, AEG, and pay a price that was too high because it was their affiliate that was selling these CTGs.

The FERC decision is just a part of the record that supports the prudence of this transaction. Indeed, given the abandonment by Staff of any support for a rate base disallowance, the Commission is left with the extensive testimony of Company witness Rick Voytas (Exhibit 60), and Mr. Kind's brief and cursory testimony on three pages of his direct testimony and part of one page of his surrebuttal testimony[441], and about six pages of Mr. Brosch's brief direct

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[439] FERC Order 473, ¶ 25.
[440] *Id.* at ¶ 46. A "safety net" would have existed if AmerenUE had paid AEG more than the fair market value of these CTGs.
[441] Tr. p. 3223, l. 6-13 (Mr. Kind.

testimony.[442] An examination of that testimony demonstrates that the State and OPC have failed to meet their burden to establish the imprudence of AmerenUE's decision to purchase these CTGs at net book value.

c. The Proposed Adjustments are Flatly Inconsistent with this Commission's Findings in the Metro East Case.

Mr. Kind admitted that this Commission in the Metro East case (Case No. EO-2004-0108) rejected his argument that AmerenUE erred by pricing CTGs at $471 per kW in that case, and under cross-examination he read into the record in this case the Commission's order in the Metro East case which rejected his argument.[443] He admitted that his proposals in this case were respectively just 41 and 66 percent of the $471 per kW price this Commission found to be appropriate in the Metro East case.[444] The Commission will note that the Metro East order was entered in February of 2005,[445] and the P & K purchase was closed just three months later, in May of 2005,[446] at a blended price ($439.50/kw), which is more than $30 per kilowatt *below* the price found appropriate by this Commission in the Metro East case for a mix of CTGs needed by AmerenUE.[447]

Mr. Kind does his best to downplay the Commission's Metro East decision on this point because he knows the importance of the Commission's finding in that case. In that case, the Commission had to decide what price would be appropriate if AmerenUE were to go out and buy or build CTGs instead of freeing-up (in effect, instead of acquiring a slice of) more baseload capacity by transferring away its Metro East service territory. The Commission specifically found (again a mere three months before the P & K transaction closed) that AmerenUE would

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[442] Tr. p. 3247, l. 4-11 (Mr. Brosch).
[443] Tr. p. 3231, l. 13-19 (Mr. Kind).
[444] Tr. p. 3238, l. 1-8. A simple calculation from page 35, l. 25-26 and Attachment 7 of Mr. Kind's Direct testimony (Exh. 404) reveals that his "primary" recommendation is that the Commission allow in rate base only about 42 per cent of the actual cost of P & K, a write-down of some $145 million.
[445] Report and Order on Rehearing, Case NO. EO-2004-0108, p. 24, (Feb. 10, 2005).
[446] Tr. p. 3074, l. 15-18 (Mr. Voytas).
[447] Exh. 60, p. 4, l. 14 (Voytas Rebuttal).

have to pay approximately $471/kw for CTGs if it were to use CTGs to meet its capacity needs in lieu of transferring away its Metro East service territory.[448] In that case Mr. Kind, as he does now, argued that $471/kw was too high. It defies logic to now argue, as Mr. Kind does, that this Commission in February 2005 can find that $471/kw was an appropriate price upon which to judge whether AmerenUE should buy or build CTGs to meet its resource needs, but that $439.50/kw, paid just three months later, is an inappropriate price for AmerenUE to have paid to buy CTGs to meet its resource needs.

d. The Audrain Facility Owned by NRG, and Relied Upon by Mr. Kind, Provides No Basis for a Rate Base Adjustment in this Case.

Mr. Kind admitted that both of his alternative recommendations for adjustments were based either in part or wholly on comparisons with the Audrain facility which was a focus of the FERC proceedings.[449] His "main" recommendation was based on the 2006 acquisitions by AmerenUE of dissimilar[450] CTGs from bankrupt or severely financially distressed sellers (NRG and Aquila),[451] one of which was the very same Audrain facility, and his other "secondary" recommendation was based entirely on a 2002 non-binding "indicative proposal" regarding the Audrain plant.[452] Even though it is clear that none of these represent true market-value sales, no

[448] "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." Tr. p. 3231, l. 13-19 (Report and Order on Rehearing, Case NO. EO-2004-0108, p. 24, (Feb. 10, 2005) (Mr. Kind)).

[449] Tr. p. 3240, l. 18 to p. 3241, l. 1 (Mr. Kind).

[450] Exh. 60, p. 6, l. 12 to p. 10, l. 8; p. 40, l. 8-11 (Voytas Rebuttal); see Tr. p. 3110, l. 24 to p. 3111, l. 12 (Mr. Voytas).

[451] Tr. p. 3170, l. 4-5 (Mr. Voytas); Exh. 404, p. 35, l. 14-27 and Attachment 7 (Kind Direct).

[452] Tr. p. 3240, l. 9 to p. 3241, l. 1.

other sales formed a part of his alternative recommendations.[453] For that reason alone, OPC cannot carry its burden.

Mr. Kind also admitted that he made no comparison of the characteristics of P & K with the characteristics of the other three CTGs acquired at fire sale prices in 2006 except the sales prices of each.[454] He admitted that the owner of the Audrain plant which figured as the sole basis for his secondary recommendation and as one of three in his primary recommendation had never operated it commercially prior to its sale in 2006 after filing for bankruptcy.[455] Finally, he agreed that AmerenUE's refusal to purchase the Audrain facility in 2002 (as he and others had urged) produced savings on this one purchase alone when it was eventually obtained in 2006 of $136 million -- $136 million of lower rate base that directly benefits ratepayers in this rate case.[456]

At bottom, what Mr. Kind is trying to do is "have his cake and eat it too." AmerenUE, wisely, did not buy the Audrain CTGs prior to 2006, at a time when severe transmission constraints limited their efficacy, and when NRG was seeking a higher price, as discussed below. Rather, AmerenUE was patient, and bought these CTGs when the transmission problems were largely resolved and when they could be bought at an even lower price. Indeed, one could argue that the fair market value of CTGs when AmerenUE bought the Audrain CTGs was higher than the price AmerenUE paid. Should AmerenUE be given a rate base "*write-up*" to reflect the fact that it acquired those assets at below-market prices? AmerenUE is not suggesting that it should

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[453] *Id.*

[454] Tr. p. 3241, l. 10-15 (Mr. Kind); Exh. 98, p. 63, l. 19 to p. 64, l. 2 (Kind Deposition). *See also* Exh. 60, p. 9, l. 7 to p. 10, l. 8 (Voytas Rebuttal). Mr. Voytas described these 2006 purchases as one-time opportunities to acquire regulated generating capacity at far below market prices, at savings in the hundreds of millions of dollars. As Mr. Voytas also testified, there was essentially no market for aero-derivative CTGs (like those at Pinckneyville) and little market depth overall. Exh. 60, p. 40, l. 1-11 (Voytas Rebuttal). And, on the Audrain plant alone, AmerenUE saved 135 or 136 million dollars by not following the urging of Mr. Kind, Mr. Rackers, and NRG to purchase it in 2002 (Tr. p. 3212, l. 20-21 (Mr. Voytas), p. 3243, l. 19 (Mr. Kind).

[455] Tr. p. 3243, l. 2-6 (Mr. Kind).

[456] Tr. p. 3243, l. 16-19 (Mr. Kind).

be, but for litigants in this case to suggest a rate base *write-down* based upon the fire sale price AmerenUE was able to pay for the Audrain CTGs is equally improper. Mr. Kind's position brings to mind the cliché "no good deed goes unpunished."

In continuing to point to the NRG Audrain CTGs, both Staff (initially) and Mr. Kind rely on a one and one-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 a low market value for the P & K CTGs. They make this attempt despite the fact that not only did NRG never "offer" to sell the Audrain CTGs at the price discussed in that letter, 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 initially relied upon by Staff and still relied upon by Mr. Kind.[457] Further, the NRG Audrain CTGs and the P & K CTGs are quite dissimilar, and the transmission constraints at Audrain were such that the plant could not be operated commercially at all,[458] and indeed the plant never was operated commercially by NRG.[459]

As noted, the NRG Audrain CTGs provide a poor comparison to the P & K CTGs. The Audrain CTGs are all large frame CTGs[460] 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, and consequently they are dispatched less frequently.[461] The combined Pinckneyville and Kinmundy CTGs consist of two large frame units, four aero-derivative units, and four small frame units.[462] Overall, these units have features (dual-fuel capability at Kinmundy, much better heat rates,

[457] Exh. 60, p. 20, l. 17-26 (Voytas Rebuttal).
[458] Mr. Kind also knew about the transmission constraints. Exh. 131.
[459] Exh. 60, p. 14, l. 20-21 (Voytas Rebuttal); Tr. p. 3218, l. 23-24 (Mr. Voytas).
[460] Exh. 60, p. 9, l. 4-6 (Voytas Rebuttal).
[461] Exh. 60, p. 7, l. 17 to p. 10, l. 8 (Voytas Rebuttal).
[462] Exh. 60, p. 8, l. 20 to p. 9, l. 3 (Voytas Rebuttal).

quick start capability, intraday cycling capability for many of the Pinckneyville units) that make them worth far more than the NRG Audrain CTGs.[463] There is no evidence that Mr. Kind knows anything about any of this, or that he performed any analysis to account for the drastic differences between these plants.[464]

Aside from the dissimilarity of the CTG plants, the NRG indicative proposal was sent by a lower-level staffer at NRG, named Connie Paoletti,[465] which indicated that Ms. Paoletti expected a purchase price of $200 million, or approximately $346/kw (which understates even that price, since it is based upon a plant capability that did not and does not exist, as discussed below),[466] and this price reflected in any event a below-market, ***forced sale price*** that is irrelevant to trying to determine a fair market value for the P & K CTGs.[467] It is axiomatic that the sale of an asset under conditions when the seller is facing bankruptcy[468] would be a forced sale made at below-market prices, not a fair market price sale. It is also 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.[469] NRG, as a financially distressed seller ***was*** under a compulsion to sell, and it is a simple matter of common sense that under those circumstances the financially distressed seller will likely sell assets for less than a fair market price. Mr. Kind's reliance on this "price" to support

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[463] Tr. p. 3110, l. 24 to p. 3111, l. 12 (Mr. Voytas); Exh. 60, p. 9, l. 23 to p.10, l. 8 (Voytas Rebuttal).
[464] Mr. Kind did acknowledge that he had no engineering expertise and that he looked only at prices. Tr. 3238, l. 11; Tr. p. 3241, l. 5-15; Exh. 98, p. 63, l. 25 to p. 64, l. 2 (Kind Deposition). Mr. Rackers had admitted essentially the same things. Exh. 101, p. 87, l. 4-8 (Rackers Deposition).
[465] The letter was signed by Connie L. Paoletti who apparently worked in "origination." Exh. 60, RAV 2-1 (Voytas Rebuttal).
[466] 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. Exh. 60, p. 6, l. 12 to p. 7, l. 5 (Voytas Rebuttal).
[467] Exh. 60, p. 35, l. 21-26. Mr. Kind himself knew that any price quoted by NRG was a forced sale price, because he knew NRG was in financial distress. Exh. 131, quoting Mr. Kind's October 8, 2002 letter to Mr. Voytas, sent just a couple of months after Ms. Paoletti's letter had been prepared.
[468] NRG filed bankruptcy on May 14, 2003 (just 10 months after Ms. Paoletti sent her letter) – Docket No. 03-03632, Bankruptcy Court for the Southern District of New York, filed May 14, 2004.
[469] *Cf.* Missouri Approved Instruction 16.02.

an allegedly lower market price for P & K is therefore misplaced and inappropriate. Indeed, reliance on this "indicative proposal" is entitled to no weight whatsoever, is arguably spurious, and should be entirely disregarded.

Even the price at which NRG's President Redd indicated NRG would sell ($391/kw) is understated[470] That price was based upon the nameplate rating (640,000 kw)[471] when in fact the net summer capability (which is how Messrs. Rackers and Kind priced the Pinckneyville and Kinmundy CTGs) was much lower – just 600,000 kw.[472] At the time of this indicative proposal, Audrain had severe transmission constraints, meaning that at that time it had only salvage value and that purchasing it would have amounted to a gamble of hundreds of millions of dollars.[473] Moreover, according to the MISO, *today*, after new transmission lines and other upgrades to the system have been constructed,[474] the actual outlet capability of the NRG Audrain CTGs is just 578,000 kw.[475] Applying either of the more correct capacity figures to the NRG Audrain CTGs means 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 after subsequently-constructed upgrades).[476] Both prices are in the general range of the price actually paid by AmerenUE for the Pinckneyville and Kinmundy CTGs.[477] Indeed, as corrected to reflect actual facts pertaining to generating and transmission capacity, the Audrain actual offer price and

[470] Exh. 60, p. 21, l. 2-12 (Voytas Rebuttal).
[471] Exh. 60, p. 21, l. 7-8 (Voytas Rebuttal).
[472] Exh. 60, p. 7, l. 12-16 (Voytas Rebuttal).
[473] Exh. 60, p. 5, l. 16-19, p. 15, l. 15 to p. 18, l. 24 (Voytas Rebuttal).
[474] Exh. 60, p. 17, l. 11 to p. 19, l. 4 (Voytas Rebuttal).
[475] Exh. 60, p. 18, l. 25-29 (Voytas Rebuttal).
[476] Exh. 60, p. 21, l. 7-12 (Voytas Rebuttal).
[477] 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, as Mr. Kind admitted (Tr. p. 3243, l. 6).

the price paid for P & K are virtually identical.[478] As mentioned above, NRG's own expert's work showed a market value for P & K *above* what was paid.[479]

e. The State's Proposed Disallowance is Equally Unsupported.

Mr. Brosch, the only other witness now sponsoring a downward adjustment for ratemaking as to P & K, admitted that he had made a comment shortly before the hearing characterizing this issue as the Company's "strongest."[480] The Commission can figure out for itself why Mr. Brosch knew that the Company's position on this issue was strong, but the Company would suggest that Mr. Brosch made that statement because he recognized that the so-called "evidence" the State and OPC had marshaled to try to sustain their proposed disallowances was and is quite weak and fails to carry their burden. Mr. Brosch admitted that FERC had approved the transaction,[481] admitted that he did not himself conduct any type of prudence investigation regarding the pricing of P & K,[482] and admitted that he based his recommendation *entirely* on certain information he asked for that had been provided by AmerenUE in response to a data request,[483] which was shown by the evidence to amount to unscrubbed and unverified data from magazine article clippings.[484] He admitted for example that he had no information about any transmission constraints on the units whose sales were "reported" in the magazine article clippings that he relied upon,[485] that he did not know if any units he eliminated from consideration were similar to P & K,[486] and that on this basis and this

[478] Exh. 60, p. 21, l. 18-19 (Voytas Rebuttal).
[479] Exh. 60, p. 26, l. 1-9 (Voytas Rebuttal).
[480] Tr. p. 3246, l. 19 to p. 3247, l. 3 (Mr. Brosch).
[481] Tr. p. 3247, l. 19 to p. 3248, l. 8 (Mr. Brosch).
[482] Tr. p. 3248, l. 17-20 (Mr. Brosch). It's not clear how he believes he can sustain a prudence disallowance, having not himself conducted a prudence review.
[483] Tr. p. 3249, l. 10-16 (Mr. Brosch); *see* Exhibit 435.
[484] Tr. p. 3085, l. 4-7 (Mr. Voytas).
[485] Tr. p. 3273, l. 2 (Mr. Brosch).
[486] Tr. p. 3274, l. 25 (Mr. Brosch). Again, how could he know anything about the characteristics of those other units since all he knows is that AmerenUE had compiled an unscientific collection of magazine article clippings about CTG sales around the country.

basis alone he was advocating a prudence disallowance of fully 1/3 of the actual cost paid for P & K.[487] He admitted that his only testimony on this issue, dated December 15, 2006, concluded with an invitation for the Commission to consider "additional facts and circumstances supplied by AmerenUE as well as the Staff's prudent [sic] review in finalizing a reasonable rate-making valuation for these assets."[488] He apparently extended this invitation in recognition of the fact that his magazine clippings-based "analysis" proved little.

Of course, Staff's prudence review consists entirely of Mr. Rackers' review, and we know Mr. Rackers is not proposing a prudence disallowance for P & K and, as demonstrated by his deposition (Exh. 101), we also know that Mr. Rackers' review woefully failed to establish any imprudence on AmerenUE's part. Mr. Brosch, in suggesting the Commission look to additional facts and circumstances from AmerenUE, explicitly points to Mr. Voytas's testimony, which was filed six weeks after his testimony was filed, on January 31, 2007.

Among many other things in his extensive testimony, Mr. Voytas explained at length why one cannot rely upon the unverified pricing information reported in magazine clippings, the only source of Mr. Brosch's recommendation. Among the problems are that there may be assumption of debt or other financial aspects of transactions that are not reported in the clippings that drastically change the "reported" price; the clippings tell us nothing about the financial condition of the seller – which also affects whether the transactions were fair market transactions; the clippings tells us nothing about the plant characteristics and capabilities of the plants reported; often the type of unit is not known or reported (large frame, small frame, or aero-derivative), and often things like whether there is dual fuel or quick start capability is not specified.[489] Mr. Voytas testified that magazine-reported information is of little help in

[487] Tr. p. 3275, l. 12 ("288 over 432 is the allowed fraction.") (Mr. Brosch).
[488] Tr. p. 3250, l. 8-13 (Mr. Brosch).
[489] Tr. p. 3205, l. 11-23; p. 3206, l. 16 to p. 3207, l. 3 (Mr. Voytas).

establishing actual terms of the sales and characteristics of the units involved, explained that the market for CTGs is very thin,[490] and stated that it is generally recognized that no two sales of CTGs are alike,[491] and that "the devil is in the details."[492] He testified that superior information on all such matters to make sound comparisons can be obtained from actual Requests for Proposal (RFPs)[493] as were done under his supervision prior to AmerenUE's acquisition of P & K and approved as adequate by FERC,[494] and also prior to the acquisition of Audrain, Raccoon Creek, and Goose Creek from NRG and Aquila in 2006.[495] He also reported at length in his prefiled testimony on the extensive market pricing information developed during the long history of this issue, and the multiple expert studies which established that the price at which P & K were purchased was below market.[496] He thus presented a large body of evidence contradicting the positions of Mr. Kind and Mr. Brosch, as well as the position taken earlier and then abandoned by Mr. Rackers.

f. There is No Credible Evidence that the Price Paid was Not At or Below a Fair Market Price.

Not only have OPC and the State failed to carry their burden, Mr. Voytas's testimony demonstrates in any event that the net book value price paid by AmerenUE was at or below market for these CTGs. As explained at length in Mr. Voytas's testimony, there were extensive FERC proceedings covering eight days of evidentiary hearings on just this one issue, the acquisition of P & K by AmerenUE.[497] Mr. Voytas himself testified for ten hours over two

[490] Tr. p. 3202, l. 14 (Mr. Voytas).
[491] Exh. 60, p. 22, l. 20-21 (Voytas Rebuttal).
[492] Tr. p. 3167, l. 18-19 (Mr. Voytas).
[493] Tr. p. 3170, l. 5-7 (Mr. Voytas.
[494] Exh. 60, p. 27, l. 6-34 (Voytas Rebuttal).
[495] Note that these three "fire sale" acquisitions from bankrupt or distressed sellers form the sole basis for Mr. Kind's "primary" proposed adjustment (Tr. 3240). Note also that the non-fire-sale bids, which were not taken, were for $494/kw and $525/kw. Exh. 60, p. 39, l. 9-20 (Voytas Rebuttal); Tr. p. 3210, l. 1 to p. 3211, l. 21 (Mr. Voytas).
[496] Exh. 60, p. 23, l. 6 to p. 26, l. 25 (Voytas Rebuttal).
[497] Tr. p. 3186, l. 7-9 (Mr. Voytas).

days.[498] In that proceeding NRG, the owner of the Audrain plant, lost what was essentially the same argument now being made to this Commission. Indeed, NRG claimed that its willingness to sell its Audrain CTG Plant at $391 per kilowatt versus the net book value transfer price of the P & K CTG plants ($439.50/kw) meant 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.[499]

In fact, however, the FERC Administrative Law Judge (ALJ) who heard the case 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."[500] The ALJ's Initial Decision[501] 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).[502] Ultimately, the Initial Decision determined that AmerenUE's purchase of the P & K CTGs did not involve any affiliate abuse, was on terms similar to other competitive alternatives, in fact did employ an adequate RFP, and would have no adverse impact on competition.[503]

In summary, the bottom line is that those who propose a rate base adjustment for P & K have engaged in a narrow picking and choosing exercise. Mr. Kind places reliance on a non-binding indicative proposal from a distressed seller that is lower than the price that same

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[498] *Id*.
[499] *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); Exh. 60, p. 27, l. 6-34 (Voytas Rebuttal).
[500] Initial Decision, page 57, ¶ 126. *See* Exh. 60, p. 26, l. 16-25 (Voytas Rebuttal).
[501] The FERC affirmed all essential elements of the Initial Decision – in the FERC's words, the FERC "largely affirm[ed]" the Initial Decision, and only disturbed three areas that do not disturb any of the provisions of the Initial Decision which are the subject of Mr. Voytas's testimony. Order 473, ¶ 34.
[502] *Id*.
[503] Initial Decision at 1-2. Exh. 60, p. 27, l. 6-34 (Voytas Rebuttal). 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.

distressed seller's president indicated was being offered and that is miscalculated because of the failure to account for the transmission problems at the plant. Mr. Kind other "primary position" is to insist that all CTG acquisitions by AmerenUE, regardless of the characteristics or circumstances, should match in price the one-time opportunity AmerenUE had in 2006 to obtain dissimilar large-frame CTGs from two different financially distressed sellers in 2006, by which AmerenUE saved themselves (and ratepayers) hundreds of millions of dollars. Mr. Brosch argues that un-analyzed magazine-reported sales, obviously hand-picked for low numbers, should set the market. Both Mr. Kind and Mr. Brosch ignore the fully audited and approved costs of newly constructed units similar to P & K,[504] and ignore sales of other more comparable units, all to erect a construct of so-called "facts" to support their enormous proposed rate base adjustments.

It has been established by mountains of evidence in multiple filings and proceedings, as summarized in Mr. Voytas's testimony, that AmerenUE paid a fair, at or below-market price for these CTGs when it acquired them on precisely the terms contemplated by the Case No. EC-2002-1 Stipulation. No contrary prudence review or in-depth study and in fact no credible study of any kind reaching a different conclusion is before the Commission, and certainly Messrs. Kind and Brosch have failed to carry their burden to sustain large rate base disallowances for the P & K plants. As Mr. Brosch conceded, this is clearly a very weak issue, and this belief is borne out by Mr. Rackers' abandonment of his adjustment. Consequently, the entire price paid should be included in AmerenUE's rate base.

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[504] *See* Exh. 201 (Staff witness Leon C. Bender's Direct Testimony) and the next section of this brief.

2. Peno Creek.

Like the P & K issue, this one involves acquisition of CTGs by AmerenUE. The four Peno Creek CTGs, however, were constructed by AmerenUE rather than purchased from another company.

The actual cost of construction of this CTG Plant should be included in rate base. An extensive and detailed construction audit was performed under the supervision of Staff's Regulatory Engineer Leon C. Bender, and his conclusion was succinct: "Staff has not identified any construction costs during construction that should not be allowed in rate base."[505] Mr. Bender has 29 years of experience in generation plant design, operation, and evaluation.[506]

A single witness, an economist with no engineering education or experience and no experience with construction or operation of generating plants,[507] who did not conduct an audit like Mr. Bender's (or any audit at all) and who has never been to the Peno Creek plant site,[508] OPC witness Ryan Kind argues for a downward adjustment of this asset's construction cost in rate base. His sole analysis is based upon a single issue, price,[509] with no analysis of characteristics, usefulness, or reliability of the new plant, and he recommends as the appropriate price one isolated number which was compiled by AmerenUE for the cost of construction of a completely different kind of CTG seven years earlier[510] ($390/kw)[511] rather than the actual construction cost of Peno Creek ($570/kw).[512] The effect on the Company's revenue requirement of his recommendation would be approximately $3 million.

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[505] Exh. 201, p. 5, l. 3-4 (Bender Direct).
[506] *Id.*, p. 1, l. 17-28.
[507] Exh. 98, p. 58, l. 2 (Deposition of Ryan Kind); Tr. p. 3238, l. 9-11 (Mr. Kind); Tr. p. 3239 l. 13-21 (Mr. Kind).
[508] Exh. 98, p. 55, l. 1-11 (Deposition of Ryan Kind).
[509] Tr. p. 3356, l. 14-15 (Mr. Kind).
[510] Exh. 60, p. 29, l. 9 to p. 30, l. 11 (Voytas Rebuttal). This estimated price was from a 1995 asset mix optimization study and represented generic installed cost for a large-frame CTG based on 1995 information and has no relevance to Peno Creek, which went into operation in 2002 and consisted entirely of aero-derivative units. *Id.*
[511] Tr. p. 3349, l. 7 (Mr. Kind); Exh. 60, p. 29, l. 6 (Voytas Rebuttal).
[512] Exh. 60, p. 4, l. 12-13 (Voytas Rebuttal).

The Peno Creek plant consists entirely of high quality aero-derivative CTGs, with unique and uniquely valuable characteristics. The four aero-derivative units have dual-fuel capability to use natural gas or oil, are capable of reaching full output in just eight minutes, can be used to comply with operating reserve requirements of MISO,[513] have intra-day dispatch capability, have low operation and maintenance expenses, have remote operation capability allowing prompt market response, have excellent heat rates, and have low carbon dioxide emissions.[514] Aero-derivative units are desired because of all these characteristics, and the ones chosen for this plant (Pratt & Whitney FT8s) were determined to be the most competitive available in terms of construction cost, startup costs, operating expense, and various qualitative issues.[515]

AmerenUE took additional steps to minimize the costs of adding these highly valuable CTGs to its system. It arranged to use Chapter 100 bonds and a lease with the City of Bowling Green, providing annual savings of $1.8 million in personal property taxes, and a twenty-year net present value of these savings of approximately $33 million.[516] Also, the Company was able to take advantage of "bonus depreciation" for this plant, with substantial additional savings,[517] all of which reduce AmerenUE's cost of service to the benefit of customers.

Prior to construction of Peno Creek, AmerenUE had 200-300 megawatts of CTGs, but most were 1970s vintage, and none had the capabilities that these aero-derivative units have as described above.[518] "Load following" or adjusting to hourly fluctuations in load was attempted with coal-fired plants, but required significant charges in terms of capital cost and operating parameters. Older CTGs were generally not equipped for load following operations.[519] In

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[513] Exh. 60, p. 30, l. 16-21 (Voytas Rebuttal).
[514] Exh. 60, p. 33, l. 11-14 (Voytas Rebuttal).
[515] Exh. 60, p. 31 (HC table) (Voytas Rebuttal).
[516] Exh. 60, p. 32, l. 6-10 (Voytas Rebuttal).
[517] Exh. 60, p. 32, l. 10-15 (Voytas Rebuttal).
[518] Tr. p. 3328, l. 3-6 (Mr. Voytas).
[519] Tr. p. 3328, l. 7-9 (Mr. Voytas); Tr. 3338, l. 2 to p. 3341, l. 2 (Mr. Voytas).

addition to the flexibility of operation benefits already mentioned, the Peno Creek plants provided various reliability benefits to AmerenUE's system. These included power and voltage support where none had existed before, and the new units augmented the existing system and provided real and reactive power and voltage support to the area as needed for a variety of system operation conditions.[520] The new CTGs are particularly useful in dealing with the summer "double-hump peak" of mornings and evenings, since they have intra-day cycling capability not present in coal-fired generation or large-frame CTGs.[521]

Staff's detailed construction audit involved monitoring the progress of the project during construction, reviewing contracts and change orders, evaluating all costs incurred, making numerous trips to the site, and having numerous meetings and telephone consultations with AmerenUE managerial personnel.[522] As mentioned, all this was done or supervised by an engineer with extensive experience building, operating, and evaluating generation plants, Mr. Bender, and he concluded that all costs incurred should be allowed in rate base.[523]

Economist Mr. Kind advanced as his only argument that in a filing AmerenUE had made in another case in 1999, a figure for possible construction cost of CTGs of $390/kw was mentioned.[524] The evidence established that in fact this number was for the much cheaper large-frame CTG, which lacks all of the operation, maintenance, and qualitative advantages of the Peno Creek aero-derivative units,[525] and that cost estimate was derived from a study conducted in 1995, seven years before Peno Creek was constructed in 2002.[526] Mr. Kind's argument on this issue, for pricing all CTGs at that $390/kw price, is essentially the same one he made in the

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[520] Exh. 60, p. 32, l. 18 to p. 33, l. 10 (Voytas Rebuttal); Tr. 3338, l. 2 to p. 3339 l. 1 (Mr. Voytas).
[521] Tr. p. 3338, l. 16-23 (Mr. Voytas).
[522] Exh. 201, p. 3, l. 10 to p. 4, l. 3 (Bender Direct).
[523] *Id.* at 5; *see id.* at 1. Mr. Bender's construction audit covered all AmerenUE generating plants constructed since the last rate case, comprising units 1, 2, 3, and 4 at Peno Creek and units 2, 3, 4, and 5 at Venice. *Id.* at 3.
[524] Tr. p. 3349, l. 5-18 (Mr. Kind).
[525] Exh. 60, p. 30, l. 8-10 (Voytas Rebuttal); Tr. p. 3344, l. 25 to p. 3345, l. 8 (Mr. Voytas); Tr. p. 3328, l. 1-13 (Mr. Voytas); *see* Tr. p. 3338, l. 2 to p. 3341, l. 14 (Mr. Voytas).
[526] Exh. 60, p. 30, l. 2-4 (Voytas Rebuttal).

Metro East case, which was strongly rejected by this Commission in favor of a figure of $471/kw for CTG acquisition (undifferentiated as to type) as mentioned in the prior subsection of this brief respecting P & K.

Mr. Kind also argued that Peno Creek was built in a hurry because of what he claimed were strategic planning mistakes by AmerenUE, and he asserted that this caused higher costs.[527] Company witness Richard Voytas contradicted this, stating that it is not true that construction of a generating plant on a short time frame is necessarily more expensive.[528] Under extensive questioning by Commissioner Gaw, Mr. Kind admitted that his sole basis for arguing against full inclusion of the actual cost of Peno Creek was that he thought that different planning should have been done so that "better" CTGs with longer delivery times could have been purchased to be installed by the summer 2002 date when they were needed.[529] By "better" he, the economist, said he meant that initial construction was "lower-cost."[530] When given an opportunity by Commissioner Gaw to do so, Mr. Kind declined to challenge Mr. Voytas's testimony on AmerenUE's decision-making and the value to the system of the Peno Creek aero-derivative units, saying he had "nothing to add" on those subjects.[531]

Mr. Kind's attempt to focus solely on price, and in doing so to rely on a single suggested cost for CTGs that was derived years earlier and applied then only to cheaper large-frame CTGs, not to aero-derivative units with multiple special features like those at Peno Creek which make them uniquely suited to serve AmerenUE's system as it has evolved, represents a complete failure to prove his assertion that the cost of the Peno Creek plant was imprudent. As mentioned in the prior subsection of this brief respecting P & K, the Commission, in reviewing prudence,

[527] Tr. p. 3351, l. 17 to p. 3353, l. 1 (Mr. Kind).
[528] Tr. p. 3321, l. 25 (Mr. Voytas).
[529] Tr. p. 3355, l. 5 to p. 3356, l. 9 (Mr. Kind).
[530] Tr. p. 3356, l. 15 (Mr. Kind).
[531] Tr. p. 3360, l. 17-18 (Mr. Kind).

does not use hindsight to later second-guess the decision management has made.[532] 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.[533]

Mr. Kind has failed to meet his burden to establish that there exist any imprudently incurred costs relating to Peno Creek, and indeed, both Staff and AmerenUE have proved to the Commission that the costs of Peno Creek were prudent. They should be fully allowed in rate base.

G. Depreciation.

1. The Positions Reflected in the Non-Unanimous Stipulation Between the Company and the Staff Should be Adopted.

The Company and the Staff entered into and filed a Non-Unanimous Stipulation and Agreement Regarding Certain Depreciation Issues (Depreciation Stipulation) that addresses and resolves, at least as between them, many of the depreciation issues in this case, primarily involving the appropriate survivor curves and net salvage percents to be used to determine the depreciation rates for various accounts. Because the Depreciation Stipulation was opposed in part by both MIEC and OPC, pursuant to the Commission's rules it must be considered to be merely the position of the signatory parties. 4 CSR 240-2.115(D). However, this joint position of the Staff and the Company is reasonable, is fully supported by the testimony provided by the Staff and/or the Company, and ought to be adopted by the Commission in this case. A discussion of each of the substantive provisions of the Depreciation Stipulation follows.

The first substantive provision of the Depreciation Stipulation, paragraph 3(a), provides that the Staff's recommended net salvage percents for Steam and Hydraulic Plant will be used to calculate depreciation rates for those accounts. The enumerated net salvage percents are fully

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[532] *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).
[533] *See, e.g.,* State ex rel. GTE v. Pub. Serv. Comm'n, 537 S.W.2d 655 (Mo. App., W.D. 1976).

supported by the depreciation study submitted in this case by Staff witness Jolie L. Mathis,[534] and the Company agrees that the net salvage percents Ms. Mathis has recommended for the Steam and Hydraulic Plant accounts are reasonable. MIEC opposes the net salvage percents recommended by Ms. Mathis and endorses a completely different approach to net salvage, which will be rebutted in detail in subsection 4 of this portion of the Company's brief. OPC also submitted an objection to this paragraph of the stipulation, but did not address the net salvage percents for Steam or Hydraulic Production plant in any of its testimony. Consequently, the objections of MIEC and OPC to this portion of the stipulation should be rejected.

In addition, paragraph 3(a) of the Depreciation Stipulation provides that the Company shall not seek to recover from its customers either terminal net salvage applicable to its fossil plants or the difference between the book reserve balance and the theoretical reserve balance. All of the other parties who submitted testimony in this case on depreciation issues opposed AmerenUE's proposal to collect terminal net salvage costs for its fossil plants, primarily based on the Commission's recent decision in Case No. ER-2004-0570 involving The Empire District Electric Company. Even though the Company believes that the collection of terminal net salvage costs in depreciation rates is fully supported by depreciation principles,[535] it has agreed to drop its request to recover such costs in this case. In addition, the Company agrees that it should not collect from customers the difference between the book reserve balance and the theoretical reserve balance for any account in this case.

The second substantive paragraph of the Depreciation Stipulation, paragraph 3(b), provides that for accounts 341-346, Other Production Plant accounts, a 40-R4 survivor curve[536]

[534] Exh. 222, Schedule JLM-2 (Missouri Public Service Commission Staff witness Jolie L. Mathis' Direct Testimony).
[535] Exh. 69, p. 17-19 (AmerenUE witness William M. Stout's Direct Testimony).
[536] A 40-R4 survivor curve describes plant with an average service life of 40 years, and an Iowa curve shape identified as "R4."

and a (-5%) net salvage percent shall be used. The (-5%) net salvage rate is supported by the depreciation study submitted by Company witness John Wiedmayer in this case.[537] The use of a 40-R4 survivor curve for each of the Other Production Plant accounts represents a compromise between the lives and curves recommended by Ms. Mathis and Mr. Wiedmayer for each of these accounts.[538] For example, in the account with the largest balance, Account 344, Ms. Mathis recommended the use of a 45-R4 survivor curve (which reflects an average service life of 45 years for the account) and Mr. Wiedmayer recommended the use of a 35-SQ survivor curve (which reflects an average service life of 35 years). The 40-R4 curve (which reflects an average service life of 40 years and Ms. Mathis' chosen Iowa curve shape) is a compromise between the positions supported by the depreciation studies of Ms. Mathis and Mr. Wiedmayer.

The next provision of the Depreciation Stipulation, paragraph 3(c), provides that the interim survivor curves for Accounts 321-325, Callaway Plant accounts, as supported by the depreciation studies of both Mr. Wiedmayer and Ms. Mathis, will be adopted. To account for net salvage related to interim retirements, an additional .2% will be added to the depreciation rate for Account 322, and an additional .1% will be added to the depreciation rates of the other nuclear plant accounts. Although this differs slightly from the net salvage recommendations contained in Ms. Mathis' depreciation study, at the hearing Ms. Mathis testified that these allowances for net salvage are reasonable.[539]

The next paragraph of the Depreciation Stipulation adopts the survivor curves and net salvage percents supported by Mr. Wiedmayer's depreciation study for Transmission Plant, Distribution Plant and General Plant. The only exception is Account 368, Distribution Plant, for

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[537] Exh. 72, Sch. JFW-E1, p. III-6 (AmerenUE witness John F. Wiedmayer's Direct Testimony).
[538] *See* Exh. 222, Sch. JLM-2, p. 3 for comparisons of Staff and Company positions on each account.
[539] Tr. p. 3751, l. 6-10 (Ms. Mathis).

which the survivor curve and net salvage percent supported by Ms. Mathis' study are adopted.[540] MIEC and OPC object to the net salvage percents for these accounts. MIEC applies its alternative approach to net salvage to these accounts. MIEC and OPC also apply inappropriate adjustments to the net salvage analysis. Both MIEC's alternative approach and the inappropriate net salvage analyses are described in subsection 4 of this portion of the Company's brief.

The next paragraph in the Depreciation Stipulation requires AmerenUE to transfer $82,067,828 of accumulated depreciation reserve from its Distribution Plant accounts to its General Plant accounts. This transfer will correct reserve imbalances resulting from depreciation accrual rates that have been too high for Distribution Plant and too low for General Plant for many years. As Mr. Wiedmayer explains in his direct testimony, the Company's current depreciation rates were initially set in 1983, and so they do not reflect the longer lives of distribution assets that have resulted from improved maintenance practices, better equipment and new protective devices developed in subsequent years. Conversely, the depreciation rates do not reflect shorter lives for General Plant items, such as personal computers, which were previously classified as Office Furniture and Equipment and depreciated over a 28-year average service life. In contrast, most companies depreciate personal computers over a 3-5 year period.[541] The transfer will offset the over-accrual in the Distribution Plant Accounts with the under-accrual in the General Plant accounts and put both accounts into better balance with no impact on depreciation rates.

Finally, the Depreciation Stipulation requires the Venice Plant removal costs of $1,980,000 to be recovered through a depreciation reserve transfer from an over-accrued plant account. No party has opposed this provision of the Depreciation Stipulation.

[540] Exh. 222, Sch. JLM-2, p. 3 (Mathis Direct).
[541] Exh. 72, p. 14, l. 13-14 (Wiedmayer Direct).

The joint positions of the Staff and the Company contained in the Depreciation Stipulation represent a reasonable resolution of those issues, and they are fully supported by Staff and/or Company testimony filed in this case. As a consequence, the Commission should adopt these recommendations in establishing depreciation rates for the Company.

2. The Life Span Method is a Sound, Mainstream Depreciation and Regulatory Policy and Should be Adopted.

One of the major areas of disagreement between the Company and Staff involves the use of the "life span" method in calculating depreciation rates for categories of property that are components of AmerenUE's Steam and Hydraulic Production plants. The life span method simply recognizes the reality that generating plants will eventually be retired, and when a plant is retired, all of its components must be simultaneously retired. Using this method, survivor curves reflecting interim retirements of the component parts of generating plants are truncated on the estimated retirement date of the plant, and as a consequence the average service life for each component is reduced to reflect the plant's retirement.[542] Use of the life span method is a mainstream depreciation practice, endorsed by both the NARUC Depreciation Manual and Depreciation Systems, the well-respected text on depreciation authored by Wolf and Fitch. (Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Iowa State University Press, 1994.) According to the testimony of AmerenUE witness William Stout, the life span method is used by most, if not all, other state commissions.[543] It is also endorsed by most of the depreciation experts who appeared in this case. For example, James T. Selecky, the depreciation expert appearing on behalf of MIEC, agreed that life span treatment was appropriate for AmerenUE's coal-fired plants, and proposed depreciation rates based on that method.[544] Even Staff witness

[542] Exh. 69, p. 12, l. 4-6 (Stout Direct).
[543] Exh. 70, p. 8, l. 3-4 (Stout Rebuttal).
[544] Tr. p. 3755, l. 3-9 (MIEC witness Jim Selecky).

Mathis agreed that AmerenUE's coal plants are life span property.[545] Apparently the only reason Ms. Mathis is unwilling to apply the life span method is that she believes that the retirement dates for the Company's fossil plants are too uncertain.[546]

But the evidence in this case shows that AmerenUE does have reasonable estimates of the retirement dates for each of its four coal-fired plants. Mark Birk, AmerenUE's Vice President of Power Operations, estimated the following retirement dates[547] for each plant:

Facility	**Estimated Retirement Date**	**Approximate Age At Retirement**
Meramec Plant	2021	63 years
Sioux Plant	2027	60 years
Labadie Plant	2033	61 years
Rush Island Plant	2037	60 years

In his testimony, Mr. Birk stated that these estimated retirement dates were based on (a) the age and condition of each major plant component, (b) the service history of each facility and the expected future conditions, (c) anticipated near term capital investment for each facility, and (d) the time and resources required to permit and construct replacement base load production capacity.[548] Consideration was also given to the potential for increasingly stringent future environmental requirements, the potential for future development of new generation technologies which may be more efficient and/or cleaner, and the finite life associated with thick-walled components common to all of the generating plants, such as boiler drums and headers.[549] At the hearing, Mr. Birk elaborated on considerations specific to each plant that supported his estimated retirement dates. For example, when he was asked specifically why 2027 was an appropriate estimated retirement date for the Sioux Plant, Mr. Birk testified as follows:

[545] Tr. p. 3734, l. 17-20 (Ms. Mathis).
[546] Exh. 223, p.8, l. 15-22 (Mathis Surrebuttal).
[547] Mr. Birk originally provided an average estimated retirement date for all of the plants of 2026. In response to criticism of this approach by other parties, Mr. Birk provided a specific estimated retirement date for each generating plant in his rebuttal testimony.
[548] Exh. 26, p. 2, l. 12-14 (Birk Rebuttal).
[549] Exh. 26, p. 1, l. 17-23 (Birk Rebuttal).

> …the main drivers at the Sioux plant, which the significant pieces of equipment involve cyclones, and the cyclones are, basically, for lack of a better term, the burners in each of those boilers.
>
> We've had cyclone replacements. Both Sioux units were put into service…in…1968. We've replaced the cyclones once on those—both of those units. That was about the mid '80's.
>
> We currently have cyclone replacements scheduled for those units late in this decade. An the feeling would be based upon the average life we see on cyclones that those same cyclones would—would come up for replacement again around the 2027 time frame, somewhere in there.
>
> And those—that is a significant expense on those units. And that, coupled with where we see potentially the environmental landscape being at that time, led us to believe that that's a pretty good assumption at this point.[550]

When asked why 2037 was the appropriate estimated retirement date for the Rush Island Plant, Mr. Birk testified as follows:

> Rush Island went into service, Units 1 and 2, in 1976 and 1977 respectively. We currently have a 93-day outage going on at our Rush Island unit 1 facility where we're replacing the economizer, the reheater, the lower slopes. That is an approximately $50 million job.
>
> We've just also within the last couple of years replaced the HPIP and LP turbines. Or the LP turbines were not replaced yet at Rush Island. They're scheduled to be replaced.
>
> And our intention is that in another 30 years, those will come up for replacement again. When we look at that coupled with the potential for some type of carbon—tax or carbon issue, it—it becomes pretty clear to us that—that we're going to be nearing end of life on those facilities.[551]

Mr. Birk also provided facility-specific justifications for the estimated retirement dates of the Labadie and Meramec plants.[552]

Mr. Birk's testimony regarding AmerenUE's coal-fired plants was bolstered by information provided by Mr. Stout on the retirements of steam production units across the utility industry. In Schedule WMS-3 attached to his direct testimony[553] Mr. Stout provided a tabulation of the actual life spans of nearly 200 retired steam production units. The average life span for these units was 46 years, which is considerably shorter than the life spans of 60 to 63

[550] Tr. p. 3648, l. 13 to p. 3649, l. 19 (Mr. Birk).
[551] Tr. p. 3650, l. 13 to p. 3651, l. 2 (Mr. Birk).
[552] Tr. p. 3647, l. 22 to p. 3650, l. 14 (Mr. Birk).
[553] Exh. 69, Sch. WMS-3 (Stout Direct).

years estimated by Mr. Birk for AmerenUE's four coal-fired plants. This industry data clearly supports the reasonableness of AmerenUE's estimated retirement dates for its coal-fired plants.

None of this information provides sufficient certainty for Ms. Mathis, and apparently there is no way any utility ever could meet the standard of certainty Ms. Mathis would require. She points out that "[d]etermination of the *exact* timing of the retirement of a particular facility can only be made relatively close to the time of its anticipated retirement date. Until that time, many variables such as power supply replacement, technology improvements, market conditions, and regulatory requirements change over time. For these reasons, the final retirement date is uncertain."[554] At the hearing, Ms. Mathis agreed that this type of uncertainty would apply to *any* big fossil plant owned by *any* electric utility.[555] As a consequence, in Ms. Mathis' view, as a practical matter, no utility should ever be able to treat its steam production plant as life span property due to every utility's inability to project *exact* retirement dates for its plants. Of course, Ms. Mathis' view stands in sharp contrast to the rest of the world in which most, if not all, states treat steam production plants as life span property despite the fact that estimates of retirement dates must be used.

The truth is that having absolute certainty about the exact retirement date of a plant is not a prerequisite to utilization of the life span method in calculating depreciation rates. Where a utility has reasonable, and reasonably supported estimates of plant retirement dates, as AmerenUE clearly has in this case, the life span method is the most appropriate approach to depreciating components of the plants and should be used.

Ms. Mathis has compounded the consequences of her failure to use the life span method by simply adopting survivor curves for fossil plant accounts that are the same as or very nearly the same as those developed in this case by AmerenUE witness John Wiedmayer (excluding the

[554] Exh. 223, p. 8, l. 18-22, emphasis supplied (Mathis Surrebuttal).
[555] Tr. p. 3735, l. 15 to p. 3736, l. 3, emphasis added (Ms. Mathis).

truncation of those curves due to Mr. Wiedmayer's application of the life span method). These survivor curves are based on data related to *interim* retirements only—that is, retirements of a particular plant component that occur before the retirement of the whole plant.[556] These are perfectly appropriate survivor curves to use where the life span method is being applied and the curves are truncated at the point where the plant is expected to be retired. However, if the life span method is not being used, the survivor curves for these accounts should reflect both interim and final retirement data, which would decrease the indicated average service lives to more representative levels and increase the depreciation rates for these accounts. Since Ms. Mathis has relied on interim retirement data only but included no truncation due to the retirement of the plants, she has materially over-estimated the average service lives for these accounts and understated the depreciation rates, even if one were to assume that her rejection of the life span approach is appropriate.

Ms. Mathis' rejection of the life span method and her use of survivor curves based only on analyses of interim retirements leads to patently unfair, and even absurd results. For example, for Account 315, Accessory Electric Equipment, which contains plant components such as controls, relays, cables, motors, circuit breakers and storage batteries, Ms. Mathis has estimated an average service life of *90 years*.[557] That would mean that if a motor or circuit breaker from this account were installed in a plant today, Ms. Mathis is estimating that on average it would last until 2097![558] And since the maximum life based on the R-1 survivor curve used by Ms. Mathis for this account is 201% of the average service life, Ms. Mathis is in effect estimating a maximum life for certain individual items in this account of 180 years.[559] That would mean that

[556] Tr. p. 3737, l. 19-21 (Ms. Mathis).
[557] Tr. p. 3739, l. 3-18 (Ms. Mathis).
[558] Tr. p. 3739, l. 19-22 (Ms. Mathis).
[559] Tr. p. 3766, l. 23-25 (Ms. Mathis).

some items of this property installed today would be expected to last until *2187* if Ms. Mathis' estimates are correct.[560]

Of course it is absurd to think that items such as plant motors or circuit breakers could have average service lives or maximum lives as long as those Ms. Mathis has estimated, but it is equally unreasonable to assume that the generating plants in which those items are installed will last that long, given the evidence AmerenUE has provided to support its estimated retirement dates. In 2097 the Company's four coal-fired plants would be between 120 and 139 years old, far older than any reasonably anticipated lives for these plants. In 2187 these plants would be between 210 and 229 years old. By failing to truncate her survivor curves Ms. Mathis has effectively assumed that AmerenUE's coal-fired plants will last beyond these dates, or have infinite lives, a patently unreasonable assumption.

Based on the foregoing, the Commission should reject Ms. Mathis' significantly flawed approach to calculating the depreciation rates for the components of AmerenUE's steam and hydraulic production plants, and adopt the widely recognized life span method for these accounts, as recommended by Messrs. Stout and Wiedmayer, as supported by the authoritative depreciation texts, and as used by most if not all other states.

3. It Should Not be Assumed that the Callaway Plant Operating License will be Extended.

A second significant area of disagreement between the Company and Staff, as well as various other parties, is the estimation of the life span of the Callaway Nuclear Plant. The Company continues to use a plant life span of 40 years, ending in 2024, to calculate depreciation rates for Callaway Plant components. 2024 is the date of the expiration of the current operating license for the Callaway Plant issued by the Nuclear Regulatory Commission (NRC). The Staff

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[560] These dates are particularly unreasonable given the fact that the Company's actual data shows that the very *longest lived* items from this account on AmerenUE's books have only remained in service for 63 years, far shorter than Ms. Mathis' recommended *average* service life of 90 years. (Tr. p. 3743, l. 20 to p. 3744, l. 4).

and other parties assume that the plant's license life will be extended by the NRC for an additional 20 years, and so they recommend the use of 2044 as the ending date for the life of the plant.[561]

AmerenUE's Chief Nuclear Officer, Charles Naslund, provided testimony on this issue. Mr. Naslund testified that it is premature to seek a license extension for the Callaway Plant at this time, since the plant is only just over halfway through the period covered by its initial 40-year operating license.[562] Mr. Naslund testified that it would be appropriate to make a decision as to whether or not to seek a 20-year extension of the operating license approximately 10 years prior to the expiration of the initial license, or around 2014.[563] Mr. Naslund stated that the Company is engaged in extensive data gathering, including monitoring critical plant components for life impacts due to exposure to radiation and high temperature. He stated that the single most critical consideration in determining whether relicensing may be feasible is the condition of the reactor vessel itself, including neutron embrittlement of the vessel wall.[564] Mr. Naslund also enumerated several other uncertainties that may impact AmerenUE's ability to relicense the plant. These include the potential for a terrorist attack on a nuclear plant anywhere in the world, lack of adequate water supplies in the Missouri River to cool the plant, political changes, and nuclear safety issues.[565]

Some parties have argued that AmerenUE's recent replacement of the steam generators and turbines in the Callaway Plant is a clear indication that AmerenUE intends to seek a license extension from the NRC. State witness Brosch even goes so far as to recommend that if the

[561] Although there is no certainty that 2044 will be the *exact* date of final retirement of the Callaway Plant, it is noteworthy that Staff witness Mathis has no qualms about using this date in conjunction with the life span method in her determination of the nuclear plant depreciation rates.
[562] Exh. 47, p. 9, l. 7-13 (AmerenUE witness Charles Naslund's Direct Testimony).
[563] Tr. p. 4241, l. 3-24 (Mr. Naslund)
[564] Exh. 47, p. 9, l. 16-19 (Naslund Direct).
[565] Exh. 48, p. 2, l. 15-21 (Naslund Rebuttal).

depreciable life of the Callaway Plant is not extended to 60 years, the capital investment for these items should not be included in AmerenUE's rate base.[566] However, Mr. Naslund testified that these replacements were necessary just to allow the Callaway Plant to operate safely and economically to the end of its 40-year life. Although these replacements would also help enable the plant to operate through a 20-year license extension, as Mr. Naslund said in his interview with KOMU news,[567] there are many other operational issues that will have to be resolved before a license extension can be considered. Specifically, Mr. Naslund noted that there are approximately 130,000 components, and miles of cable and piping, originally specified for a 40-year life by the architect/engineers of the plant that would have to be re-assessed and potentially replaced. AmerenUE already knows that most of the buried pipe systems at the plant, the reactor vessel head, and numerous welds in the reactor coolant system would have to be replaced if the license were to be extended.[568]

Mr. Brosch also suggests that O&M expenses are being incurred at the Callaway Plant simply to allow a license extension for the plant.[569] However, Mr. Naslund testified that the O&M costs currently being incurred at the plant are required to meet NRC and engineering standards applicable for the current 40-year life of the plant. These expenses are absolutely not being incurred to facilitate a life extension for the plant.[570] Mr. Naslund testified that AmerenUE is taking steps to keep the option open of requesting a license life extension, but it is simply too early to make that decision.[571]

[566] Exh. 501, p. 46, l. 11 to p. 50, l. 6 (Brosch Direct).
[567] Tr. p. 4217, l. 9-11 (Mr. Naslund).
[568] Exh. 40, p. 3, l. 12-17 (Naslund Rebuttal).
[569] Exh. 501, p. 49, l. 12 to p. 50, l. 6 (Brosch Direct).
[570] Exh. 40 p. 4, l. 3-11 (Naslund Rebuttal).
[571] Similarly AmerenUE recently announced that it has signed an agreement with Unistar Nuclear to prepare a construction and operating license application (COLA) for filing with the NRC to preserve the option of building a second unit at Callaway, if that decision is later determined to be the appropriate resource planning decision.

The Staff, OPC, and MIEC all argue that a 20-year extension of the Callaway license should be assumed since, based on information they downloaded from the NRC website, numerous other utilities that own nuclear plants have either received license extensions, filed license extension applications, or filed "letters of intent" indicating that they expect to file license extension applications.[572] However, these parties have provided little or no information about how depreciation rates for companies in other states have been impacted by these events. Mr. Selecky, the witness for MIEC, cited just two examples of utilities whose depreciation rates for nuclear plants have been reduced at any point prior to the granting of a license extension by the NRC.[573] OPC witness Dunkel cited a single case from Indiana, but apparently in that case the Commission did not change the depreciation rate for the nuclear plant until *after* the NRC extended the license.[574] At the hearing, Mr. Wood admitted that the letters of intent to seek license extensions are revocable, and that he had no idea whether state commissions were reducing depreciation rates on the strength of these letters of intent, or even pending applications to extend the license lives of other nuclear plants.[575] The bottom line is that notwithstanding the fact that many utilities have expressed an intention to seek license extensions for their nuclear plants, there is little evidence that Commissions in other jurisdictions are extending depreciation lives for nuclear plants that have not received license extensions from the NRC, or that it would be appropriate for this Commission to do so.

As a practical matter, AmerenUE believes that there is good reason not to extend the depreciation life of the Callaway Plant prematurely. In terms of impact on customers, the consequences of incorrectly assuming that a license extension will be granted are considerably

[572] Exh. 707, p. 22, l. 4-16 (Selecky Direct); Exh. 401, p. 5, l. 7-16 (Dunkel Direct); Exh. 2431, p. 12, l. 3 to pie chart on p. 14 (Wood Direct).
[573] Exh. 707, pp. 22-23 (Selecky Direct).
[574] Exh. 401, p. 9, l. 11-19 (Dunkel Direct).
[575] Tr. p. 3759, l. 3-13 to p. 3761, l. 1-14 (Mr. Wood).

more severe than the consequences of using a 40-year life until the potential for a license extension becomes more certain. If a license extension is assumed in setting depreciation rates and then no license extension is ultimately granted, AmerenUE will be left with a large undepreciated balance that will have to be recovered after the Callaway Plant is retired in 2024 from customers who are not receiving service from the plant. This is a very unfair result from the point of view of those customers. In contrast, if no license extension is assumed in this case, but then later (say, in 2014) a license extension application is filed and a life extension becomes more certain, the depreciation rates can be reduced with relatively little customer impact. And in that case, only customers who have actually benefited from the Callaway Plant will have to pay depreciation rates associated with the plant.

It is also worth noting that the Commission's rules require the use of the expiration date for the current NRC license in calculating the amount for nuclear plant decommissioning funding. *See* 4 CSR 240-3.185. This is required because the Commission wants to rely on the certainty of an existing license period to ensure that the proper amount of decommissioning costs is collected over the life of each nuclear plant from the customers who benefit from the plant. The exact same considerations suggest that the Commission should rely on the term of the existing NRC license in establishing the life of the Callaway Plant for depreciation purposes. It is no less important for the original cost of the plant to be properly allocated to customers who benefit from the plant than it is for decommissioning costs to be allocated to such customers. For this reason and the others explained above, the Commission should retain the existing 40-year life span for the Callaway Plant unless and until extension of the NRC license becomes more certain.

4. MIEC's and OPC's Attempt to Effectively Depart From Sound Commission Decisions on Net Salvage Should be Rejected.

The Company and Staff have agreed on net salvage percentages for each plant account, consistent with the Commission's recent decisions concerning net salvage. However, MIEC and OPC both oppose a number of these net salvage percentages, principally those for Transmission, Distribution, and General Plant, based on positions that are at odds with the Commission's previous decisions. MIEC witness Selecky's primary position is to use a five-year average of actual net salvage expense and thereby treat net salvage on a cash basis rather than an accrual basis.[576] This is precisely the position that the Commission resoundingly rejected in the recent Laclede depreciation proceeding, Case No. GR-99-315, and confirmed subsequently in The Empire District Electric Company case, Case No. ER-2004-0570. As the Commission may recall, the Laclede case played out over the course of approximately six years, and culminated in an exhaustive examination of all issues surrounding net salvage in a three-day hearing. The Commission explicitly rejected the "expense" approach to net salvage, which is exactly the approach advocated by Mr. Selecky in this case, and adopted the well-recognized, mainstream approach of accruing net salvage costs during the life of the related assets.[577] The Commission confirmed this approach in the subsequent Empire case. The Commission should reject Mr. Selecky's attack on the Commission's well-reasoned approach to this issue and follow its decision in the Laclede and Empire cases.

Mr. Selecky's fall-back position, which is the same as OPC witness Dunkel's primary position, is that even if net salvage is treated as an accrual item, the standard calculation of net salvage should be changed. Specifically, the effect of past inflation should be stripped out of the

[576] Exh. 707, p. 37, l. 5-8 (Selecky Direct).
[577] Report and Order, Case No. GR-99-315 (Jan 11, 2005). The accrual approach to net salvage is also supported by the NARUC depreciation manual, Depreciation Systems, the text by Wolf and Fitch, and the vast majority of other state commissions.

calculation and Mr. Selecky's (or Mr. Dunkel's) much lower prediction of what future inflation might be should then be added back in. This position also runs counter to the Commission's decision in the Laclede and Empire cases, and in fact every case in which the Commission has provided an allowance for net salvage using the traditional (accrual) approach. The Commission has never taken the unusual step of stripping out the impact of actual, historic inflation and substituting a prediction of what a witness believes inflation is likely to be in the future.

In addition, as Mr. Stout points out, there are significant technical flaws with the calculations that Mr. Selecky and Mr. Dunkel have submitted. Both witnesses overstate the average age of historical retirements and understate the average age of future retirements. This results in the removal of far too much inflation from the historic net salvage percents and the addition of far too little inflation to the future net salvage percents. If these errors are corrected, Mr. Selecky and Mr. Dunkel should be increasing, not decreasing the net salvage percents.[578] For this reason, Mr. Selecky's and Mr. Dunkel's recommendations to reformulate the traditional calculation of net salvage costs should be rejected and the net salvage percents stipulated by the Company and Staff should be adopted.

5. 10 CSR 240-10.020.

AmerenUE has cited 4 CSR 240-10.020 as additional support for its rate increase request. That rule essentially requires utilities to provide their customers with a 3% annual credit to reflect income from investment of the money in the utility's depreciation reserve account. The rule applies whether or not the utility's depreciation reserve account is represented by a fund earmarked for that purpose. AmerenUE pointed out that neither the Commission nor utilities have followed this rule in recent years. Instead of providing customers with a 3% credit, the Commission has subtracted accumulated depreciation reserve from the utilities' investment in

[578] Exh. 70, p. 11, l. 23 to p. 14, l. 11 (Stout Rebuttal).

rate base in calculating the return provided to utilities' shareholders.[579] AmerenUE witness Gary Weiss calculated that if the rule was applied in this case, AmerenUE's revenue requirement would be increased by approximately $360 million.[580] AmerenUE is not requesting any increase to its revenue requirement based on the application of the rule, but is merely citing the rule as additional support for the amount of revenue requirement increase it is requesting, as modified by the settlements entered into by the parties.

Some parties have argued that the 3% credit to customers is *in addition* to the credit customers get from subtracting accumulated depreciation reserve from the Company's original investment in rate base. However, as Mr. Weiss testified, that would be an illogical double counting of the credit due to customers.[581] Mr. Weiss' view is supported by the language in the Commission's order in Case No. 10,723 which implemented the rule. The Commission stated: "It is obvious, however, that if the utilities 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."[582] This language makes it crystal clear that the rule was never intended that the utility should *both* provide a 3% credit and reduce its investment in rate base by accumulated depreciation. As a consequence this argument must be rejected.

H. Metro East.

Too much ink has been spilled on this issue already, but since Mr. Kind seems intent on litigating it, the Company addresses it below.

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

[579] Exh. 10, p. 29, l. 11-20 (AmerenUE witness Gary S. Weiss' Direct Testimony).
[580] Exh. 10, p. 30, l. 5-7 (Weiss Direct).
[581] Tr. p. 3628, l. 20-25 (Mr. Weiss).
[582] *Re: General Order 38-A*, 27 Mo. P.S.C. Reports 286, 293 (1945).

> 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, $137,986, 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.[583] 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 one dollar more than $137,986?[584] 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% slice still been serving the Metro East load.[585] Insofar as it is obvious that $22.3 million far exceeds $137,986, 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. Mr. Weiss made those statements under oath.

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[583] Exh. 12, p. 18, l. 12 to p. 19, l. 2 (Weiss Rebuttal).
[584] OPC has stated this number is $137,986, but the difference in the two figures is immaterial.
[585] *Id.*

No one has questioned the veracity of those statements, save perhaps Mr. Kind who complains about a “lack of verification.” The Company and Staff have completely agreed upon the underlying accounting schedules in this case, as evidenced by the Company’s and Staff’s Agreement on the true-up data,[586] (save the five items still in dispute between the Staff and the Company as reflected on the Staff’s Reconciliation – none of which include any Metro East issue). Mr. Kind “reserved his right” to supplement testimony later once he got data request responses relating to the transmission charge issue, which he has now received, and no such testimony has been forthcoming. In short, as Mr. Weiss testified under oath, 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. And given the paltry $137,986 AmerenUE did include in its revenue requirement, as compared to more than $22 million in fuel cost savings, OPC’s proposed adjustment should be denied.

III. Class Cost of Service, Rate Design, and Tariff Issues.

On April 5, 2007, the Commission issued its *Order Approving Partial Stipulation And Agreement Concerning Class Cost Of Service And Certain Rate Design Issues Filed On March 22, 2007*, (“April 5 Order”) which approved the partial stipulation and agreement concerning class cost of service and certain rate design issues filed on March 22, 2007, and ordered the signatory parties to comply with the terms of the partial stipulation and agreement. The approval of the partial stipulation and agreement has resolved the class cost of service and rate design issues, except for the following “unresolved issues”:

1. AmerenUE’s proposal to implement economic development and retention riders (Rider EDR, Rider EDRR);

[586] *See Joint Notification of Agreement on True-Up* filed April 13, 2007.

2. AmerenUE's proposed Industrial Demand Response Pilot (Rider IDR);

3. Missouri Association for Social Welfare's proposal to implement an "essential services" rate;

4. The "SafetyNet" proposal suggested by AARP in its Pre-Hearing Brief that customers be provided credits of $25 per day for electric outages that extend beyond 48 hours. (April 5, Order, p. 2); and

5. Voluntary Green Power issues.

As a result of the approval of the partial stipulation and agreement related to the class cost of service and rate design issues, this Brief will address only the remaining unresolved issues, and will also briefly address energy efficiency and integrated resource planning issues relating to this case.

A. <u>The Commission Should Adopt AmerenUE's Economic Development And Retention Riders</u>.

AmerenUE is proposing two economic development tariffs in this proceeding: the Economic Development and Retention Rider (EDRR) and the Economic Re-development Rider (ERR).[587] Staff also supports the approval of both of these economic development initiatives, and recommends that the Commission approve both of these riders.[588] As Staff witness James Watkins agreed during the hearings, if there is no economic development rider, that's not good for general economic development.[589]

The State of Missouri also indicated that it generally supports the economic development riders, but expressed a concern about the cut-off date contained in the tariff.[590] During cross-examination, Staff witness Watkins indicated that the Staff would not oppose keeping the economic development riders in effect until the next AmerenUE rate case.[591] AmerenUE

[587]Exh. 40, pp. 2-11 (Mill Direct).
[588] Tr. p. 4024, l. 3-9 (Watkins).
[589] Tr. p. 4021, l. 21-25 (Watkins).
[590] Tr. p. 3866, l. 14-25 (Micheel).
[591] Tr. p. 4022, l. 8-11 (Watkins).

believes that the sunset date is an important feature of the ERR and EDRR tariffs, allowing AmerenUE to consider periodic modifications or allowing one or both tariffs to terminate if no longer necessary.

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 terms for the applicable discount to the extent they continue to qualify.

In this proceeding, AmerenUE is proposing to renew the EDR ride with some changes. 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 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, Rider 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.

During the hearings, Public Counsel witness Barbara Meisenheimer indicated that Public Counsel was not opposed to the AmerenUE's economic development riders, provided that AmerenUE shareholders funded the rider discounts.[592] This "funding" issue should not be a concern in this proceeding, however. Any economic development discounts associated with these riders will be funded by AmerenUE shareholders at least until the Company's next rate case. However, it would be appropriate for such discounts to be reflected in future rates, as has been the case in past AmerenUE rate cases, since such discounts produce economic benefits for the entire body of ratepayers.[593]

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

B. <u>The Commission Should Approve AmerenUE's Industrial Demand Response Program</u>.

The Commission should adopt AmerenUE's Industrial Demand Response Pilot (IDR) 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 Company for reliability or

[592] Tr. p. 4038, l. 4-7 (Meisenheimer).
[593] Tr. p. 4024, l. 13-16 (Watkins).

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 provide generous compensation for customers who are enrolled in the program and have the potential to have their service interrupted.[594] 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 the Company plans to conduct a study of its results. AmerenUE is also proposing to limit the availability of Rider IDR to no more than five (5) customers with a total demand response aggregated load of 100 MW.[595] Staff witness Watkins testified that Staff supports AmerenUE undertaking a limited two-year pilot that requires evaluation by November 30, 2009.[596]

MEG witness Billie La Conte raised three concerns with respect to this program. First, she argued that the credit should be larger. Second, she asserted that the proposed limit should be raised from 100 MW to 800 MW. Third, Ms. LaConte contended that the period for the pilot program is too short. However, as AmerenUE witnesses Hanser and Mill explained during the hearings, her concerns are not valid and should be rejected by the Commission.[597]

Mr. Hanser also noted that participation in the previous interruptible tariff at the time it was cancelled only included four (4) customers with approximately 47 megawatts of curtailable load.[598] It is unnecessary to substantially expand this program, as requested by MEG, when there has been only modest participation in such programs in the past. Notwithstanding MEG witness La Conte's desire to expand the proposed IDR program, she testified that she would like

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[594] Tr. p. 4283, l. 16-18; p. 4304, l. 13-7; p. 4305, l. 8-13 (Mill).
[595] Exh. 40, pp. 11-12 (Mill Direct).
[596] Tr. p. 4025, l. 2-11 (Watkins).
[597] Exh. 24, pp. 12-13 (Hanser Rebuttal); Tr. p. 4314, l. 2-18 (Mill).
[598] Exh. 24, p. 13, l. 13-15 (Hanser Rebuttal).

to get the IDR tariff accepted now.[599] Staff suggested that the expansion of the IDR would be an appropriate subject for the collaborative in the Integrated Resource Planning process that is on-going for AmerenUE.[600] Finally, Mr. Mill testified that the Company did not add dollars to its revenue requirement for the IDR pilot program and is not willing to offer up any expansion of the IDR pilot program without getting revenue recognition of doing so.[601] Any increases in the credit amounts paid or in the size of the IDR pilot program should require an adjustment to AmerenUE's revenue requirement to cover the additional costs.

In summary, 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 that 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.[602] 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.[603] It should therefore be approved by the Commission in this proceeding.

C. The Commission Should Not Adopt The Missouri Association for Social Welfare's Proposal To Create An "Essential Service Rate."

In this proceeding, the Missouri Association for Social Welfare (MASW) proposed that the Commission approve an "essential services rate" for residential customers. Under the MASW proposal, the first 600 kWhs of monthly usage would be provided to all residential

[599] Tr. p. 4078, l. 24 (LaConte).
[600] Tr. p. 4035, l. 3-8 (Watkins).
[601] Tr. p. 4286, l. 22-25 (Mill).
[602] Exh. 23, p. 16, l. 15-16 (Hanser Direct).
[603] Exh. 23, p. 16, l. 16-20 (Hanser Direct).

customers at a reduced rate to cover their "essential services".[604] The revenue shortfall from the discounted rate would be recovered from other residential blocks exceeding 600 kWhs of usage.

There are several problems with MASW's proposal. First, MASW witness Robert Quinn relied on unsupported 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 MASW's proposal would reduce retail customers' incentive to invest in energy efficiency (*e.g.*, insulation, more efficient appliances) and would penalize low-income customers with high levels of electricity consumption.[605] Even Mr. Quinn admitted that his proposal is merely a "concept" and not a specific rate proposal.[606] But more importantly, he recognized that middle class and high income customers who do not have any problems paying for their electric bills would receive the discount on their first 600 kWhs of usage under his proposal.[607]

As explained by Staff witness James Watkins, "Staff is opposed to the essential services rate for residential customers because it distorts the price of electricity for all customers while providing only limited assistance to those who need it the most."[608] AmerenUE agrees with Staff on this point, and would recommend that the Commission reject the MASW proposal to create a subsidized "essential services" rate for all residential customers, regardless of their income levels.

[604] Exh. 800, pp. 4-8 (Quinn Direct).
[605] Exh. 24, p. 9, l. 17 to p. 10, l. 17 (Hanser Rebuttal).
[606] Tr. p. 4091, l. 22-24 (Quinn).
[607] Tr. p. 4096. l. 19 to p. 4097, l. 2 (Quinn).
[608] Tr. p. 4025, l. 2-7 (Watkins).

D. The Safety Net Proposal Should be Rejected.

1. The Record is Inadequate to Support the Adoption of the Safety Net Proposal.

The record on the Safety Net proposal, in its entirety, consists of the California tariff sheet for this program at Pacific Gas & Electric Company which was submitted at a local public hearing, and public testimony at local public hearings regarding spoiled food from the extended storm-related outages. This limited record is insufficient basis for the Commission to adopt the proposal.[609]

The program does not distinguish between extended outages that may be the fault of the Company and those that are not. The record is devoid of any evidence why AmerenUE should be penalized for outages that are not under its control. The program does not require that AmerenUE's restoration efforts be found to be insufficient or otherwise lacking. The record does not address why the Commission should ignore issues of fault when considering the proposal. The record contains no evidence as to why $25 a day is the appropriate amount – other than the fact that amount was voluntarily undertaken by one California utility. There is no evidence the situation in California at the time of the undertaking of this tariff is in any way similar to the situation before the Commission in this case. There is no evidence as to why any outage over 48 hours is when the penalty should apply. Would a more appropriate time perhaps be 72 hours or 96 hours or some other time period? This Commission cannot know the answer to any of these questions, because the record is devoid of the necessary information. Consumers Council made no attempt to provide a witness or any competent evidence on any of these issues.

When reviewing the almost non-existent facts about the program that are contained in the record, it becomes clear that there is only one trigger which requires the credit. That sole trigger

[609] As discussed below, in any event there exists no authority to force the Company to file a tariff adopting such a program the costs of which would not, in the Consumer Council's view, be included in the Company's revenue requirement.

is that a customer's service is interrupted for over 48 hours due to "an extended outage."[610] On this point, the record does not contain evidence which relates in any way to the appropriateness of 48 hours as a trigger for the proposed penalty, given AmerenUE's response to the recent storms. For example, Staff's Report filed in Case No. EO-2007-0037[611] found that July 2006 storms "…were extraordinary in terms of their wind speeds and direction and the fact that they occurred only two days apart."[612] The Report continued, "…Staff has not yet found evidence of a more destructive thunderstorm in Missouri in the last 100 years."[613] The record contains no evidence that AmerenUE's restoration efforts were inadequate. Staff found that "When compared to utility responses to 44 major storms between 1989 – 2003, AmerenUE restored more than the average number of customers a day."[614] It continued, "AmerenUE crews restored more than the average number of customers per restoration worker."[615] Finally, Staff's analysis concluded that AmerenUE's restoration efforts were well executed. "Based on these comparative studies and the content of AmerenUE's EERP [Electric Emergency Restoration Plan] versus best practice documents, Staff believes that AmerenUE's response to this outage event was well executed."[616] Rather than having a record which might show a deficiency in the Company's restoration efforts, the record contains evidence that this work was well executed. While the record may show reliability concerns specific to certain areas of the AmerenUE system, the proposal set forth by Consumers Council is designed only to address the presumed impact of extended outages. The record amply demonstrates that the extended outages associated with recent storms were, in large part, beyond the control of the Company and also

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[610] Consumer Council Pre-Hearing Brief, p. 1.
[611] The Commission is entitled to take official notice of this report filed in Case No. EO-2007-0037. Section 536.070(6), RSMo.
[612] Exhibit 243. *Report on AmerenUE's Storm Outage Planning and Restoration Effort Following the Storms on July 19 and 21, 2006, p. 1.*
[613] Id., p. 12.
[614] Id., p. 19.
[615] Id., p. 21.
[616] Id., p. 23.

that AmerenUE's restoration efforts were timely. To implement this proposal would do nothing to improve the restoration efforts of AmerenUE and, consequently, should be rejected by the Commission.

2. AmerenUE would support a program that socializes the cost of this program among all customers.

To be clear, the California Safety Net program was voluntarily undertaken by Pacific Gas & Electric.[617] In this case, the Company has not volunteered to accept the program or its costs.[618] As proposed and despite Consumer Council's use of the word "incentive," the program would function purely as a penalty because the revenue lost due to the required bill credits would not be recovered through rates. AmerenUE believes it is inappropriate (and unlawful) for these funds to be taken from shareholders.[619] AmerenUE witness Gary Rainwater indicated that if the Commission found it to be good public policy to provide these kinds of credits to customers, it would be necessary to socialize the cost of the program among all customers. If that adjustment were made to the proposal, then the Company could support the program.[620]

3. The Commission Does Not Have the Authority to Require That a Tariff Implementing This Program be Filed or Implemented.

The Commission is a creature of statute, and is limited to the powers given it by the Legislature. There is no authority anywhere in the Public Service Commission Law authorizing the Commission to require a public utility to implement a tariff for a program to be funded by shareholders without the Company's consent. Unless the Commission includes the full cost of this program in the Company's cost of service, it would be setting rates without including all costs in the Company's revenue requirement. The Commission cannot establish an obligation and then order that obligation to be funded solely out of shareholder funds.

[617] Consumer Council Pre-Hearing Brief, p. 2.
[618] Tr. p. 1975 to p. 1976, 1983 (Rainwater).
[619] Tr. 1975 (Rainwater).
[620] Tr. p. 1975 to p. 1976, 1083 (Rainwater).

If an aggrieved AmerenUE customer filed a complaint with the Commission and asked for $25 for each day he or she was without power as compensation for spoiled food, the Commission would be without authority to award that claim. The Commission exercises quasi judicial powers that are "incidental and necessary to the proper discharge" of its duties. However, its adjudicative authority is not plenary.[621] The Commission authority extends only to the ascertainment of facts and application of the existing law to those facts in order to resolve issues before it.[622] As such, the courts have held that the Commission is without authority to award money damages.[623]

Consumer Council's proposal asks the Commission to disregard the long held limits on its authority and to order a tariff which awards money or bill credits as damages any time there is an extended electric outage, regardless of the cause of the outage, and it asks the Commission to do so without building a record upon which the Commission can even consider the proposal. The Commission should reject the Safety Net proposal.

E. The Commission Should Approve AmerenUE's Voluntary Green Program Tariff.

AmerenUE has proposed a Voluntary Green Program (VGP) tariff as a method of providing its customers with the option of purchasing Renewable Energy Certifications (RECs) to support the development of renewable energy. AmerenUE believes it has customers who want to financially support the development of renewable energy and is asking the Commission to approve the proposed VGP tariff as a way to allow those customers a means of immediate participation in the development of renewable energy.[624]

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[621] *State Tax Commission v. Administrative Hearing Commission*, 641 S.W.2d 69, 75 (Mo. 1982), quoting *Liechty v. Kansas City Bridge Co.*, 162 S.W.2d 275, 279 (Mo. 1942).
[622] *State Tax Commission, supra.*
[623] *American Petroleum Exchange v. Public Service Commission*, 172 S.W.2d 952, 955 (Mo. 1943).

[624] Exh. 40., p. 13, l. 19 (Mill Direct).

1. Objections raised during these proceedings are not a reason to reject the tariff.

During the course of these proceedings, objections were raised in two areas. First, it was suggested that customers could become confused by the program and think they were purchasing actual, renewable energy.[625] Second, Staff was concerned that the implementation of this tariff would divert AmerenUE from developing actual renewable assets.[626] AmerenUE does not believe either concern should prevent the Commission from providing this option to the Company's customers who chose to participate.

The VGP program does not involve the actual delivery of renewable energy 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 monthly usage. This money is used to purchase and retire RECs.[627] One REC is equivalent to 1,000 kWh of renewable energy.[628] 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. [629]

In response to the concerns noted above, AmerenUE considered these issues when designing the program prior to its submission to the Commission. AmerenUE is very concerned about customer confusion and so the program provides a multitude of safeguards for the Company's customers. First, this program is completely optional for the Company's customers. All customers who elect to participate under the tariff are provided additional detailed, written information about how the program works. If participating customers decide to end their

[625] Tr. p. 1765-66 (Mill).
[626] Exh. 221, p. 1, l. 25-29 (Staff witness Mantle Rebuttal).
[627] Exh. 43, p. 2, l. 22-23; p. 3, l. 1-6 (Barbieri Surrebuttal).
[628] Exh. 43, p. 16, l. 10-14 (Barbieri Surrebuttal).
[629] Exh. 43, p. 3, l. 22 to p. 4, l. 2 (Barbieri Surrebuttal).

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.[630] Further, 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.[631] 3 Phases is very active with these types of programs and won the U.S. EPA Green Energy Provider of the Year award in 2005.[632] Finally, the program will be certified by Green-e, also a nationally recognized organization in this area. Green-e will provide verification and the audit process for this program.[633] These multiple safeguards are designed to protect AmerenUE customers who decide to participate.

Staff's concern, that AmerenUE should develop actual renewable resources, is also not a reason to reject this program. Staff's position is based on the false dichotomy that there is a trade off between offering RECs and building or procuring actual renewable power. Indeed, events at AmerenUE prove the specious nature of the argument. Currently, the Company is in the process of developing at least 100 MW of wind generation. A Request for Proposal (RFP) has been issued and responses to that RFP are currently being evaluated.[634]

2. AmerenUE's customers have indicated their support for the VGP tariff.

AmerenUE has received many letters of support for the VGP program, including from the following organizations: Center for Resource Solutions, American Wind Energy Association (AWEA), U.S. Green Building Council, Washington University-St. Louis, Wind Capital Group, Energy Matters and the Heartland Renewable Energy Society. In addition, AmerenUE has also

[630] Exh. 43, p. 6, l. 15 to p. 7, l. 7 (Barbieri Surrebuttal).
[631] Exh. 40, p. 13, l. 8-10 (Mill Direct).
[632] Tr. p. 1733, l. 1-2 (Barbieri)
[633] Exh. 40, p. 13, l. 11-18 (Mill Direct); and Exh. 43, p. 6, l. 18-21 (Barbieri Surrebuttal).
[634] Tr. p. 1733, l. 13-15 (Barbieri).

received over a dozen letters (individually or grouped) from customers who support the VGP tariff.[635]

Finally, AmerenUE would note that, unlike the process and time required for the development of a wind farm, once the Commission approves this tariff, it can be almost immediately implemented. With the work that AmerenUE has already completed, there is very little lead time required before customers of AmerenUE can begin their voluntary participation in the program.[636] AmerenUE believes the Commission should approve the VGP tariff to allow interested customers an avenue to support the development of renewable resources.

F. <u>Energy Efficiency/Wind Power Issues.</u>

1. The Commission should support AmerenUE's progress towards its 2008 Integrated Resource Plan (IRP) filing.

As the Commission is aware, AmerenUE is required to make its next Integrated Resource Plan filing in February of 2008. In this case, however, many parties have requested the Commission to order AmerenUE to commit to a particular program or type of program or even a particular type of tariff. In many of these cases, AmerenUE believes the most appropriate driver is its 2008 IRP filing and asks that the Commission allow the IRP process to work. It is through that process that a determination of what programs are and are not to be ultimately funded should be made.[637]

2. Energy Efficiency Program Funding.

The Missouri Department of Natural Resource's (DNR) specific request is that the Commission specify in its rate case order a minimum amount of money be spent on energy efficiency programs (not to include demand management programs). Specifically, DNR

[635] Exh. 43, p. 8, l. 2-8 (Barbieri Surrebuttal).
[636] Exh. 43, p. 3, l. 5-6 (Barbieri Surrebuttal).
[637] Tr. p. 1758, l. 1-16 (Moehn).

recommends $10 million for year one and escalates that amount to $20 million a year.[638] Staff does not support placing a specific number on these programs but rather believes the Commission should allow the IRP process dictate the appropriate level of spending.[639]

AmerenUE agrees with Staff's concern, but also believes it is possible to set a minimum spending level that is rational and serves as a good faith commitment on the part of AmerenUE. If done in this manner, a reasonable minimum DSM spending goal will not undermine the integrity of the resource planning process.[640] AmerenUE has committed to providing a minimum amount of funding, specifically $13 million per year.[641] The Company's commitment includes both demand management programs as well as energy efficiency. Again, this dollar amount is to provide the Commission with a measure of assurance that AmerenUE is willing to commit the appropriate level of resources to the results of its IRP process.

3. Development of Wind Powered Generation.

AmerenUE has committed to including at least 100 MW of wind in its generation portfolio. Testimony submitted by DNR voiced support for increasing wind generation in the Company's generation portfolio.[642] AmerenUE does not disagree with the points set forth in DNR's testimony. However, again, the Company feels the appropriate driver is its IRP process.

AmerenUE has acted on its commitment to install 100 MW of wind power. On January 31, 2007, an RFP for a minimum of 100 MW of wind generation was issued on behalf of AmerenUE.[643] Responses to that RFP have been received and are now in the evaluation process as part of the previously described IRP process.[644] The 100 MW should be seen as the first step

[638] Exh. 650, p. 8, l. 6-9 (MDNR witness Wilbers Direct).
[639] Exh. 221, p. 3, l. 6-23 (Staff witness Mantle Rebuttal).
[640] Exh. 37, p. 27, l. 16-19 (Moehn Surrebuttal).
[641] Exh. 37 p. 28, l. 19 (Moehn Surrebuttal).
[642] Exh. 652, p. 1, l. 22 to p. 2, l. 2 (Anderson Direct).
[643] Exh. 43, p. 4, l. 7-8 (Barbieri Surrebuttal).
[644] Tr. p. 1739, l. 15 (Barbieri).

in a process which will evaluate the appropriateness of increasing that commitment to a larger amount of the Company's power generation portfolio.[645] But again, the driver should be the results of the IRP planning process, which is currently underway, and not merely the desire of DNR for an immediate commitment for a larger amount of wind power. Indeed, like all resource decisions, it is the Company, not the Commission that has the responsibility to decide upon which resources to acquire, and when. Consequently, the Commission is not authorized to order a particular level of wind power in the Company's portfolio although, as noted above, the Company is committed to pursuing at least 100 MW of wind power. For these reasons, no Commission action with respect to wind power initiatives at AmerenUE is warranted.

Conclusion

It is critical to the Company's ability to provide safe, adequate and reliable electric service that its rates reflect its true cost-of-service, including a reasonable opportunity to earn a fair return on equity. Consequently, it is necessary that the remaining disputed issues, addressed above, be resolved in the Company's favor. As indicated by the Staff's Reconciliation, this would result in an overall rate increase of approximately $245 million, or approximately 12% above current rates. Even had the Company's entire rate increase request been granted, the Company's average rates would still have been the lowest in the State, and would have been low relative to regional and national averages. That is even more true now that the Company's request has been reduced by more than $100 million from the rate increase request originally made when the case was filed.[646]

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[645] Tr. p. 1737, l. 2-7 (Barbieri).

[646] And similarly, for example, the Staff's Preliminary Reconciliation Provided to all of the parties in late December reflected Staff's view at that time that a revenue requirement reduction of $157 million was warranted, but according to Staff's latest reconciliation, Staff's proposed reduction has dropped by approximately $95 million.

For the reasons discussed herein, the Company respectfully requests that the Commission approve the Company's FAC request, and authorize it to file revised tariff sheets reflecting an overall increase in rates of $245.4 million.

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing Post-Hearing Brief of Union Electric Company d/b/a AmerenUE was served via e-mail, to the following parties on the 20th day of April, 2007.

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AMERENUE
ER-2007-0002
REVISED TRUE-UP RECONCILIATION

4/19/2007

	Staff	State	OPC	MIEC	Commercial Group
Company Revenue Requirement [1]	$ 245,411,545	$ 245,411,545	$ 245,411,545		
Pinckneyville and Kinmundy [2]		(10,806,000)	(16,306,479)		
Peno Creek [2]			(3,825,998)		
Return and Capital Structure:					
A. Capital Structure [2]			(19,443,025)		
B. ROE [2]	(129,106,126)	(140,761,540)	(104,309,525)	(102,291,817)	
Metro East			(137,986)		
EEInc.	(65,296,469)	(73,137,000)	(75,016,469) [9]		(62,599,866)
Off-system Sales [8]	(27,496,178)	(72,336,242)	(72,336,242)	(5,427,815) [4]	
Taum Sauk Hold Harmless - Capacity Sales			(10,320,000) [10]		
SO_2		(20,335,000)	(23,601,841)		
Depreciation:					
A. 240-10.020		[3]			
B. Life Span	(57,701,438)		(57,701,438)		
C. Nuclear Life Extension	(27,919,066)	[3]	(27,919,066)	(46,570,693)	
D. Production Non-Nuclear Terminal Salvage [11]				(30,208,314)	
E. Historic Inflation Rate			(20,060,630) [5]	(28,322,898) [6]	
F. No Inflation Rate				(15,338,285) [7]	
Revenue Requirement [1]	$ (62,107,732)	$ (71,964,237)	$ (185,567,154)		

(1) Reflects true-up results
(2) Value depends on ROE, Capital Structure and/or Rate Base
(3) State testimony, but not quantified
(4) Based on wholesale prices only, no change in volumes
(5) Historic inflation rate versus 2.5% future inflation rate
(6) Reduce inflation rate
(7) Eliminate inflation rate
(8) Reflects the Company's new off-system sales margin of $202,500,000
(9) Reflects $2/kW/Month on 405,000 kW for capacity sales revenue, in addition to Staff's valuation
(10) Reflects $2/kW/Month on 430,000 kW for capacity sales revenue
(11) According to the Nonunanimous Stipulation and Agreement Regarding Certain Depreciation Issues, Paragraph 3.a, filed 3/19/2007, AmerenUE is no longer pursuing production non-nuclear terminal net salvage. The stipulation was opposed by MIEC and OPC.

Appendix 1