Exhibit No.:	001NP
Issue:	Overview of Company and Rate Increase Request; Operations/Reliability Improvements; Risks/Challenges Facing the Company; Witness List
Witness:	Thomas R. Voss
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
Case No.:	ER-2008-0318
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2008-0318

DIRECT TESTIMONY

OF

THOMAS R. VOSS

ON BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

** **DENOTES HIGHLY CONFIDENTIAL INFORMATION** **

St. Louis, Missouri
April, 2008

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DIRECT TESTIMONY

OF

THOMAS R. VOSS

CASE NO. ER-2008-____

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas R. Voss. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed?

A. I am employed by Union Electric Company d/b/a AmerenUE ("Company" or "AmerenUE") as President and Chief Executive Officer. I have held that position since January 1, 2007.

Q. Please summarize your educational background, professional affiliations and work experience.

A. My educational background, professional affiliations and work experience are summarized in Schedule TRV-E1, which is attached to this testimony.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (a) provide an overview of the Company and of its rate increase request; (b) explain how the Company has taken steps to improve its operations since its last rate case in 2006 in response to concerns expressed by our customers and the Commission over the reliability of our service; (c) address some of the risks and challenges AmerenUE faces now and will face in the future, particularly given the current state of the electric utility industry; and (d) provide a listing of AmerenUE's witnesses who are filing direct testimony in this case together with a brief description of the topics upon which they are testifying

III. OVERVIEW OF COMPANY/REQUESTED RATE INCREASE

Q. Mr. Voss, please provide an overview of the Company's operations.

A. AmerenUE is an integrated electric utility operating across a wide and diverse service territory, primarily in the eastern half of Missouri, but also in northern Missouri and in limited areas of northwestern Missouri.[1] Its service territory includes several Missouri cities, including the City of St. Louis and the Greater St. Louis Area. AmerenUE owns and operates four large baseload coal-fired generating plants with a combined generating capacity of approximately 5,400 megawatts ("MW"). Those plants are the Labadie Plant, the Rush Island Plant, the Sioux Plant, and the Meramec Plant, all of which are located in eastern Missouri in or near St. Louis County. The Company also owns and operates one of the most efficient nuclear plants in the United States, the Callaway Nuclear Plant, located near Fulton, Missouri. The Callaway Plant has a generating capacity of approximately 1,200 MW. The Company also owns and operates 50 combustion turbine generator ("CTG") units, most of which are fired by natural gas, and which are located at 15 different plant sites, mostly in Missouri and some in Illinois. The combined generating capacity of these CTG units is approximately 3,000 MW. Finally, the Company operates the Keokuk and Taum Sauk hydroelectric plants, which have a combined generating capacity of approximately 810 MW.

AmerenUE has approximately 1.2 million retail electric customers in Missouri, more than 1 million of which are residential customers. These customers are

[1] AmerenUE also operates smaller natural gas utility in Missouri.

located in 349 communities in 57 of Missouri's counties. AmerenUE's service territory is large (approximately 24,000 square miles) and diverse, ranging from the large urban areas in and around St. Louis to mid-sized communities such as Cape Girardeau and Jefferson City to small towns like Irondale and Pilot Grove. The Company's service territory traverses open fields, pastures, large rivers, streams, large lakes (including the Lake of the Ozarks), and heavily wooded areas, including large portions of the Mark Twain National Forest, which is located throughout Missouri.

In addition to operating and maintaining the approximately 10,400 MW of generating capacity needed to serve these customers, the Company operates and maintains approximately 32,000 line miles of distribution lines, approximately 630 distribution substations, and approximately 2,900 miles of transmission lines, all of which are necessary to serve its many customers located across its wide and diverse service territory.

AmerenUE also is one of the largest employers in Missouri, with approximately 3,300 employees. In addition, AmerenUE is funding pension benefits for approximately 4,700 retired employees and their families.

Q. How much of a rate increase is AmerenUE requesting?

A. AmerenUE is requesting an overall increase in its Missouri retail rates of $250.8 million, an approximately 12.1% increase.

Q. Why does AmerenUE need an increase in its retail rates at this time?

A. Simply stated, the costs required to generate, transmit and ultimately deliver electricity to our customers have risen sharply and continue to rise. Among those costs which are rising sharply is the cost of the fuel the Company must burn (principally coal, nuclear fuel, and natural gas) to produce the electricity our customers consume. The

Company is also incurring substantially higher infrastructure costs, including the costs associated with our efforts to improve reliability of service. This effort, embodied in part in Project Power On discussed in more detail in the direct testimony of AmerenUE witness Richard J. Mark, is in response to the concerns we have heard from our customers and from the Commission itself. Among the Project Power On costs being incurred are substantial investments in undergrounding distribution circuits across our system, the cost of aggressive vegetation management practices in compliance with the Commission's new vegetation management rules, and the cost of systematic inspections of our electric system, in accordance with the Commission's new infrastructure inspection rules.

In 2006 and 2007, AmerenUE invested approximately $825 million in generation, transmission, and environmental infrastructure, and another approximately $283 million into our distribution system. Significantly higher capital investments including approximately $1 billion in 2008 will be needed for generation, environmental and distribution infrastructure going forward, as shown in Schedule TRV-E2-2. But these capital investments are not the only source of cost increases. Other costs also continue to rise, such as wages, employee benefits, medical costs, general maintenance costs (including the cost of basic materials we must buy to deliver reliable service, such as copper wire, poles, steel crossarms, and a myriad of other essential items).

Q. Is AmerenUE alone in facing these cost pressures and challenges?

A. No. The cost pressures and related challenges faced by AmerenUE are being experienced throughout the utility industry in the U.S. and world-wide, as addressed in the direct testimony of AmerenUE witness Dr. Kenneth Gordon.. The *Public Utilities Fortnightly* article attached as Schedule TRV-E3 is an example of a number of recent studies documenting the rapid cost increases facing the utility industry. The broader challenges faced by AmerenUE and the remainder of the industry were also summarized in a recent presentation presented to the Commission and Missouri legislators by Michael Oldak, the Director of Regulatory Policy for the Edison Electric Institute.

Q. AmerenUE is requesting a fuel adjustment clause in this case. Doesn't that at least address rising fuel costs?

A. A fuel adjustment clause ("FAC") will, prospectively, address rising fuel costs. However, just since the implementation of our last rate increase order, the Company's net fuel costs have risen by approximately $27.5 million, as noted in the direct testimony of AmerenUE witness Gary S. Weiss. Those cost increases are already in place, and coupled with other significant cost increases, have prevented the Company from earning the return the Commission just authorized in May 2007. Indeed, as Mr. Weiss' direct testimony discusses, while the Commission authorized a return on equity of 10.2% in the Company's last rate case, for the nine months of June 2007 through February 2008, the Company's earned return on equity has consistently been well below its authorized return on equity, as shown in the table below, which was taken from Mr. Weiss' testimony.

Month	Mo. Electric Rate Base	Mo. Electric Operating Income	Return on Rate Base	Return on Equity
June	$5,894,787,447	$ 409,836,625	6.95%	8.24%
July	5,857,606,784	413,787,801	7.06%	8.46%
August	5,852,708,753	434,074,853	7.42%	9.15%
September	5,832,533,516	454,226,385	7.79%	9.88%
October	5,843,612,754	438,158,731	7.50%	9.31%
November	5,850,240,664	429,010,087	7.33%	8.99%
December	5,815,927,377	433,537,872	7.45%	9.22%
January	5,814,605,545	440,938,071	7.58%	9.48%
February	5,856,834,745	433,006,825	7.39%	9.10%
Average				9.09%

As can be seen from the table, during that period the Company's average earned return on equity was just 9.09 percent, or 111 basis points below that authorized by the Commission.

As our costs continue to rise, the pattern of under-earnings will only get worse. Indeed, a 9.09 percent return on equity is nearly 200 basis points below the Company's current cost of equity, as discussed in the direct testimony of AmerenUE witness Professor Roger A. Morin. Additional fuel cost increases will occur later in 2008 and the Company will face yet another substantial fuel cost increase effective January 1, 2009, months before rates in this case will likely take effect, which will further erode AmerenUE's returns. These fuel cost increases are discussed in more detail in the direct testimonies of AmerenUE witnesses Robert K. Neff, Scott A. Glaeser, and Randall J. Irwin. A base rate increase is therefore essential at this time just to permit the Company to recover its current fuel costs, and an FAC is essential to address continuing uncertainty and volatility in fuel costs, as well as continuing increases in fuel costs which are expected in coming years, as addressed in more detail in the direct testimony of Company witness Martin J. Lyons, Jr.

IV. STEPS TO IMPROVE THE COMPANY'S OPERATIONS

Q. You noted that the Company has taken steps and has spent substantial dollars to improve its operations, and that this was at least in part in response to customer and Commission reliability-related concerns. What caused the expression of these reliability-related concerns?

A. As I am sure the Commission recalls, the Company experienced a series of extremely severe storms during the pendency of its 2006 rate case, including one immediately after the case was filed. On July 19, 2006 a devastating and highly unusual thunderstorm, with wind speeds between 70 and 80 m.p.h. and with winds coming at times from the opposite direction normally experienced — the east — swept through AmerenUE's service territory leaving over 646,000 AmerenUE customers without service. A second severe thunderstorm hit the same area on July 21, 2006. Although numerous AmerenUE linemen and crews from other utilities mobilized immediately and acted swiftly in restoring service (AmerenUE's restoration effort was described as "well-executed" in the Staff's investigation report), it took nine days to restore service to all of the Company's customers. Customers who were out of service suffered from lack of air conditioning during a particularly hot period, their refrigerated food spoiled, businesses had to close for the duration of the outage, and customers experienced numerous other hardships and inconveniences, disruptions to their lives, and economic losses.

Four months later, on November 30 and December 1, 2006 — just a few weeks before the Commission held a series of local public hearings in the rate case — the worst ice storm AmerenUE has experienced in the last 30 years left 290,000 customers without power, this time during unusually cold weather. Although, again, AmerenUE linemen and crews called in from other states did a superb job of restoring service under adverse working conditions, some customers were out of service for as long as eight days, again, resulting in significant hardship and inconvenience, disruption, and economic loss.

Finally, on January 13, 2007 — in the midst of the series of local public hearings being held in the last rate case — a second ice storm occurred in which 270,000 AmerenUE customers lost power. This time it took AmerenUE only five days to restore power to all customers — a substantially shorter restoration time than other Missouri electric utilities and cooperatives that were impacted by the same storm. Nonetheless, customers were again significantly and negatively impacted by this disruption of service.

Q. How did customers react to this series of events?

A. Many customers, especially those that experienced outages from more than one of the storms, were understandably quite frustrated by the disruptions to their service. They expressed their frustration in a variety of ways. Some customers called or wrote AmerenUE to complain. Others contacted the Commission, the Office of the Public Counsel or the media. Still others attended the series of local public hearings the Commission held across AmerenUE's service territory both in connection with the Staff's investigation of the July, 2006 storm and the 2006 rate case.

In general, the customers who expressed complaints blamed AmerenUE for the problems they were experiencing. They criticized AmerenUE for a number of things, claiming that the Company should have more aggressively trimmed trees to minimize storm outages and that the Company should have more adequately maintained or replaced facilities. Despite generally high marks from the Staff for its storm response and restoration efforts (and an EEI award for its storm response for the November/December 2006 and January 2007 ice storms), some customers also claimed that AmerenUE should have more promptly restored service following the storm outages. In addition, some customers also testified about repetitive outages at their homes that they alleged had nothing to do with the storms.

Q. How did the Commission react to these complaints?

A. The Commission, understandably, asked a great many questions about the Company's tree trimming and infrastructure maintenance and replacement efforts both during the local public hearings and during the evidentiary hearings for the rate case. In addition, on December 6, 2006 Warren Wood, then the Director of the Commission's Utility Operations Division, sent a letter to AmerenUE on behalf of the Commission, requesting that the Company propose "all possible approaches" to address the continuing problem of customer outages. The letter requested a response from AmerenUE by January 4, 2007. A copy of this letter is attached as Schedule TRV-E4. The Commission also proceeded with and completed two electric utility rulemakings involving vegetation management and infrastructure inspection, as noted above, and is currently engaged in a third rulemaking regarding reliability reporting. These rulemaking proceedings have made it clear that the Commission expects all of the utilities under its jurisdiction, including AmerenUE, to take reasonable and prudent steps to improve operations and reliability.

Q. How did AmerenUE respond to these customer complaints and the concerns expressed by the Commission?

A. To begin with, I responded to the Commission's December 6, 2006 letter with a set of twelve possible approaches to address reliability issues, from improvements in the Company's vegetation management practices to infrastructure improvements and tariff modifications. A copy of this correspondence is attached as Schedule TRV-E5. In addition we took a number of steps to gain a better understanding of the concerns our customers raised. AmerenUE personnel, including senior executives, read the transcript of the local public hearings held in the rate case and storm investigation proceeding, and the Company followed up on the complaint of every witness who testified about a specific service problem. In addition, the Company listened to customer concerns expressed during literally hundreds of meetings with local officials and organizations, such as mayors, city council officials and neighborhood groups. We also conducted interviews in a series of customer focus groups to help us better understand what our customers wanted. These steps are explained in more detail in Mr. Mark's direct testimony.

Q. What did AmerenUE learn from listening to its customers?

A. We learned that the most important expectation our customers have for us is that we deliver reliable service for them. While reliable electric service has always been important, customer expectations are much different today than they were in even the recent past. AmerenUE had previously concentrated its focus on being a low cost provider of electric service. In this, we were very successful and in recent years we have consistently had among the lowest electric rates in the country. However, because of changing customer needs, our customers have made clear to us that having reliable service is even more important than having the lowest rates possible. Customers now rely on electricity more than they have in the past and digital technology makes more customer appliances vulnerable to even momentary outages.

Moreover, weather patterns in our service territory appear to have changed, making severe storms a more frequent and substantial part of our business. Since our 2006 rate case ended in early 2007, we have experienced two additional severe storms, which resulted in outages for hundreds of thousands of customers. The increasing frequency and severity of these storms has revealed a need to invest in more tree trimming and to underground or otherwise "storm harden" our system, where practical and cost-effective, to reduce storm-related outages.

Q. What steps has the Company taken to directly address reliability issues?

A. As explained in Mr. Mark's testimony, after receiving input from and listening to customers, the Company took several steps to improve the reliability of its system. First, we hired a consultant, KEMA, to conduct an exhaustive review of our electric transmission and distribution systems, and recommend improvements to storm harden the systems. KEMA is an internationally known firm with a long history of helping utilities improve their operations. Many of KEMA's recommendations are being implemented by the Company today, and others are under consideration for future implementation. Second, the Company actively participated in the Commission's rulemaking proceedings involving vegetation management, infrastructure and reliability. We believe that the vegetation management and infrastructure rules that the Commission recently adopted will result in long-term, sustainable improvements in reliability and the Company has adopted the standards contained in those rules as of January 1, 2008. In addition, we believe that the reliability rules, still under consideration, will provide the Commission with uniform measures of reliability that will permit close tracking of the progress Missouri electric utilities are making in improving reliability. Finally, AmerenUE has committed to investing approximately $500 million into our distribution system over a three-year period to improve reliability, as discussed in more detail in Mr. Mark's testimony.

Q. Do you anticipate that the steps the Company is taking will improve reliability and customer satisfaction?

A. Absolutely. The enhancements to our vegetation management and infrastructure inspection programs are already paying dividends. The reliability of particular "worst performing" circuits where work has been done has already measurably improved. Undergrounding of circuits with repetitive reliability problems, which is an important component of Project Power On, will immediately and significantly improve service for customers served on those particular circuits. More importantly, though, the steps we are taking now should result in material improvement in the reliability of the whole system over the long term. Our customer satisfaction metrics are improving, and I believe this is a direct result of the improvements we have made and continue to make in reliability.

Q. Does this mean that the Company and its customers will never face large-scale outages again?

A. No. If the Company experiences severe storms such as those that occurred during the 2006 rate case, widespread outages will still be unavoidable. However, the programs we are undertaking now will result in steady, sustainable improvement of day-to-day reliability in the long run.

Q. How does this discussion of AmerenUE's reliability programs pertain to this rate case?

A. Reliability and customer satisfaction are two important areas the Commission almost always considers whenever any utility seeks a rate increase. In addition, in this case a portion of the cost increases the Company has experienced stems directly from the steps that we have taken to improve reliability. For example, the increases in rate base and certain operations and maintenance costs reflected in our cost of service study are largely related to the programs we have undertaken to improve reliability.

V. CHALLENGES AND RISKS FACING THE COMPANY

Q. You mentioned that increases in the costs the Company must incur to improve service reliability necessitated this rate case filing at least in part. Are there other major factors that are driving the need for AmerenUE to seek a rate increase?

A. Yes. As I noted earlier, the costs AmerenUE and other electric utilities are facing to provide service to customers have been increasing dramatically—far faster than the overall level of inflation. For example, fuel costs have increased, and are continuing to increase significantly. AmerenUE's delivered coal costs increased since the last rate case and, as Mr. Neff shows, are expected to increase by 7% and 16% in 2009 and 2010, respectively. These increases are both for the cost of the coal commodity itself, and for coal transportation, which often include price escalators and diesel fuel surcharges which could contribute to even higher costs. The cost of natural gas and nuclear fuel are also increasing rapidly, driven by sharply increasing demand in the global markets.

Components of AmerenUE's transmission and distribution system also have increased in price. For example, since 2004 the cost of pole transformers has increased approximately 70 percent, wooden utility poles are up about 40 percent, underground aluminum wire is up about 30 percent and copper wire is up about 100 percent. Add to that normal inflation that applies to almost every other cost AmerenUE is paying, and it is easy to see why rates must increase. Dr. Gordon, provides a perspective on how these cost increases are impacting the entire electric utility industry in his direct testimony. Mr. Weiss reflects the specific impact of these cost increases on AmerenUE in the cost of service study he has prepared for this case.

Q. Do the normal rate case procedures available in Missouri provide a sufficient mechanism for AmerenUE to recover the increasing level of costs that it is facing and still earn a fair return on equity?

A. Unfortunately, no. In an environment where costs are increasing rapidly, the ability of utilities to earn a fair return is severely compromised by "regulatory lag," which is more pronounced in Missouri than in many other states. Regulatory lag is the delay in the time between when the increasing costs are incurred and the effective date for the new rates resulting from a rate increase request. A rate case in Missouri typically takes approximately

11 months to complete. AmerenUE's costs have been increasing rapidly since the conclusion of its last rate case (new rates took effect in June, 2007), and as noted earlier, significant fuel cost increases took effect on January 1, 2008. Consequently, AmerenUE will experience a significant lag — perhaps as much as 15-18 months — between the time when material increases in costs prevented it from earning its authorized return on equity and the time it can actually begin to reflect those higher costs in its rates. This earnings shortfall exists even though AmerenUE has filed this rate case only approximately 10 months after its last rate increase became effective.

For several reasons, regulatory lag for Missouri utilities is more pronounced than that for utilities in many other states. First, Missouri uses an historic (rather than projected) test year, meaning that rates designed to cover costs in the future are set based upon data from the past, which often reflects a cost level that is less than that which will be experienced in the future when the rates are actually in effect. Second, Missouri statutes prohibit electric utilities from recovering costs due to construction work in progress ("CWIP") on plant until the plant is placed in service. Missouri also, with rare exceptions, does not allow temporary or interim rates that would be subject to refund pending final resolution of rate increase requests which, as noted above, results in many months of delay in implementing necessary rate increases. Finally, unlike almost every other integrated utility in the country, AmerenUE has not been able to utilize an FAC to recover legitimate changes in its net fuel costs. The impact of regulatory lag on AmerenUE's earnings in the absence of an FAC is addressed in the direct testimony of Mr. Lyons, who also explains our proposed FAC in detail.

Q. You noted the Company's inability to earn its authorized return. Please elaborate.

A. In the Company's last rate case, concluded in May 2007, rates were set based upon a test year ending June 30, 2006, with a true-up of several items through January 1, 2007. Increasing costs from January 1, 2007 through the end of the test year utilized to determine the Company's cost of service for this filing (through March 31, 2008, with certain pro forma updates for known and measurable items through June 30, 2008 as discussed in Mr. Weiss' direct testimony), show that the Company is already under-earning by approximately $251 million per year — less than a year after the implementation of our last $43 million rate increase.

Q. Why should the Commission be concerned with regulatory lag? Isn't that just a problem for the utilities?

A. The Commission should be concerned about regulatory lag because it can undermine the financial strength of a utility, particularly where delays in the recovery of significantly increasing costs occur over a long period of time. Utilities that are impacted by regulatory lag must pay more for capital, and in some cases their ability to access capital at any price can be significantly impaired. Access to capital at reasonable prices has become critically important in just the last few months as the impact of the sub-prime mortgage crisis is affecting the capital markets. In short, businesses that lack financial strength and that need large sums of capital, like utilities, face higher capital costs and thus their ratepayers face higher rates. Dr. Gordon discusses the problems that regulatory lag can create in some detail in his direct testimony.

This is not a hypothetical issue for AmerenUE. In 2008 and 2009, as shown in Schedule TRV-E2-2, AmerenUE expects to make capital expenditures of approximately $1.8 billion, which is an investment equal to almost one-third of AmerenUE's entire existing rate base. AmerenUE's capital needs are substantial even apart from the need, in the not-so-distant future, to build a new baseload generating plant. The point is that in both the near term and the long run, AmerenUE needs to timely recover its costs and earn a fair return on its shareholders' investment so that it can maintain the financial strength needed to support infrastructure investment needs and the long-term benefits that these investments create for our customers.

Q. What can the Commission do to mitigate regulatory lag in this case?

A. Although the Commission is bound to follow the statutory prohibition against including CWIP in rate base and AmerenUE is not requesting that the Commission depart from its reliance on an historic test year to set rates, there are a number of steps that the Commission can and should take in this case to mitigate the adverse impact of regulatory lag on AmerenUE in this increasing cost environment.

First, AmerenUE will be requesting a true-up of certain cost and revenue items to September 30, 2008. This true-up is generally consistent with that permitted in AmerenUE's last rate case, and it will permit AmerenUE's rates to reflect the most recent costs possible, given the scheduling constraints inherent in rate case proceedings. As I noted, because reliance on historic costs is designed to arrive at a cost of service that will apply in the future (in this case, from March 2009 forward), the Commission should set rates using the most current data possible. Second, the Commission should include in the cost of service all of the known and measurable costs that will be incurred at the time rates established in this case will take effect. That would include, for example, the full annual cost of complying with the Commission's new vegetation management and infrastructure rules, and the cost of nuclear fuel which has already been purchased and which will be loaded into the Callaway nuclear plant before this rate case is concluded (by November of this year). Finally, and importantly, the Commission should also approve the FAC AmerenUE has proposed.

Q. Given the knowledge that regulatory lag would continue to prevent the Company from earning its authorized return for an extended period of time, why is the Company making the investments you discuss above?

A. First of all, there are many day-to-day costs in the Company's business which are increasing regardless of the additional investments the Company is making. I discussed those earlier, and as noted, they are also addressed from an industry-wide perspective in Dr. Gordon's testimony. Moreover, the Company has heard the Commission's and its customers' concerns, and is committed to making capital investments in its system to improve its operations and reliability, as I discussed earlier. The Company is counting on a fair and constructive regulatory environment in Missouri to allow it to charge rates necessary to make those improvements, and to meet the substantial challenges facing the Company in the not-so-very-distant future.

Q. What are some of those challenges?

A. Aside from the rapidly increasing costs, other challenges are on the horizon. It appears a near certainty that significant carbon legislation will soon become a reality. As discussed in Ameren Corporation's 2007 Environmental Report (titled *Stewardship*), even under the most flexible carbon proposals, wholesale electricity prices would be expected to increase 60% by 2030. Given that more than 76% of AmerenUE's energy is generated from coal-fired plants, carbon legislation will almost certainly create great challenges for AmerenUE and its customers.

Carbon is not the only environmental issue facing the utility industry in general, and the Company in particular. Substantially more stringent controls on SO_2 and mercury were adopted in 2005, which are necessitating a new scrubber at the Sioux Plant to be completed near the end of 2009, and which are otherwise requiring the Company to utilize its substantial emissions allowance bank to defer other major capital costs which will be necessitated in the future. With respect to mercury controls, a recent federal court decision has sent the 2005 mercury rules back to the EPA, which could ultimately mean even more stringent controls than those envisioned in the 2005 rules, resulting in even higher costs.

As I also noted earlier, the Company will need a new baseload generating unit within the next 10 to 12 years, and is preserving its option to build a second nuclear unit at the Callaway Plant. Such endeavors will require many billions of dollars in capital to complete.

Q. Why is approval of the FAC in this case so important?

A. As explained in detail in the testimony of several other AmerenUE witnesses, due to forces that are largely beyond the Company's control, we are facing significant increases in fuel expenses over the next several years at least. Without an adequate mechanism to timely recover these cost increases, AmerenUE will not have any reasonable opportunity to earn its authorized return on equity now or in the foreseeable future. This is explained in detail in the testimony of Mr. Lyons.

Q. Why doesn't the traditional ratemaking process provide an adequate mechanism for AmerenUE to recover its fuel costs?

A. Again, the effect of regulatory lag means that AmerenUE will always face a significant time lag in recovering fuel cost increases. Because of the magnitude of the Company's fuel costs, its failure to recover even a small percent of those costs will have significant adverse impact on its earnings. For example, during the last rate case AmerenUE fuel costs increased significantly in January 2007. Although the Company was permitted to include these increases in the true-up of our cost of service, AmerenUE's rates did not reflect these fuel cost increases until June 2007, which resulted in the under-recovery of tens of millions of dollars of fuel costs between January and June, 2007. It is this kind of under-recovery of costs that, over time, would undermine AmerenUE's financial health and access to capital markets, jeopardizing its ability to invest in its system. In addition to adversely affecting earnings, such an under-recovery of costs compromises the Company's cash flows, further straining its financial health and limiting its access to credit. We compete for credit with other vertically integrated electric utilities in the Midwest and throughout the country, the vast majority of which already have FACs. I can't overemphasize the importance to the Company and its customers of having a reasonable FAC, to put AmerenUE on the same footing as other utilities with which it must compete.

Q. Can't AmerenUE mitigate the uncertainty and volatility of its fuel costs through hedging strategies?

A. Only to a very limited degree. AmerenUE has sophisticated price hedging programs for every major component of its fuel costs. However, these hedging programs do not eliminate the substantial uncertainty and volatility in net fuel costs. Indeed, in the coming years there remains a significant, un-hedged quantity of fuel that the Company will have to buy to generate electricity for its customers. In addition, a large component of net fuel costs is off-system sales revenues, which are very volatile and which, for the most part, cannot be hedged. As discussed in detail in the direct testimonies of several AmerenUE witnesses (Messrs. Neff, Glaeser, Irwin, Schukar and Ajay K. Arora), there is substantial uncertainty surrounding these un-hedged quantities of fuel and off-system sales, which in turn means that net fuel costs could vary widely from so-called "expected" costs. Without an FAC, this volatility and uncertainty in the significant un-hedged portion of AmerenUE's net fuel costs could cause the Company to recover more than its net fuel costs in a given year or, given the significant fuel cost increases that are expected to occur in the near term, will more likely cause the Company to under-recover its net fuel costs. The rising cost environment in which the Company, like the rest of the industry, is operating today, coupled with an inability to fully recover its net fuel costs, will deprive the Company of a sufficient opportunity to earn a fair return on equity. An FAC will improve the Company's chances of earning its authorized rate of return, ensuring that it does not under-recover or over-recover its net fuel costs. This is fair and beneficial for the Company and for its customers.

Q. Given your concerns about regulatory lag, why is AmerenUE not requesting an environmental cost recovery mechanism ("ECRM") in this case?

A. The main reason that we did not seek an ECRM in this case is that, in the near term, AmerenUE is not facing any major new environmental costs that cannot be captured in base rates set in this case. The Sioux Plant scrubber is scheduled to come on line near the end of 2009. However, by that time the rising costs we are facing will very likely necessitate another rate case. We plan to include the Sioux scrubber in that case, provided it is in service. In that case we will also consider asking for an ECRM.

Another reason why we are not requesting an ECRM in this case is that we are not sure exactly how the ECRM will be implemented. The rules were just enacted recently. Unfortunately, they require a very impractical segregation of existing environmental rate base. While there have been indications that the rules could be changed to address this problem, we are, at this point, not sure how the ECRM rules will work or what the impact of any rule changes will be. The rules also permit the Commission to adopt, reject or modify the filed ECRM. We want to see how the ECRM is going to be implemented before we propose one.

VI. COMPANY WITNESSES

Q. Would you please introduce the other witnesses who will be providing direct testimony in this case?

A. Yes. In addition to myself, the following witnesses are providing direct testimony for the Company in this case, addressing the indicated subject areas:

Richard Mark	Reliability Issues
Kenneth Gordon	Industry Perspective
Gary S. Weiss	Cost of Service
Martin J. Lyons, Jr.	Fuel Adjustment Clause
Robert K. Neff	Coal Costs
Scott A. Glaeser	Natural Gas Costs
Randall J. Irwin	Nuclear Fuel Costs
Shawn E. Schukar	Off-System Sales
Ajay K. Arora	Net Fuel Cost Uncertainty
Timothy D. Finnell	Normalized Test Year Fuel Costs
Paul W. Mertens	Fuel Accounting for the FAC
Mark C. Birk	Heat Rate Testing for the FAC
Prof. Roger A. Morin	Return on Equity
Michael G. O'Bryan	Capital Structure; Overall Return on Rate Base
Steven M. Wills	Weather Normalization
Michael Adams	Cash Working Capital
Wilbon L. Cooper	Rate Design, Billing Units
William M. Warwick	Class Cost of Service Study
James R. Pozzo	Normalized Billing Units
Edward C. Pfeiffer	FERC 7-Factor Test for Transmission

I have attached the executive summaries of these witnesses' testimonies as Schedule TRV-E6 to my testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2008-____

AFFIDAVIT OF THOMAS R. VOSS

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Thomas R. Voss, being first duly sworn on his oath, states:

1. My name is Thomas R. Voss. I work in St. Louis, Missouri, and I am employed by AmerenUE as President and Chief Executive Officer.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 22 pages, and Schedules TRV-E1 through TRV-E6, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Thomas R Voss
Thomas R. Voss

Subscribed and sworn to before me this 4th day of April, 2008.

Danielle R. Moskop
Notary Public

My commission expires: ____________

Danielle R. Moskop
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: July 21, 2009
Commission # 05745027

QUALIFICATIONS OF THOMAS R. VOSS

My name is Thomas R. Voss. I am employed as President and Chief Executive Officer of AmerenUE.

I graduated in 1969 with a Bachelor of Science in Electrical Engineering from the University of Missouri – Rolla. In addition, I am a graduate of the University of Michigan's Public Utility Executive Program and the Westinghouse Advanced Power Systems School in Pittsburgh. In 2001, the University of Missouri – Rolla awarded me with an honorary Professional Degree in Electrical Engineering. I am a registered professional engineer in Missouri and Illinois. I also hold an electrical contractor's license in St. Louis City and County and have been a member of the Institute of Electrical and Electronic Engineers for over 36 years.

I began my career with Union Electric Company in 1969 as a student engineer. After four years as an officer in the United States Air Force, I returned to Union Electric Company as an assistant engineer. From 1975-1987, I held a series of positions including engineer, staff engineer, superintendent and finally district manager. In 1988, I was named Manager of Distribution Operating. In July 1998, I was named Vice President Regional Operations – AmerenCIPS. In June of 1999, I was named Senior Vice President – Energy Delivery of Ameren Services Company. On January 1, 2007, I was named President and Chief Executive Officer of AmerenUE.

During my career, I have had the responsibility for establishing the Network Meter Reading system in the St. Louis metropolitan area and have managed system-wide metering, forestry (i.e. tree trimming and other vegetation management activities) and dispatching. I also was responsible for introducing state-of-the-art outage analysis and supervisory control and data acquisition systems.

ACTUAL EXPENDITURES
UNION ELECTRIC 2003-2007

(in millions)

	2003	2004	2005	2006	2007 final
GENERATION*	$ 168	$ 256	$ 268	$ 136	$ 197
Combustion Turbines (new generation)	$ 76	$ 21	$ 237	$ 292	$ -
TRANSMISSION	$ 36	$ 28	$ 33	$ 11	$ 28
DISTRIBUTION + OTHER	$ 171	$ 203	$ 210	$ 299	$ 283
ENVIRONMENTAL **	$ 11	$ 19	$ 14	$ 73	$ 107
Expenditure Totals	$ 460	$ 527	$ 762	$ 811	$ 615
accrual and removal adjustments	$ 20	$ (13)	$ 13	$ (29)	$ 10
Capex TOTAL as reported in 10K	$ 480	$ 514	$ 775	$ 782	$ 625

Expenditure totals include all capital costs and removal expenses associated with the projects

* *Generation projects include coal, gas, hydro, nuclear*

** *Environmental projects include all projects related to environmental compliance including emissions, particulate, water*

BUDGETED EXPENDITURES
UNION ELECTRIC 2008-2012
(in millions)

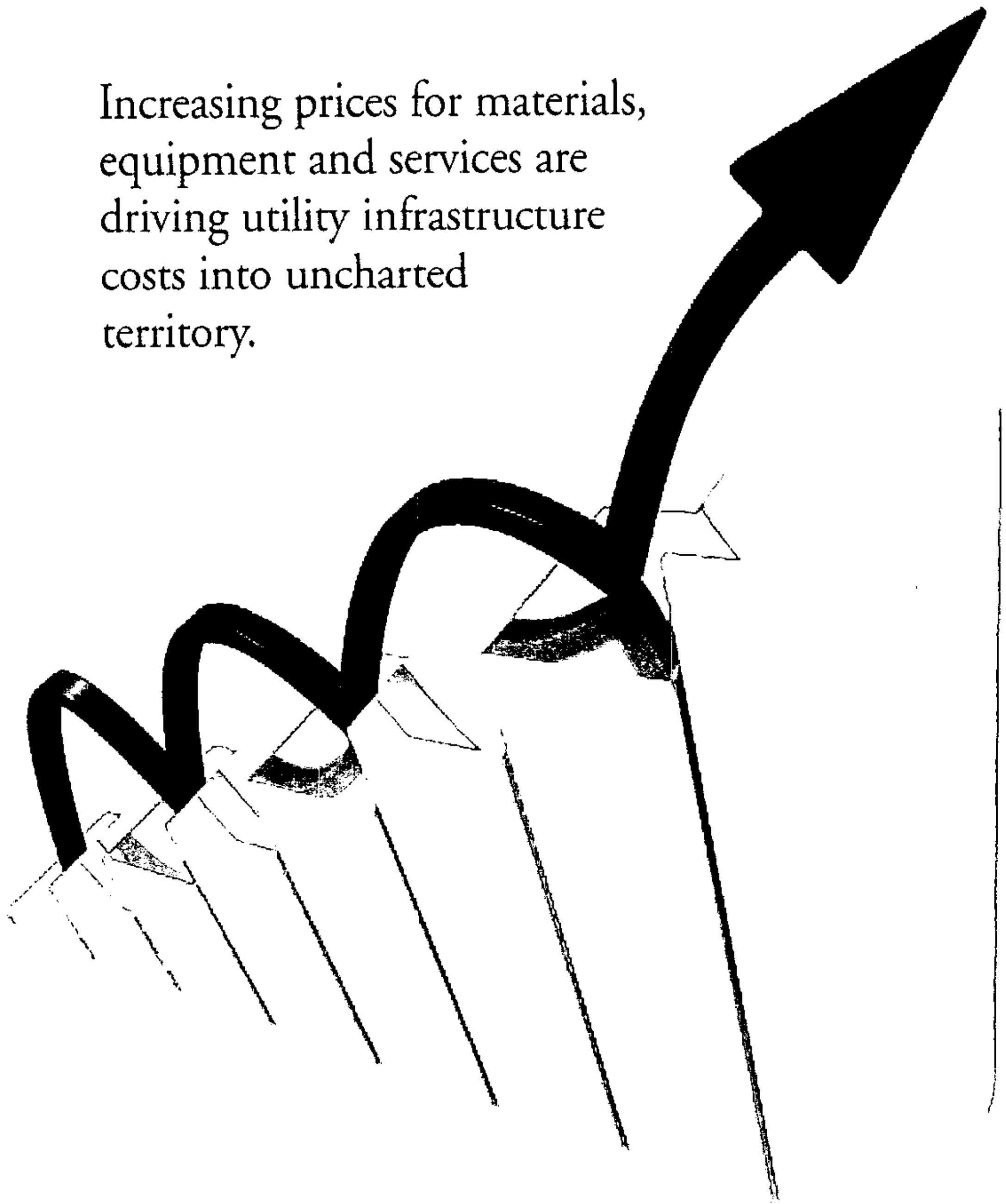
	2008	2009	2010	2011	2012
GENERATION*	$ 331	$ 322	$ 293	$ 265	$ 212
TRANSMISSION	$ 41	$ 26	$ 52	$ 26	$ 2
DISTRIBUTION + OTHER	$ 391	$ 372	$ 388	$ 400	$ 397
ENVIRONMENTAL **	$ 280	$ 174	$ 58	$ 52	$ 244
TOTAL	$ 1,042	$ 894	$ 791	$ 743	$ 856

Expenditures include all capital costs and removal expenses associated with the projects

** Generation projects include coal, gas, hydro, nuclear but exclude construction costs related to the second Nuclear unit at Callawy*
*** Environmental projects include all projects related to environmental compliance including emissions, particulate, water*

STICKER SHOCK!

Increasing prices for materials, equipment and services are driving utility infrastructure costs into uncharted territory.



BY GREG BASHEDA AND MARC CHUPKA

Schedule TRV-E3-1

By now, the evidence is overwhelming. Utility-industry construction costs have risen and will remain elevated for some time.

Some of the factors underlying these trends are straightforward. For example, costs for steel, copper and concrete have risen sharply due to high global demand, as well as production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar. Other drivers are less transparent. Labor costs generally have tracked inflation rates, but shortages in skilled workers have driven costs higher for utility equipment and construction services.

Moreover, constraints in component-manufacturing capacity as well as engineering, procurement and construction (EPC) services exacerbate cost pressures. In January 2007, for example, OG&E executives reported that the cost estimate for EPC services for building the company's proposed Red Rock coal-fired power plant increased by more than 50 percent in just nine months, from $223 per kilowatt to $340/kW.[1]

Although customers will not see the full rate impact associated with construction cost increases until infrastructure projects are completed, these increases now are affecting industry investment plans and presenting new challenges to regulators.

The recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to a growing sense of sticker shock among power companies and state regulators.

Moreover, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA) *2007 Annual Energy Outlook (AEO)*, leading to a substantial divergence between EIA's data assumptions and market evidence. For example, the *AEO* estimates construction costs for advanced nuclear plants at just over $2,000/kW, but a recent report from Moody's Investors Service forecasts costs between $5,000 and $6,000/kW—three times the EIA figures.[2]

To provide reliable indicators of current or future capital costs, the Edison Foundation commissioned the Brattle Group to study recent increases in the costs of building utility infrastructure—including generation, transmission and distribution facilities. The study also identified the causes of these increases and explained how these increased costs will translate into higher consumer rates.[3]

The overall effects will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases.

Predicting the Wave

Construction-cost inflation during the past several years has reached every corner of the electric utility industry.

Infrastructure costs were relatively stable during the 1990s. But between January 2004 and January 2007, prices increased rapidly. Costs for steam-generation boilers, transmission facilities and distribution-grid equipment rose by 25 percent to 35 percent, compared to an 8 percent increase in inflation, expressed by the GDP deflator[4] (*see Fig. 1, "National Average Utility Infrastructure Cost Indices"*).

Recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen.

The cost of gas turbines increased by 17 percent during 2006. Similarly, prices for line transformers and pad transformers increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[5]

These rapid cost increases have raised the price of recently completed infrastructure projects. To the extent services and materials were acquired before the most recent inflationary trends, the effect has been mitigated somewhat. Rising prices have a more dramatic effect on the estimated cost of proposed projects, which fully include the recent price trends (*see sidebar, "Ballooning Project Costs"*).

As a result, utilities and regulators increasingly are worried the next wave of utility investments might cause rates to increase significantly. Rising construction costs and recent increases in wholesale power prices have motivated industry participants to more actively pursue energy-efficiency and demand-response initiatives, to reduce future consumer-rate increases. Nevertheless, economic growth and the need to replace aging infrastructure will necessitate major new investments during the next two decades.

According to EIA's most recent projections, U.S. electricity sales are expected to grow by about 1.4 percent each year through 2030, and the North American Electric Reliability Corp. (NERC) forecasts peak demand will grow by 19 percent, or 141 GW, from 2006 through 2015. EIA predicts power companies will need to build 258 GW of new generating capacity by 2030 to meet demand growth and replace plants that will be retired.

Likewise, the high-voltage transmission grid requires sig-

Schedule TRV-E3-2

nificant investment. After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since then, the industry has invested more than $37.8 billion in the nation's transmission system, and a recent Edison Electric Institute (EEI) survey suggests its members plan to invest $31.5 billion in the transmission system from 2006 to 2009. NERC anticipates nearly 13,000 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America between 2006 and 2015.

The construction industry must recruit 200,000 to 250,000 new craft workers each year to meet future needs.

Similarly, distribution-system investments began rising in the mid-1990s, preceding the corresponding boom in generation, and the flow of distribution investments shows no sign of diminishing. In 2006, utilities invested more than $17 billion to upgrade and expand distribution systems, a 32 percent increase over investments in 2004. EEI estimates distribution investment during 2007 will again exceed $17.0 billion.

While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of this investment reflects the increased input costs of materials and labor. Cost estimates likely will increase further if market trends persist.

Weighing the Costs

Using commercially available databases and other sources, such as financial reports, press releases and government documents, the Brattle Group collected data on installation costs for natural-gas-fired combined-cycle generating plants brought into service in the United States between 2000 and 2006, and found the average real construction cost was approximately $550/kW in 2006 dollars, with a range of costs between $400/kW and about $1,000/kW. Statistical analysis confirmed real installation cost was influenced by plant size,

Ballooning Project Costs

Recent utility rate cases and project updates illustrate the rising cost of equipment, materials and construction services for U.S. utility infrastructure.

- **Big Stone II:** Otter Tail Power Co. and a consortium of seven Midwestern utilities initially expected to spend $1.2 billion for the 630-MW Big Stone II coal-fired power plant and an associated transmission line. Increasing costs for materials and labor have driven the cost upward, and more recent estimates place the total cost for Big Stone II at $1.6 billion.

- **Duke Cliffside:** In June 2006, Duke Energy petitioned the North Carolina Utilities Commission to grant a certificate of public convenience and necessity to build two 800-MW coal-fired units at the site of the existing Cliffside Steam Station. Duke's preliminary cost estimate showed the two units would cost approximately $2 billion. Five months later, Duke revised the cost estimate to $3 billion. Later, after the commission approved only one of the two units, Duke estimated construction costs for the single 800-MW unit would be about $1.8 billion, or $2,250/kW.

- **OG&E Red Rock:** In September 2006, Oklahoma Gas & Electric Co. revised its cost estimate for the 950-MW Red Rock coal-fired power plant from nearly $1,700/kW to more than $1,900/kW, a 12-percent increase in just nine months. In its testimony to the Oklahoma Corporation Commission, OG&E said its estimate for the engineering, procurement and constructruction service portion of the plant increased by more than 50 percent during the nine-month period (from $223/kW to $340/kW). In September, the commission rejected OG&E's request to pre-approve the project as a prudent rate-base investment.

- **Westar Deferral:** In December 2006, Westar Energy announced it would defer its plans for a new 600-MW coal-fired plant due to significant increases in the estimated construction costs, which increased from $1 billion to about $1.4 billion since the plant was first announced in May 2005.

- **FutureGen:** DOE announced earlier this year the projected cost for one of its most prominent clean-coal demonstration projects, FutureGen, had nearly doubled. Initial costs for the integrated gasification combined cycle and carbon-sequestering project were estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced the project's price increased to $1.7 billion.

- **Boston Transmission:** NSTAR recently built two 345-kV lines from a switching station in Stoughton, Mass., to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million.—***GB and MC*** the turbine technology, the NERC region in which the plant was located, and the commercial online date.

Notably, the data showed a positive and statistically significant relationship between a plant's real construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[6] The average installation cost increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant-construction costs.

Another major class of generation development during this decade has been wind generation, the costs of which also have increased in recent years. The Northwest Power and Conservation Council (NPCC) issued its most recent review of the cost of wind power in July 2006.[7] The Council found the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than assumed in its most recent resource plan. Specifically, the Council found the construction cost of wind projects, in real dollars, has increased from about $1,150/kW to $1,300-$1,700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. The average cost of wind power plants now being developed is still higher, with construction costs estimated from $1,700/kW to $2,000/kW.[8]

Fig. 1 **National Average Utility Infrastructure Cost Indices**

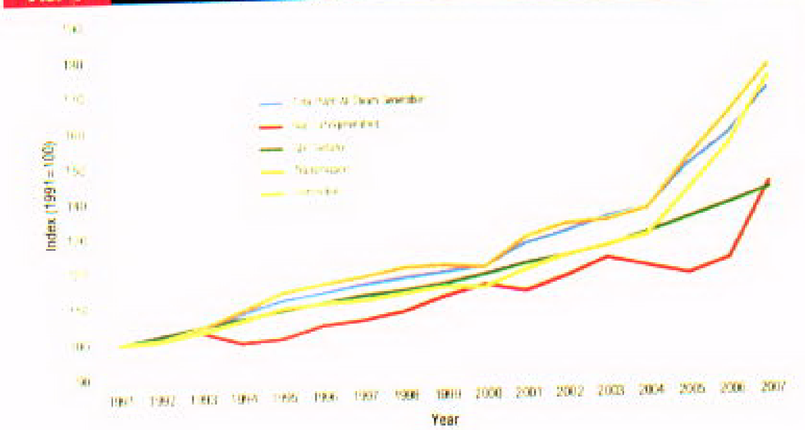
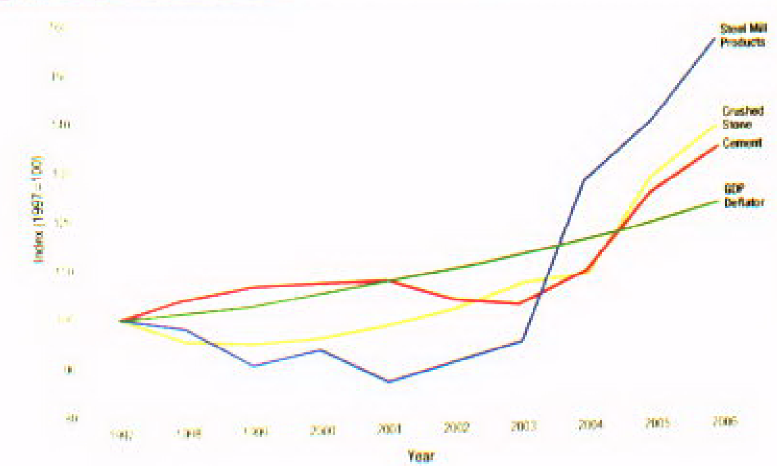


Fig. 2 **Raw Materials Costs**



Inflationary Inputs

Broadly speaking, four factors are driving rising costs for utility infrastructure: 1) material costs, including such commodities as steel and cement, as well as manufactured components; 2) limited shop and fabrication capacity for manufacturing major components; 3) costs for construction field labor, both unskilled and craft labor; and 4) the market for large construction-project management and EPC services.

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation (*see Fig. 2, "Raw Materials Costs"*). In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar affects domestic costs.

In particular, various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[9] Today's steel prices remain at historically elevated levels and likely will remain high for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases

Schedule TRV-E3-4

in the last few years. These price increases also were evident in other metals—such as nickel and tungsten—that contribute to steel alloys used broadly in electrical infrastructure. Prices for wire products have spiked compared to the inflation rate, highlighting the impact of underlying metal price increases (*see Fig. 3, "Electric Wire and Cable Price Indices"*).

Fig. 3 **Electric Wire and Cable Price Indices**

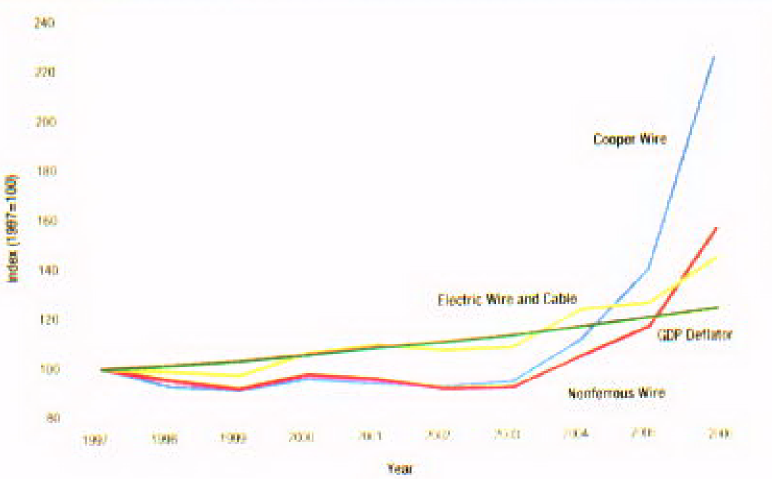


Fig. 4 **National Average Labor Costs Index**

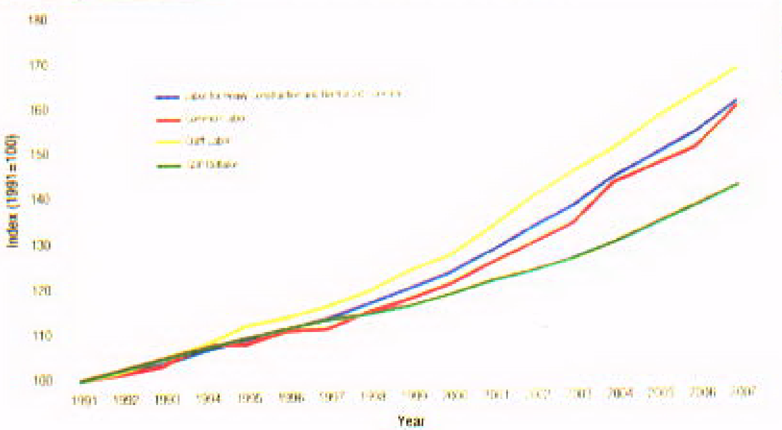
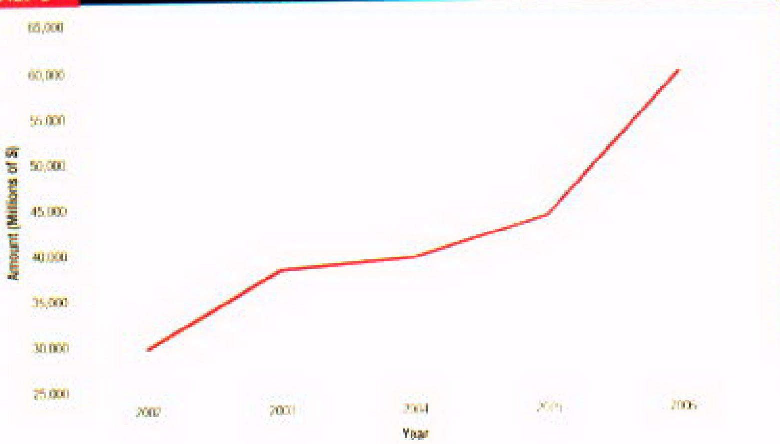


Fig. 5 **Annual Backlog at Major EPC Firms**



In addition to metals, large infrastructure projects require huge amounts of cement as well as basic stone materials. And the price of these commodities has risen substantially in the past few years, for the same reasons cited above for metals. Cement in particular is an energy-intensive commodity that is traded in international markets, and recent price patterns resemble those displayed for metals.

Likewise, prices for plant components, such as large pressure vessels, condensers, pumps and valves, have risen sharply since 2004. While equipment and component prices reflect underlying material costs, some price increases and delivery lags are driven by manufacturing capacity constraints. Recent orders largely have eliminated spare shop capacity, and delivery times for major manufactured components have risen as a result.

To the degree delays in component deliveries cause construction schedules to lengthen, financing costs likewise will increase—with commensurate effects on overall plant costs.

Building Backlog

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor, including pipefitters and electricians. Labor cost increases—while less dramatic than those experienced by commodities—nevertheless have exceeded the general inflation rate (*see Fig. 4, "National Average Labor Costs"*).

Specifically, between January 2001 and January 2007, overall inflation caused general prices to rise by about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent.[10]

Although labor costs have not risen dramatically in recent years, utilities increas-

Schedule TRV-E3-5

ingly are concerned about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem.

The industry always has suffered high attrition at entry-level positions, but now many workers in the 35 to 40 year-old age group are leaving the industry for a variety of reasons. As a result, the construction industry must recruit 200,000 to 250,000 new craft workers each year to meet future needs. Both demographics and a poor industry image are working against the construction industry as it tries to address this need.

Similar issues might affect the supply of electrical lineworkers who maintain the electric grid and perform labor for T&D investments. DOE forecasts qualified candidates might fall short of requirements by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce.[11] Such shortages likely will place upward pressure on the wages earned by lineworkers.

Finally, conditions in the market for EPC services are driving major cost increases. While the Brattle Group was unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects, these companies' financial statements specify the financial value associated with their backlog of infrastructure projects.

The cumulative annual financial value associated with the backlog of infrastructure projects at four major EPC firms—Fluor Corp., Bechtel Corp., The Shaw Group and Tyco International—rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent *(see Fig. 5, "Annual Backlog at Major EPC Firms")*. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general, including utility generation, transmission, and distribution projects.

Growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. Although difficult to quantify, this lack of spare capacity in the EPC market undoubtedly will inflate the price of new bids for EPC services and contracts.

These factors, as well as the other inflationary pressures beyond the utility industry's control, have contributed to an across-the-board increase in the costs of investing in utility infrastructure—and those higher costs show no immediate signs of abating.

Paying the Price

As a result of the undeniable need for additional infrastructure, utilities and non-utility developers will continue investing in baseload generation, environmental controls, transmission projects and distribution systems. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. For example, the increasing fixed costs of base-load coal and nuclear facilities have reduced the cost savings the industry anticipated from expanding the solid-fuel fleet.

The overall impact on the industry and on customers will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for increasing construction costs. Most directly, these costs will result in higher rates to recoup asset investments, and less directly, higher energy-market prices to attract new generating and transmission capacity in organized power markets. And customers will pay indirectly, when rising construction costs inevitably defer investments and delay expected benefits, such as enhanced reliability and lower, more stable long-term electricity prices.

Greg Basheda (gbasheda@brattle.com) is a senior consultant and Marc Chupka (Marc.Chupka@brattle.com) is a principal with the Brattle Group in Washington, D.C.

ENDNOTES

1. Testimony of Jesse B. Langston before the of the Oklahoma Corporation Commission, *Cause No. PUD 200700012*, Jan. 17, 2007, p. 27 and Exhibit JBL-9.
2. "New Nuclear Generation in the United States: Keeping Options Open vs. Addressing an Inevitable Necessity," Moody's Investors Service, Oct. 10, 2007.
3. Chupka, Marc W. and Basheda, Gregory, *Rising Utility Construction Costs: Sources and Impacts*, Edison Foundation, September 2007.
4. The GDP deflator measures the cost of goods and services purchased by households, industry and government, and is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.
5. *Ibid.* Chupka.
6. To be precise, the authors used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.
7. "Biennial Review of the Cost of Windpower" July 13, 2006, *www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc/.*
8. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*, U.S. DOE, May 2007, pp. 15-16.
9. *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, Aug. 31, 2006.
10. These figures represent a simple average of six regional indices. However, local and regional labor markets can vary substantially from these national averages.
11. *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress*, Pursuant to Section 1101 of the Energy Policy Act of 2005, U.S. Department of Energy, August 2006, p. xi.

Schedule TRV-E3-6

Commissioners

JEFF DAVIS
Chairman

CONNIE MURRAY

STEVE GAW

ROBERT M. CLAYTON III

LINWARD "LIN" APPLING

Missouri Public Service Commission

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ROBERT SCHALLENBERG
Director, Utility Services

WARREN WOOD
Director, Utility Operations

COLLEEN M. DALE
Secretary/Chief Regulatory Law Judge

KEVIN A. THOMPSON
General Counsel

December 6, 2006

Mr. Gary Rainwater
Ameren Chairman, CEO and President
P.O. Box 66149
Mail Code 01
St. Louis, MO

Dear Mr. Rainwater,

On December 5, 2006, Mr. Thomas R. Voss met the Commission in their Agenda session. Mr. Voss attended the Commission's Agenda session to provide an update on ice storm restoration efforts in St. Louis and to respond to Commissioner questions and concerns.

The Commissioners expressed several concerns with the number of customers without service, how long they have been without service and most importantly, how many major outages AmerenUE has experienced in the last three years. While storm damage is a recognized contributor to major outages, the frequency and severity of these outages is clearly unacceptable to the Commission. The Commission is clearly frustrated with this situation and is urgently requesting that AmerenUE propose approaches to reduce the duration of outages AmerenUE's customers are experiencing due to storm damage. All possible approaches to address this situation should be considered by AmerenUE. AmerenUE should not limit its possible approaches to only those permissible under current statutes or the recommendations made by the Staff in its report filed on November 17, 2006. The Commission would entertain legislative or other approaches to this problem. The Commission would also be interested in any cost estimates to implement any proposed AmerenUE program.

During these discussions Commissioner Gaw requested that AmerenUE also provide the Commission with specific information on what AmerenUE is doing to help customers without power. As an example of the hardships this situation creates, Commissioner Gaw noted the difficulty this situation creates for livestock and the ability to provide them with water when a well depends on electricity to operate.

More specifically, in Mr. Voss' report he noted that not as many utility poles failed in this winter storm and that more wires failed. Please provide the PSC Staff with the total number of AmerenUE poles that failed as a result of the storms on November 30 and December 1, 2006. Please also provide PSC Staff with the total number of miles of conductors that were replaced as a result of these storms.

The Commission has given AmerenUE until January 4, 2007 to respond to these requests. If you have any questions regarding this matter, please e-mail me at Warren.Wood@psc.mo.gov or call me at (573) 751-2978 or Wess Henderson at Wess.Henderson@psc.mo.gov or call Wess at (573) 751-7435.

Sincerely,

Warren T. Wood

Warren T. Wood, PE
Director, Utility Operations Division

cc: Wess Henderson, Executive Director
Lena Mantle, Energy Department Manager
Mr. Thomas R Voss, Ameren Exec. Vice President and Chief Operating Officer
Chairman Jeff Davis
Commissioner Lin Appling
Commissioner Robert Clayton
Commissioner Steve Gaw
Commissioner Connie Murray

AmerenUE

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314.621.3222

January 4, 2007

Mr. Jeff Davis, Chairman
Missouri Public Service Commission
Governor Office Building
200 Madison Street
Jefferson City, MO 65102

Ameren UE

Dear Chairman Davis:

This is in response to Mr. Warren Wood's December 6, 2006, letter to Gary Rainwater that outlined a request from the Missouri Public Service Commission to offer potential actions that AmerenUE could take to improve the reliability of electric service, in particular during severe weather events. A uniquely devastating combination of two tornado-laden summer storms within two days of each other, followed four months later by the worst ice storm this region has seen in almost 30 years, has prompted this request. I understand the frustration AmerenUE customers have faced and the frustration the Commission sees in dealing with such complex and uncontrollable events. Customers' expectations in the 21st century are very high, and we want to explore the ways and issues to meet these expectations. We appreciate the Commission's inquiry and look forward to a constructive dialog on the issues raised by these storms.

From our perspective, a discussion of issues surrounding system reliability is not simply a discussion of what can be done to prevent significant outages during a severe storm. As we have witnessed in the Midwest, the Gulf Coast and more recently the Northwest, severe storms cause significant outages in terms of number of customers and duration. The results of severe storms do not necessarily show that a distribution system is poorly designed or maintained. Instead, they show that severe storms have severe results.

Second, AmerenUE's storm response was immediate and well executed. The Commission Staff in its November 17, 2006 report on the July storms said "AmerenUE's planning process was well developed" and "AmerenUE's restoration effort was well executed." We agree. Yet when looking at the overall weather situation for 2006, the National Oceanographic and Atmospheric Administration's weather forecast office in St. Louis reported experiencing more severe weather than any other office in the National Weather Service this year, with a total of 723 severe weather events recorded.

Third, AmerenUE's present tree trimming policies or schedule were not an overriding factor in these storms. Some of the most severe damage and lengthy customer outages in the July 2006 storm were in an area recently trimmed. In Illinois, Ameren is on a four-year trim cycle, and 235,000 customers still lost service in the November 30 – December 1 ice storm. A new tree removal program and more aggressive trimming approach that will require customer consent may be needed, along with full and timely rate recovery of incurred costs, to appropriately address the threat trees have on the electric system during severe storms.

I am convinced there is no simple solution or immediate action that can be taken to solve the problem of extreme weather damage. However, I agree it is appropriate to start a public dialog to determine future actions and investments that are necessary to "harden" the AmerenUE system.

In response to the issues raised in Mr. Wood's December 6, 2006, letter, we have assembled the attached list of possible programs, process changes, and regulatory/legislative approaches to address customer needs and desires on a going-forward basis. Also attached for convenience is a copy of AmerenUE's December 26, 2006, response to Mr. Wood's December 7, 2006, letter to me requesting specific data from the November 30 – December 1 ice storm.

The attached list of possible approaches to improve customer reliability in severe storms includes ideas that vary in perspective from shorter term to longer term, although we have not attempted to separate them into categories. Also, while the list is extensive, it is not exhaustive. There are many ways to improve reliability, some with smaller impacts and some with larger impacts. I believe that one key to success will be in working with the Commission to determine the best public policy approach to investment in greater reliability. AmerenUE supports many of the recommendations found in the November 17, 2006, Staff report on the July 2006 storms as discussed in our December 21, 2006, response to that report. We will continue to address the findings from the July 2006 storms as called for in our response, regardless of the conclusions reached about the November 30 – December 1 ice storm. If the Commission ultimately decides that increased reliability during severe weather events is needed, the attached list of approaches can form the basis for addressing that desire.

As you know, in each major storm event, AmerenUE coordinates with public service agencies, state and local government agencies, and emergency response groups to assist customers with special needs. A part of this effort establishes priority restoration for particular customers identified by these agencies. However, for many of these customers priority restoration will not be enough, and they must have an alternative in place or rely on customer-owned generation. Commissioner Gaw's point about livestock owners will most likely fall in this last category. As one way of dealing with this issue, we have included customer generation options in the list of possible approaches.

AmerenUE is currently in the process of selecting a consultant who has had experience evaluating storm response protocols and making recommendations to harden the distribution systems of other utilities. This consultant will help craft and evaluate the approaches outlined in the attached list, as well as develop other approaches based on their experience and evaluation of the AmerenUE system. The consultant will also review the elements of AmerenUE's storm response processes and plans. I anticipate that the study phase of this effort will be completed in approximately six months. AmerenUE will report back to the Commission when the consultant is in place and periodically as this work unfolds.

Finally, it is important to note that the ultimate reliable delivery of electric service to our customers requires continued investment in generation and transmission infrastructure, in addition to the distribution system that is the primary focus of this letter. While the recent storms have not had a significant impact on generation or transmission facilities, AmerenUE will need to continue to invest in significant additions to generation and transmission facilities in order to meet the needs of our customers in Missouri, including potentially a new base load generating plant.

As you can imagine, many of the approaches to improve reliability that may be chosen for implementation will require additional resources from the company, from local communities, and from AmerenUE customers. We will need to engage in a constructive dialog with the Commission and other entities on innovative ways to make sure those resources are available and appropriately funded. In the same spirit as your request that we consider all alternatives to improve reliability, we should consider all options for financing them. This might include special riders, recovery of construction work in progress, forward looking rate base adjustments with annual true-ups, cost sharing with state and local government bodies, location specific/customer specific rate allocation, rate base socialization, and other innovative financing means.

In conclusion, I welcome the Commission's inquiry because it provides an important opportunity for stakeholders to engage in constructive dialog around the complex issues associated with system reliability.

Sincerely,

Thomas R Voss

Thomas R. Voss, P.E.
President & Chief Executive Officer
AmerenUE

Attachments

cc: Commissioner Linward Appling
Commissioner Robert Clayton
Commissioner Steve Gaw
Commissioner Connie Murray
Mr. Wess Henderson
Mr. Warren Wood
Ms. Lena Mantle

Attachment A

Possible Approaches To Improve Customer Reliability In Severe Storms

The list below includes preliminary ideas and concepts for improving customer reliability during severe storms. Each idea will require further work to determine potential benefits, costs, and barriers to implementation. The first three items alone are not a solution. However, they are positive first steps and can be started while further development work proceeds on the other nine approaches.

Approaches That Can Be Started Quickly

1. Recommendations from July 2006 Storms

Implement the recommendations of the November 17, 2006, Missouri Commission Staff report on the July 2006 storms as described in AmerenUE's response dated December 21, 2006.

2. Implement and Fund Measures Recommended in AmerenUE's Rate Case

As described in AmerenUE's filed testimony related to reliability improvement, approve and fund the following opportunity:

- Approve $15 million annual tree removal program and more aggressive trimming, with future increased funding depending upon customers' acceptance.

In addition, approve and fund the following opportunities:

- Approve funds for a full pole inspection program.
- Approve funds for completion of the tap fusing program.
- Approve funds for new line inspection program.

3. Improve Customer Systems/Communications

Improve the responsiveness, data collection, and information flow in AmerenUE's present customer service systems to assist in restoration efforts and provide customers with more accurate, timely, and complete information. Specifically:

- Enhance outage information communication with customers, including improved estimated restoration times, outage cause, and progress toward completing restoration.
- Improve the Outage Analysis System for internal AmerenUE use to correct errors and work-arounds, location of records, and upgrading analysis capabilities.
- Allow customers to report outages via the internet.

- Improve usability of automated meter reading data during outage restoration.
- Increase public awareness programs associated with trees and service drop responsibilities.
- Increase the information provided to customers about planting the right tree in the right place so as to avoid future conflicts and vegetation costs.

Approaches That Require Further Development/Consideration

4. Modify AmerenUE Tariff to Reflect Underground Imperative

Change the approach to all future construction on the distribution system to require underground installation versus the combined overhead/underground approach used today. Currently, new 3-phase facilities are typically built using overhead construction unless there are engineering reasons for placing them underground or if another party pays for the difference in cost. New subdivision facilities are installed underground. This policy would be changed to require that all new distribution facilities are buried as the preferred method unless there are overriding engineering reasons to the contrary.

As of March 2006, AmerenUE had 26,800 miles of distribution overhead circuits with voltages between 1kV and 100kV and 6,600 miles of underground circuits of the same voltage classes – about an 80/20 mix. Over the past two years, AmerenUE has installed an average of 106 miles of overhead circuits annually compared to 262 miles of underground circuits – a 30/70 mix. From a new construction standpoint in terms of number of miles, AmerenUE is already predominately an "underground" utility. The possible approach here would be to extend that to 100% underground for new distribution facilities. However, it is important to note that the remaining 30% will predominately be 3-phase circuits, many along roadways that will be more expensive to construct.

5. Implement a Program to Place Existing Overhead Distribution Facilities Underground

Systematically start replacing a certain amount of the existing 26,800 miles of overhead circuits with underground circuits. Analysis would be required to determine the best approach to choosing which circuits are addressed first.

6. Implement a Program to Place All New Customer Services Underground

This idea involves working with various municipalities to develop local ordinances that would require all new and upgraded services to be located underground. For example, in St. Louis County about half of the municipalities require underground service for new and upgraded services. This idea would extend that to all AmerenUE service areas.

7. **Implement a Program to Place All Existing Customer Services Underground**

Systematically start to replace existing customer services underground. This is essentially an extension of #6 above, although the implications are more extensive. In this case, customers would likely have make-ready work on their electric service entrance. The program could be approached from two directions: providing customers an option of converting to underground or making the conversion mandatory. Analysis would be required to determine the best approach to prioritizing the locations and number of services to be addressed each year. Coordination with local municipalities and customer groups would be essential for this program to be a success.

8. **Rebuild Higher Voltage Distribution Circuits (34kV and 69kV) to a More Robust Design**

The higher voltage distribution circuits supply distribution substations that generally connect to thousands of customers. If these circuits are damaged, more customers are impacted. While priority is given to these circuits for restoration, providing a more robust design would reduce outages to large numbers of customers. As an example, during the July 2006 storms, there were 73 extended outages on 57 different 34kV circuits on the AmerenUE system. These outages resulted in over 143,000 customer interruptions. This approach would systematically rebuild the higher voltage distribution circuits to a substantially more robust design.

While AmerenUE's existing designs meet or exceed National Electric Safety Code standards, there are options to make the design of these circuits more robust. These options include strengthening the structures using stronger poles, framing and hardware to withstand much higher wind and ice conditions and expanding the cleared area around the circuits to reduce tree related outages. Analysis would be required to determine the best approach to choosing which circuits are addressed first and how they would be modified/rebuilt. Another option would be placing these circuits underground as described in #5 above.

A subcategory of this approach would be to change the design of new circuits only and not systematically replace existing circuits.

9. Rebuild Lower Voltage Distribution Circuits (4kV and 12kV) to a More Robust Design

The lower voltage distribution circuits typically run down streets, alleys, and along customer property lines to provide direct supply to customers. As noted above, there are over 20,000 miles of these circuits on the AmerenUE system. While AmerenUE's existing designs meet or exceed National Electric Safety Code standards ("Grade C" construction on all facilities), there are options to make the design of these circuits more robust. These options include upgrading to "Grade B" construction on all circuits or just the main 3-phase sections of those circuits by using stronger poles, framing and hardware and expanding the cleared area around the circuits to reduce tree related outages. Analysis would be required to determine the best approach to choosing which circuits are addressed first and how they would be modified/rebuilt. Another option would be placing these circuits underground as described in #5 above.

A subcategory of this approach would be to change the design of new circuits only and not systematically replace existing circuits.

10. Implement an Extensive Circuit Rehabilitation and Rebuild Program

The purpose of this program would be to systematically evaluate the overall condition of circuits against the need for complete rebuild where the poles exceed 40 years of age. We know that the age of many poles is reaching the 40-year mark, and the results of the inspection program may indicate a growing need for complete replacement or repair of a majority of the circuit. Essentially, this is an extension of the existing pole inspection program and a more extensive application of inspections from that proposed in the existing AmerenUE rate case. Guidelines would be established for determining whether rehabilitation or rebuild would be required. This program could be used in conjunction with the options described in #8 and #9 above.

11. Provide for More Aggressive Vegetation Management Practices

This alternative would be a substantial change to existing vegetation management practices resulting in a more aggressive approach to tree trimming and removal. There are a number of alternatives that could be considered here including: acquiring new or expanded easements to provide greater clearing width, increasing space and rights along public street rights-of-way, aggressively removing danger trees with property owner consent, working with municipalities to establish a tree inspection program that tags dead and problem trees for removal by the property owner, establishing a "tree replacement" program to remove problem species with overhead line compatible species, determine what regulatory or legislative action is required to place responsibility for damage done by customer danger trees on the customer when danger tree removal is not allowed, and significantly increase customer education and awareness programs.

12. Develop a Customer Generator Installation Program

One of the reasons customers do not own an emergency generator to guard against impacts from severe weather is the initial cost and difficulty in hooking up the generator. This program could provide customers with access to an emergency generator and assure it is installed by a licensed electrical contractor with an appropriate anti-backfeed safety device installed. This would establish a premium level of service. Depending on the approach used, the program could eliminate all but the shortest momentary outages. Several approaches from permanent installations to providing a "rental pool" of generators can be considered, although considering the number of customers experiencing an interruption in recent storms, having a large enough "rental pool" may be a challenge.

An option to providing the generators, installation, and related services would be to provide residential customers with a safe, convenient way to connect a customer-owned generator to the home's existing wiring. This program would include a device that fits between the meter and the meter box and provides for the connection to the generator. Appropriate anti-backfeed safety devices would be included.

Discussion on this possible approach should include consideration of requirements and needs of special groups of customers, such as nursing homes.

EXECUTIVE SUMMARY

Richard Mark

Senior Vice President of Missouri Energy Delivery for Union Electric Company d/b/a AmerenUE

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AmerenUE has made important operational changes that will positively impact its customers. The Company has renewed efforts to improve both the reliability of its service to customers and its ability to restore power in a timely manner when it is interrupted. These efforts include a direct response to every customer-specific complaint expressed at local public hearings held in the Commission's storm investigation docket (Case No. EO-2007-0037) and in the Company's last rate proceeding (Case No. ER-2007-0002), organizational changes to improve identification and correction of areas where reliability improvements can be made, implementation of the Commission's recently adopted Infrastructure Inspection and Vegetation Management Rules, and the initiation of various reliability improvement programs, including Project Power On.

We are listening to our customers' concerns and working to respond to their needs. Historically, the Company has been focused on being a low-cost provider of electricity to its customers, as evidenced by the fact that AmerenUE's rates are among the lowest in the nation. It is now apparent that while our customers still expect us to provide electric service at a reasonable cost, the reliability of our electric service occupies an increasingly important role in our customers' satisfaction. We have taken on the challenge of improving the reliability of our electric service and are in the midst of implementing several programs to enable us to achieve that goal.

Throughout 2007, the Company held more than 525 meetings with individuals, community leaders, neighborhood associations, senior citizen centers, legislators and business owners to receive input on their concerns and to discuss how those concerns could be addressed. We are using that information to focus our efforts on improving reliability as promptly and cost-effectively as possible.

Organizationally, the Company has made several changes. We have restructured our Corporate Communications Department and set up a designated group to analyze customer information in order to identify and communicate improvement opportunities. The goal is to review and analyze various sources of customer input to allow the Company to better recognize and respond to the concerns of our customers.

The Company created a Reliability Improvement Department within AmerenUE. This places the responsibility for and oversight of our reliability projects in one area, which will enable a more consistent and effective approach to implementing reliability projects. We believe this will help to promote real reliability improvement for our customers.

AmerenUE has implemented several projects designed to help the Company improve the reliability of its system, including its most significant system investment program, called Project Power On (described in detail in my testimony). Beyond Project Power On, AmerenUE contracted with a consulting firm, KEMA, to obtain an independent, expert opinion on how the Company could harden its electric system to minimize service interruptions and to identify ways to improve system restoration after major storms.

AmerenUE is faced with a situation where it needs, more than ever, to clearly communicate with its customers so that its customers can be informed about the investment it is making in its electric distribution system and the other steps it is taking to improve reliability and to foster environmental stewardship.

Recent history demonstrates that we cannot rely on traditional methods of communication – a line on a customer's bill or a press release doesn't sufficiently convey the needed information to many of our customers. Thus we have undertaken a large customer communication effort which uses television, radio and billboards as well as detailed mailings to communicate to our customers our efforts to improve system reliability and to be good environmental stewards, including through Project Power On.

AmerenUE has redesigned a portion of its website to allow customers to access information about their specific outages. This information was available previously, but only to customers who had set up an account with a password. This proved to be inconvenient for many of our customers. Now customers can log onto our system using their phone numbers, and they are able to see the status of their service, although they will still need to create an account to access additional account information, such as billing information. There are additional website improvements scheduled to take effect in 2008.

EXECUTIVE SUMMARY

Dr. Kenneth Gordon

Special Consultant – National Economic Research Associates, Inc. (NERA)

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I am an economist and former Chairman of the Maine Public Utilities Commission and Massachusetts Department of Public Utilities. My testimony provides a discussion of the cost drivers that are leading to increased numbers of utility base rate proceedings in the U.S., with an emphasis on policy tools, including fuel adjustment clauses ("FACs") and related mechanisms, which can be used to reduce the frequency between rate cases, while both affording the utility a more consistent opportunity to earn its allowed returns and preserving or enhancing its incentive to seek efficiencies.

The utility industry in the U.S. is facing cost pressures such that rate case filings nationwide are back to the levels found in the early 1990s. In recent times, a new construction cycle has begun for generation, there is a need for transmission and distribution investment, and there are other investment requirements, such as investment in environmental controls. The widespread need for investment, coupled with an historically unprecedented rise in cost pressures related to both operating inputs (including fuel) and capital cost (infrastructure) items, makes it critical to ensure utility shareholders a reasonable return on investment.

Cost/revenue pressures make it more difficult, even for an efficiently-operating utility, to have a realistic opportunity to earn its allowed return. This necessitates more frequent rate cases. Regulatory lag gives a utility the incentive to control costs that are under a utility's control between rate cases, but pressures from generally unavoidable costs can lead to attrition—the erosion in a utility's opportunity to earn its allowed return.

It is thus very important to treat utility shareholders fairly by allowing more immediate and certain recovery of hard to predict and/or volatile costs (such as fuel costs) that lie outside the control of utility management. Fuel cost riders, such as fuel adjustment clause mechanisms, are a means to alleviate attrition and the pressure imposed by frequent rate case filings, while protecting the financial stability of the utility. Fuel adjustment clauses are used almost universally to regulate vertically integrated electric utilities throughout the country in non-restructured jurisdictions.

Utilities and regulators throughout the country face challenges due to higher day-to-day operating costs and very large investment requirements. In this context, searching for the best balance between regulatory lag for controllable costs and more timely cost recovery for uncontrollable costs, such as fuel costs, is not only useful, but is critical to achieving good quality service at reasonable rates over the long term. This can best be done by finding and implementing ratemaking best practices, including the use of fuel adjustment clauses where appropriate.

EXECUTIVE SUMMARY

Gary S. Weiss

Manager of Regulatory Accounting for Ameren Services Company

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The purpose of my testimony is to present the Company's revenue requirement recommendation for its Missouri jurisdictional electric operations. Based on the Company's revenue requirement, a $250,806,000 rate increase under traditional ratemaking is justified.

The Company's revenue requirement is based on a test year consisting of the twelve months ended March 31, 2008, utilizing nine months of actual and three months of forecasted information. The Company has proposed certain adjustments to update the test year for known and measurable changes through June 30, 2008. The Company is also proposing to true-up plant in service, depreciation reserve, accumulated deferred income taxes, customer growth in revenues, actual fuel prices, wage increase and new employee levels, and depreciation expense through September 30, 2008. The three months of forecasted information will be updated with actual data as the data becomes available, including audited financial data which can be utilized to update the test year through June 30, 2008. This data will be provided to all parties on or before July 31, 2008. The Company's rate base has been updated through June 30, 2008 to reflect all anticipated additions to plant in service. The billed revenues and kWh sales have been adjusted to reflect normal weather and customer growth through June 30, 2008. The off-system sales revenues have been adjusted to reflect a normal level of off-system sales priced at normal market prices. The production expenses reflect the current known and measurable coal and transportation contract prices along with normalized plant generation and load requirements (see the direct testimony of Company witnesses Shawn E. Schukar, Robert K. Neff and Timothy D. Finnell). The remaining operating expenses have been adjusted to reflect: (a) 2008 wage and salary increases, (b) elimination of the incentive compensation applicable to the Ameren Services and AmerenUE officers, (c) annualized year 2008 major medical and other employee benefits, (d) the amortization of the regulatory liabilities due to the pension and other post-employment benefits trackers, (e) a reduction to reflect only two-thirds of the Callaway refueling expenses other than replacement power, (f) elimination of all expenses related to the Taum Sauk reservoir failure and clean-up, (g) increases in tree trimming expense to include costs associated with the Company's compliance with the vegetation management rules, (h) an annualized amount for various reliability and inspection programs necessary to reflect the cost of meeting the mandated infrastructure rule standards, (i) the current level of charges by the Midwest Independent Transmission System Operator, Inc. ("MISO"), (j) various adjustments required to reflect the Report and Order in Case No. ER-2007-0002, and (k) the expenses required to prepare and litigate this rate increase filing.

The Company is not proposing any new depreciation rates in this case. The current approved depreciation rates have been applied to the depreciable plant balances at March 31, 2008 as well as to the additions to plant through June 30, 2008. The amortization expense has been increased to reflect amortization of the January 2007 ice storm expenses over 60 months beginning on the effective date of the new rates approved for this rate filing, per the Application for an Accounting Authority Order filed by the Company. Taxes other than income taxes have been adjusted to reflect the increase in F.I.C.A. tax related to the wage and salary increases, and real estate taxes have been reduced to exclude the taxes applicable to plant held for future use. Finally, the Company's revenue requirement is based on a 10.90%

return on common equity (see the direct testimony of Company witness Dr. Roger A. Morin). Reflecting the above items, the Company's Missouri jurisdictional revenue requirement is $2,871,465,000. This revenue requirement is $250,806,000 greater than the Company's current operating revenues.

Net base fuel costs are determining by calculating the sum of (a) the fuel and purchased power costs determined from the production cost modeling performed by Mr. Finnell, as discussed in Mr. Finnell's direct testimony plus (b) certain additional fuel and purchased power cost components, and then reducing that sum by off-system sales revenues calculated by Mr. Finnell's production cost modeling plus adjustments to include MISO Day 2 revenues and capacity sales. That difference was then divided by the normalized AmerenUE load to arrive at the net base fuel costs on a per kWh basis of 0.837 cents.

The Company has been unable to earn the return on equity authorized by the Commission since its last rate case. For the nine months of June 2007 through February 2008, the Company's earned return on equity has consistently been below its authorized return on equity of 10.2 percent. During that period, the Company's average earned return on equity was just 9.09 percent, or 111 basis points below that authorized by the Commission. In fact, in only one of those seven months was the Company's return on equity within even 50 basis points of its authorized return on equity.

In the Report and Order in Case No. ER-2007-0002, the Commission established an accounting mechanism to track AmerenUE's future sulfur dioxide ("SO_2") net revenue (SO_2 premiums, net of discounts, and SO_2 allowance sales). Additionally, Attachment C to the Stipulation and Agreement As To Certain Issues/Items in Case No. ER-2007-0002 established a tracker for pension and other post-employment benefits expenses. My testimony explains the operation of these trackers and their impact on the revenue requirement in this case.

The proposed revenue requirement in this case includes an annualized level of costs related to the Commission's new vegetation and infrastructure rules. However, the costs that the Company incurs between January 1, 2008 and the date that the rates set in this proceeding take effect are not reflected in the Company's revenue requirement. In addition, any incremental costs that the Company may incur in future years, due for example to inflation, are not reflected in the Company's proposed revenue requirement. I am requesting that the Commission grant the Company accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from the Company's next general rate case. In accordance with the vegetation management and infrastructure rules, the Company will use a tracking mechanism to record the difference between the expenses actually incurred as a result of the rules and the amount included in the Company's rates. Recovery of these expenses can be addressed in the Company's next rate case.

Executive Summary

Martin J. Lyons, Jr.

Senior Vice President and Chief Accounting Officer

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The purpose of my testimony is to sponsor the Company's proposed fuel adjustment clause ("FAC") and explain why the Commission should approve AmerenUE's request for an FAC. AmerenUE's proposed FAC is attached to my testimony as Schedule MJL-E1.

The proposed FAC applies to AmerenUE's total fuel, transportation, and purchased power costs, net of off-system sales revenues (i.e., the Company's "net fuel costs"). The proposed FAC captures 95% of the deviations between actual net fuel costs and net base fuel costs (i.e., net fuel costs included in base rates) through three annual FAC rate adjustments and provide for recovery over 12-month recovery periods. The net base fuel costs will be set in this rate case to reflect a normalized level of fuel, transportation and purchased power costs, net of off-system sales revenues. As set out in Schedule MJL-E4, AmerenUE has also complied with the Commission's minimum filing requirements for an FAC application, as provided for in 4 CSR 240-3.161(2).

The proposed FAC is needed to address the combination of significant increases in AmerenUE's fuel costs and substantial volatility and uncertainty of net fuel costs, which adversely affect the Company's financial strength and prevent the Company from having an ability to have a sufficient opportunity to earn a fair return. Moreover, an FAC is needed to maintain the Company's overall financial health and to allow it to effectively compete for the very large amounts of capital it needs, particularly given that nearly all similarly situated utilities are already able to utilize FACs.

AmerenUE's fuel costs are large, volatile, and almost entirely beyond the control of AmerenUE. Total AmerenUE fuel and purchased power costs for the test year exceed $810. Test year off-system sales revenues are approximately $466 million. Those off-system sales revenues are netted against fuel costs in the proposed FAC resulting in net base fuel costs of approximately $344 million. See Schedule MJL-E2.

Both fuel costs and off-system sales are subject to significant uncertainties that have a large impact on the Company's finances, including its ability to earn a fair return and to compete for capital. For example, the increases in coal costs over the next two years alone taking into account AmerenUE's substantially hedged position amount to almost **[redacted]** million (from **[redacted]** million in the test year to **[redacted]** million in 2010). An increase of that size would depress AmerenUE earnings by approximately **[redacted]** basis points, unless offset or recovered in rates. Natural gas and nuclear fuel costs are also increasing. These fuel cost increases are discussed in detail in the direct testimonies of AmerenUE witnesses Robert K. Neff (delivered coal costs), Scott A. Glaeser (gas costs) and Randall J. Irwin (nuclear fuel costs).

Traditional ratemaking will not permit AmerenUE to timely recover these fuel cost increases. Because the Commission relies on an historic test year, even if a rate case was timed perfectly the Company would have to absorb 17 – 18 months of the 2009 cost increases and 5 - 6 months of the 2010 cost increases before rates reflecting them could take effect. To time a rate case to include the 2010 coal cost increases, for example, would require the filing of a new rate case in July of 2009 – essentially immediately after the conclusion of this rate case – and the Company would still under-recover our fuel costs by approximately **[redacted]** million in 2010

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alone by the time new rates could take effect. This would result in a 2010 earnings deficiency of approximately **[redacted]** million (more than **[redacted]** basis points of return on equity), which is more than a 12% reduction in 2010 earnings caused by fuel cost increases alone.

Future off-system sales revenues could be higher or lower than the normalized amount that the Commission sets in this rate case and we would certainly hope that any increases in off-system sales margins would at least partially offset fuel cost increases if the Commission did not approve our FAC. However, while we can hope for such a result, it cannot be expected to occur. The significant fuel cost increases facing AmerenUE, and other cost items that will very likely exacerbate these fuel cost increases, mean the Company will not have a sufficient opportunity to earn the fair rate of return that the Commission will authorize in this case without an FAC.

There is also a substantial amount of volatility and uncertainty in the un-hedged portions of the Company's net fuel costs. As shown in the direct testimony of AmerenUE witness Ajay K. Arora, despite AmerenUE's substantial efforts to hedge the underlying cost of fuel commodities and its off-system sales where practical and cost-effective to do so, the remaining un-hedged portion of these costs exposes the Company to large operating margin uncertainties.

For example, according to Mr. Arora's analysis, there is a 50% chance that the Company's net fuel costs will be less than **[redacted]** million or more than **[redacted]** million (a **[redacted]** million swing) in 2009. A **[redacted]** million uncertainty range represents a potential swing in AmerenUE's earnings of approximately **[redacted]** basis points. Mr. Arora's test year analysis shows that even at the beginning of a year when essentially all of AmerenUE's fuel costs and a portion of its off-system sales are hedged, significant uncertainty remains. There is (1) a 50% chance that the uncertainty in annual net fuel costs (i.e. the range between the 25th and the 75th percentiles) will be more than **[redacted]** million in that year, and (2) a 20% chance that

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the uncertainty in net fuel costs will exceed **[redacted]** million in that year (i.e., representing the difference between the 10^{th} and 90^{th} percentiles). Of course, we do not know at what cost we will be able to hedge fuel between now and the beginning of any future year.

AmerenUE's FAC would accurately reflect in rates AmerenUE's actual net fuel costs (wherever those net fuel costs may fall within this range of uncertain outcomes) by allowing the Company to recover 95% of net fuel cost changes above the expected level, or allowing customers to benefit from 95% of net fuel cost changes below the expected level.

Fuel cost increases are not the only cost increases being faced by AmerenUE. The combination of already known and projected fuel cost increases, other operating cost increases, and large capital investment requirements to finance necessary infrastructure, including higher depreciation and interest costs associated with those capital investments, substantially increases the financial pressure on AmerenUE.

While AmerenUE is able to very substantially reduce net fuel costs for customers,[1] this large reduction carries with it the volatility and uncertainty inherent in the power markets, much like the volatility and uncertainty experienced by utilities with a heavy reliance on purchased power to meet their load obligations.

The vast majority of utilities with which AmerenUE has to compete in capital markets are able to operate with the benefit of an FAC. Of the 94 utilities in other non-restructured states[2], 85 (90%) already operate under an FAC, and 5 more utilities have an FAC application currently pending before their respective state regulatory commissions. This prevalence of FACs is even more pronounced on a regional basis. Indeed, 36 of the 37 (97%) utilities in the surrounding

[1] The reduction is approximately 58% based upon normalized test year fuel and purchased power costs and off-system sales revenues.

[2] My references to "non-restructured" states includes 29 states (other than Missouri) that have not restructured their utility industries, as well as an additional 5 states with vertically integrated utilities that have now suspended restructuring.

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non-restructured Midwestern states already operate under an FAC, including virtually all utilities with a heavy reliance on coal-fired generation. That FACs are equally prevalent for coal-intensive utilities such as AmerenUE is evidenced by the fact that of 27 coal-intensive utilities in the surrounding non-restructured Midwestern states, 26 (96%) have a FAC.

In short, the proposed FAC is necessary to enable AmerenUE to timely recover the substantial fuel cost increases the Company is facing in the next several years, compete for the capital needed for investments the Company must make on more favorable terms, and address and manage the volatility and uncertainty of net fuel costs and their effect on the Company's ability to have a sufficient opportunity to earn a fair return, particularly in the face of the rapidly increasing costs to which AmerenUE, along with the rest of the industry, is exposed today.

EXECUTIVE SUMMARY

Robert K. Neff

Vice President of Coal Supply for Ameren Energy Fuels and Services Company

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The purpose of my testimony is to explain how coal was bought and delivered in the test year, describe the increases in delivered coal costs in the test year ending March 31, 2008 updated through June 30, 2008, compare the updated test year delivered coal costs to the costs in Company's prior rate case, discuss coal market price trends, and discuss the nature and uncertainty of future coal cost increases.

Delivered coal costs in the updated test year ending June 30, 2008 are expected to be \$1.48 per million British thermal unit ("MMBtu"), an increase of 12% over the delivered coal costs of \$1.32/MMBtu established as the level of delivered coal costs in the prior AmerenUE rate case, which was concluded in May, 2007. At a normalized use of 392,247,000 MMBtu, this is an annual coal cost increase of \$61,975,000 over the costs included in the revenue requirement established in the prior AmerenUE rate case.

The coal and transportation markets, like all fuel markets, have been extremely volatile. As an example, the spot price of 8800 Powder River Basin coal went from \$11.20 on November 1, 2007 to \$17.00 on February 29, 2008, an increase of 52% in just four months. While the Company's hedging program dampens the volatility of fuel prices in the year in which the fuel is consumed, the Company is exposed to substantial unhedged fuel cost increases in the future. Approximately 49% of the Company's exposure to the coal and transportation markets are unhedged over the 2009-2012 time period.

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Based on fluctuations in the fuel and transportation markets, the range of the Company's possible exposure to fuel price changes were calculated. The annual possible range of fuel costs in years 2009 through 2012, where fuel is less hedged, are projected to be from $**[redacted]** below to $**[redacted]** above the expected 2008 delivered coal cost of $585,864,000.

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EXECUTIVE SUMMARY

Scott A. Glaeser

Vice President Gas Supply and System Control for AmerenEnergy Fuels and Services Company

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The purpose of my testimony is to address three areas regarding the procurement of gas supply to fuel the Company's gas generation plants: 1) price volatility and uncertainty of the natural gas market, 2) volatility of gas generation demand, and 3) the expected range of future gas generation fuel costs.

My testimony describes the volatility of the natural gas markets in the U.S. and the factors driving that volatility. The fundamental factor is the decline of domestic gas production from maturing basins while demand has continued to grow, primarily from gas-fired electric generation, creating a precarious balance between supply and demand. When this precarious balance is upset due to events such as hurricanes in the Gulf of Mexico ("GOM") or high crude oil prices, the gas market can react violently with price spikes and daily volatility. New sources of gas supply such as non-conventional production, deepwater GOM, and Liquefied Natural Gas are coming on-line, but these new resources are more expensive, volatile, and subject to global influences. I testify that the volatility and uncertainty of gas prices are well beyond the control of AmerenUE management. Finally, I describe the Company's gas price forecast for 2008 through 2012 including our range of probable gas prices, which spans from a low scenario of $**[redacted]** per MMBtu in 2012 to a high scenario of $**[redacted]** per MMBtu in 2008.

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I then describe the volatility and uncertainty of gas generation demand due to the functions gas generation provides for AmerenUE including serving peak load periods, as a generation capacity backstop for coal and nuclear outages, and for off-system power sales and MISO dispatches for control area reliability. I developed a range of expected gas generation demand for 2009 through 2012 based upon historical data with a low scenario demand of **[redacted]** MMBtu in 2009 and a high scenario demand of **[redacted]** MMBtu in 2012.

In summary, I develop an expected range of total fuel costs for 2009 through 2012 from our expected range of gas generation demand and future gas prices. The range of fuel costs can vary from a low of $**[redacted]** in 2009 to a high of $**[redacted]** in 2012. This illustrates that gas generation fuel costs are volatile, highly uncertain, and beyond the control of management, with potential swings in excess of $150,000,000 from year to year.

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EXECUTIVE SUMMARY

Randall J. Irwin

Supervising Engineer, Fuel Cycle Management for AmerenUE

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The purpose of my direct testimony is to discuss nuclear fuel costs for the Callaway Plant. In particular, I: a) present the nuclear fuel cost for the test year, April 1, 2007 to March 31, 2008, b) provide an historical perspective on actual nuclear fuel costs for Callaway, c) discuss recent changes in the nuclear fuel markets, d) provide expected nuclear fuel costs going forward, and e) discuss volatility in the nuclear fuel market and how it can impact future nuclear fuel costs for the Callaway Plant.

The total nuclear fuel cost for the 12 month period April 1, 2007 to March 31, 2008 is $47.3 million. Nuclear fuel costs are based on the amortization of the initial costs of the 193 fuel assemblies contained in the Callaway reactor. In addition, fees required to be paid to the Department of Energy ("DOE") for both spent fuel disposal and decommissioning and dismantling ("D&D") of certain DOE facilities are included. The fuel cost of $47.3 million represents the amortization of the fuel assemblies during the 12 month period beginning April 1, 2007 and the DOE fees incurred during that time.

Nuclear fuel costs for Callaway have changed over the past few years. The changes are provided in Tables 1 and 2.

Table 1

Year	Fuel Cost $ millions	Fuel Cost $/MWHr	Generation MMWHr
2004	35.3	4.48	7.874
2005	35.3	4.39	8.045
2006	45.8	4.53	10.110
2007	45.9	4.89	9.38

Table 2

Reload Date (Year – Month)	04 - May	05 - Nov	07 - May
Total Reload Cost ($M)	46.2	51.4	67.9
Avg. Uranium Cost ($/lb.)	17.4	18.6	25.3
Avg. Enrichment Cost ($/SWU)	94.1	111.5	121.5

The nuclear fuel markets have experienced years of depressed prices, with little or no expansion of production facilities. Uranium is a prime example. From 1994 to 2004, the price of uranium never exceeded $20/lb. Inventories were being drawn down, with little production expansion. Worldwide demand for uranium has begun to increase, and is expected to continue to increase for several years. Significant global growth in nuclear power is occurring in such countries as China, Russia and India. Today's uranium prices of $80-90/lb. are sufficient to support investment in new production. Production is expanding, but is still unable to keep up with demand. Upward pressure on uranium pricing will remain for the foreseeable future. Production problems have occurred, and will continue. With limited supplies of uranium and demand increasing, price volatility is the expected norm. Although current spot prices are approximately $80/lb., prices have been as high as $136/lb. The enrichment services market is another example. Demand for enrichment is increasing, just like demand for uranium. Building new enrichment facilities is a highly technical, very proprietary, and expensive venture. Enrichment costs in the range of $150-160/SWU are necessary to support the expansion of this critical portion of the industry.

During the four year period following the test year, the Company's total nuclear fuel costs, and costs of reloads, are expected to be as follows:

Table 3

Year	Fuel Cost $ millions	Fuel Cost $/MWHr
2009	**[redacted]**	**[redacted]**
2010	**[redacted]**	**[redacted]**
2011	**[redacted]**	**[redacted]**
2012	**[redacted]**	**[redacted]**

Table 4

Reload Date (Year – Month)	08 - Nov	10 - Apr	11 – Oct
Total Reload Cost ($M)	**[redacted]**	**[redacted]**	**[redacted]**
Avg. Uranium Cost ($/lb.)	**[redacted]**	**[redacted]**	**[redacted]**
Avg. Enrichment Cost ($/SWU)	**[redacted]**	**[redacted]**	**[redacted]**

Of the two components, uranium and enrichment services, the uranium component exposes AmerenUE fuel costs to the most volatility. Unlike the period 2004 - 2007 where uranium and enrichment each comprised about 30% of total nuclear fuel costs, the contribution of uranium has increased. During the period 2009 - 2012, uranium is now forecast to comprise approximately 50% of total fuel costs. Enrichment costs will represent less than 30% of total fuel costs. In addition, the contracts for uranium supplies in the **[redacted]**. The uranium market is the one nuclear fuel market that has exhibited, and is expected to continue to exhibit, the most volatility. In 2007 alone, spot uranium prices went from $75/lb. in January, peaked at $136/lb. in June,

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and ended the year at $90/lb. The potential impact of uranium price volatility on nuclear fuel costs is presented in Table 5.

Table 5

Annual Fuel Costs ($ million)

Price Forecast	2009	2010	2011	2012
Low	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
High	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
Variance (high-low)	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**

During the period 2009 – 2012, nuclear fuel costs are expected to not only increase, but also be subject to significant volatility in the marketplace. Fuel cost increases during this time may be as high as **[redacted]**, due to uranium prices alone. Unanticipated increases in the cost of other components, and escalation parameters, will only further exacerbate this concern.

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EXECUTIVE SUMMARY

Shawn E. Schukar

Vice President, Strategic Initiatives, Ameren Services Company

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The purpose of my testimony is to address four areas relating to off-system sales revenues: 1) a determination of the normalized level of off-system sales that is appropriate to utilize for the determination of the Company's revenue requirement; 2) an explanation of how the level of off-system sales is dependent on the Company's loads, generation availability, and market energy prices; 3) an explanation of why it is appropriate to determine off-system sales revenues through the use of the PROSYM production cost model, and 4) documenting the significant uncertainty in the level of off-system sales revenues.

The appropriate level of off-system sales revenues to utilize in the determination of AmerenUE's revenue requirement is $454.3 million per year, which includes $443.2 million per year of off-system energy sales, $7.6 million per year of capacity sales, and $3.5 million per year of ancillary services sales. The energy sales values were determined based on modeling of AmerenUE's weather normalized load, normalized generation unplanned outages, normalized gas and electricity prices, and including the Taum Sauk generation facility as if it remained in service. This is appropriate because it is necessary to align the normalized generation unplanned outages and weather normalized loads that are utilized in determining rates with the level of off-system sales revenues that are used as an offset to the Company's revenue requirement for purposes of setting rates. In addition, to ensure that the customer is not affected by the unavailability of the Taum Sauk generation facility, AmerenUE's costs and revenues were modeled as if the Taum Sauk Plant was available.

This includes an adjustment for capacity sales that could have reasonably been expected to have been made had the Taum Sauk generation facility been available during the test year. In addition, an adjustment to energy sales values was made for forward sales of capacity, energy, and ancillary services that have been made for 2008.

The PROSYM production cost model was used for the determination of the off-system sales energy revenues. The key inputs used in the PROSYM model were normalized hourly loads, unit operating characteristics, fuel and emission costs, variable operation and maintenance costs and hourly market prices. For dispatch purposes, the market prices for normalized off-system sales, consistent with the fuel and emissions costs, are monthly energy prices for the period from January 2006 through December 2007, which results in a normalized average energy price of $40.47. The use of this two-year weighted average, which is based on the locational marginal prices at the generators that had actually made off-system sales during 2007, is appropriate to ensure consistency with normalized loads and unplanned outages.

The level of off-system sales has a significant amount of uncertainty associated with: (1) native load variability (which reduces the amount of generation that is available for sales); (2) generation unplanned outage rates; and (3) market prices for power. Based on historical information associated with native load variability, native load variability can cause approximately $68 million in uncertainty of off-system sales revenues. Unplanned forced outages for the AmerenUE generating plants historically varied by 6%, from 5.6% and 11.6%. This 6% variability in the unplanned outages at AmerenUE generating plants creates uncertainty in AmerenUE off-system sales revenues of approximately $121 million. Finally, the uncertainty in spot and forward market prices for energy creates uncertainty in off-system sale revenues of up to $157 million.

EXECUTIVE SUMMARY

AJAY K. ARORA

Director of Corporate Planning

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The purpose of my testimony is to document the uncertainty of AmerenUE's net fuel costs which, in turn, provides support for one of the bases addressed by AmerenUE witness Martin J. Lyons, Jr. in his direct testimony relating to AmerenUE's request to implement a fuel adjustment clause ("FAC"). Net fuel costs are the Company's fuel, fuel transportation, and purchased power costs, net of off-system sales revenues.

I have first quantified the uncertainty in net fuel costs that the Company faced at the beginning of the test year, considering AmerenUE's typical "hedge ratios" at the beginning of a year. This documents that significant net fuel cost uncertainty remains even at the beginning of each year, despite the risk mitigation that is achieved by the Company's substantial hedging and long-term contracting efforts. I then also quantified the net fuel cost uncertainty that can be expected during the years 2009 through 2012, considering AmerenUE's hedged (or known) positions with respect to fuel, purchased power, and off-system sales as of February 2008. Even though more of AmerenUE's costs will be hedged at the beginning of each of these years, the uncertainties when looking forward from the time of the rate case are larger than those at the beginning of a particular year because we do not know at what cost we will be able to hedge fuel between now and the beginning of any particular future year.

I do not expect changes in AmerenUE off-system sales revenues to substantially offset AmerenUE's coal cost changes because of several operational and market realities. First, AmerenUE's coal-fired generating units are generally lower cost than many of the other coal-fired units within the footprint of the Midwest Independent Transmission System Operator, Inc. ("MISO"), as shown on Schedule AKA-E4. The market price of power in the MISO is set by the marginal (highest cost) generating unit, which means that power prices are related to the characteristics of that marginal unit, including its fuel type, heat rate, variable operating costs and other pertinent factors. For example, AmerenUE's coal-fired plants burn Power River Basin, Wyoming coal, and transportation costs are approximately **[redacted]** of AmerenUE's delivered coal costs. Even when coal plants determine the market price of power (e.g., mostly during off-peak periods) other coal plants in the MISO footprint that are more likely to be the marginal unit may burn a different type of coal (e.g., Illinois or Central Appalachian coal), may be exposed to higher incremental environmental allowance costs (e.g., for SO_2 or NO_x), and may face very different coal transportation options. Anticipated power market conditions may also change significantly over time (e.g., due to load growth, the addition or retirement of generation, new transmission lines, or new environmental investments), which may change power prices independently of any changes in coal prices whatsoever. Consequently, changes in AmerenUE's own coal costs cannot be expected to be offset significantly by corresponding changes in power prices.

Second, while AmerenUE can hedge its delivered coal costs from one to five years into the future (with a lower percentage of the costs hedged further into the future), the Company is not able to hedge its off-system sales at the same time it procures its coal. This is because the shape of AmerenUE's native load profile, which AmerenUE has an obligation to serve, results in AmerenUE's off-system sales profile being mismatched with standard market products available to hedge off-system sales. This mismatch, coupled with the illiquidity in the off-system sales markets several years out, does not allow AmerenUE to hedge its off-system sales the way it can

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hedge its exposure to coal markets. This means it is highly unlikely that changes in off-system sales revenues will offset any changes in AmerenUE's fuel costs.

I have conducted a detailed simulation analysis that confirms the foregoing discussion, and that also shows a high level of uncertainty and volatility in AmerenUE's net fuel costs. Specifically, I have used a probabilistic production cost model, RTSim, to estimate uncertainties in net fuel costs, which represent the *combined* uncertainty forecasts for power prices, native load and off-system sales quantities, plant outages, and the market prices for coal, natural gas, and nuclear fuel, considering AmerenUE's long-term contracting and hedging practices. The RTSim model also incorporates relevant operational data such as the use of spot natural gas prices rather than long-term natural gas prices and correlations between variables, such as temperatures and power prices.

For each uncertain variable, a statistical measure of the average annual dispersion around the base forecast for that variable was computed (which I refer to as the "annual uncertainty factor"). These uncertainties were then applied to "targets" (that is, the average anticipated values) for each of the uncertain variables. In addition, correlation measures of how the uncertainty in one variable is related to the uncertainty in other variables were estimated. The combination of these "targets" and uncertainty parameters, including correlations between key variables, is what results in an average level of annual net fuel costs and an uncertainty range around that average value.

Using these parameters, 250 scenarios of joint outcomes for the uncertain variables were developed that reflected the dispersion and the estimated correlations between the variables. RTSim was then run for each year to compute AmerenUE's net fuel cost for each of the 250 input scenarios. The dispersion of the 250 RTSim computations of AmerenUE's net fuel cost demonstrates the uncertainty in AmerenUE's annual net fuel costs.

The results of this simulation analysis demonstrate that there exists substantial uncertainty and volatility in AmerenUE's net fuel costs. For example, the modeling indicates that even under the substantially hedged positions the Company typically has at the beginning of a particular year, there is (1) a 50% chance that the uncertainty range in net fuel costs (i.e., the range between the 25th percentile and the 75th percentile of the distribution of possible net fuel costs) is more than $**[redacted]** million a year; and (2) a 20% chance that the uncertainty range in net fuel costs exceeds $**[redacted]** million a year (i.e., representing the difference between the 10th and 90th percentile of the distribution of possible net fuel costs).

Although these potential swings in annual net fuel costs are quite large, even when substantial fuel cost hedges are in place at the beginning of a year, the uncertainty range of annual net fuel costs is even larger for future years that are not as extensively hedged at this point. For example, in 2009 there is a 50% chance that the Company's net fuel costs will be less than $**[redacted]** million or more than $**[redacted]** million. In other words, there is a 50% chance that the uncertainty range *exceeds* $**[redacted]** million. In fact, there is a 20% chance that the uncertainty range (i.e., the range between the 10th and 90th percentile) exceeds $**[redacted]** million in 2009.

Finally, the simulation analysis confirms my opinion about the lack of an off-system sales revenue offset against AmerenUE's fuel cost increases. For example, for the entire study period, test year to 2012, the target net fuel costs increased by $**[redacted]** million while target revenues from off-system sales increased just $**[redacted]** million, resulting in an overall increase in net fuel costs of $**[redacted]** million.

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EXECUTIVE SUMMARY

Timothy D. Finnell

Managing Supervisor, Operations Analysis in the Corporate Planning Function of Ameren Services Company

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The purpose of my testimony is to explain the production cost model used to determine the normalized net fuel costs which consists of fuel costs, the variable component of purchased power costs and off-system sales revenues for this case. I also supply the supply and demand side resources that are expected to serve AmerenUE's load during the four true-up years when the Company's requested fuel adjustment clause would be in effect.

A production cost model is a computer application used to simulate an electric utility's generation system and load obligations. One of the primary uses of a production cost model is to develop production cost estimates used for planning and decision-making. The program I used for my analysis is PROSYM. AmerenUE's experience with this program indicates that it does a superior job of simulating complex generating systems such as AmerenUE's system.

PROSYM utilizes monthly energy with a historic hourly load pattern. The monthly energy reflects AmerenUE kilowatt-hour ("kWh") sales and line losses. The fuel expenses used include the nuclear, coal, oil, and natural gas costs associated with producing electricity from the AmerenUE generation fleet. For purposes of this model, it was presumed that AmerenUE's Taum Sauk plant was available as a generation resource for the entire year. The model also considers normalized hourly loads, unit availabilities, fuel prices, unit operating characteristics, hourly energy market prices, and system requirements.

The normalized net fuel costs for this case are $290 million, which consists of fuel costs of $678 million, variable purchase power costs of $55 million, offset by off-system sales revenues of $443 million. These results are utilized by AmerenUE witness Gary S. Weiss in developing the revenue requirement for AmerenUE.

EXECUTIVE SUMMARY

Paul W. Mertens

Assistant Manager of Fuel Planning for Ameren Energy Fuels and Services Company

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The purpose of my testimony is to address certain minimum filing requirements ("MFRs") provided for in the Commission's Fuel Adjustment Clause ("FAC") rules, specifically, in 4 CSR 240-3.161(2)(F) through (I). Information on all of the FAC minimum filing requirements, including those addressed in my testimony, is also found in Schedule MJL-E4 to the direct testimony of AmerenUE witness Martin J. Lyons, Jr.

With respect to MFR (F), I explain the true-up calculation that will occur after the end of each true-up year.

With respect to MFR (G), I describe how AmerenUE's proposed FAC is compatible with the requirement for prudence reviews. This includes a clear delineation of costs provided for in the FAC tariff, detailed monthly reporting of data that will be useful in the prudence review process, and the availability of other information that can be used in the prudence review process.

My testimony regarding MFR (H) provides a detailed explanation of all of the costs that will be considered for recovery under the proposed FAC, including a detailed description of coal commodity costs, coal transportation costs, fuel oil costs, natural gas costs, water for power expenses, nuclear fuel costs, and purchased power costs. Included in my testimony is a detailed table that specifies these costs, by account.

The last MFR addressed in my testimony is MFR (I), which requires a complete explanation of all revenues considered in determining the amount eligible for recovery under the proposed FAC. My testimony includes a table specifying these revenues (such as off-system sales and coal sales) by account.

EXECUTIVE SUMMARY

Mark C. Birk

Vice President of Power Operations for AmerenUE

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The purpose of my testimony is to address 4 CSR 240-3.161(2)(P), which is a minimum filing requirement in the Commission's fuel adjustment clause ("FAC") rules. Requirement (P) requires a schedule and testing plan with written procedures for heat rate and/or efficiency tests for the utility's generating units. A unit's heat rate is a measure of its relative efficiency, expressed mathematically as the number of British thermal units ("Btus") a unit consumes to generate a kilowatt-hour ("kWh") of electricity. For example, a unit that consumes approximately 9,300 Btus of fuel to generate a kWh of electricity has a heat rate of 9,300 and is more efficient (consumes less fuel per kWh produced) than, for example, a unit with a heat rate of 10,000.

By monitoring heat rates, the Company can track the efficiency of its units and address observed reductions in a unit's efficiency appropriately. This, in turn, allows the Company to make efficient use of the fuel it buys by getting as much electric generation as it reasonably can from each unit of fuel burned.

With very limited exceptions for older combustion turbine units ("CTGs") that are run very infrequently each year, AmerenUE uses real-time performance monitoring systems on its generating units. Before such systems were in place, AmerenUE would have to conduct a heat rate test during some limited, defined period (typically four hours) to get the heat rate for that four hour period. By contrast, performance monitoring systems allow AmerenUE to continuously track and record generator output, heat rates, and controllable parameters. Plant operators use this real time performance information to continuously optimize the heat rates of the AmerenUE fossil units by making the necessary operational adjustments. This information also allows AmerenUE to use data from a much longer and more representative time period to establish a baseline heat rate for each unit, which in turn allows the Company to track the efficiency of the units.

Testing will be done annually. In general, the baseline heat rate test data will be done in December for the nuclear and coal-fired units, and in August for the CTGs. If the unit is out of service or there was not enough run time in those months, data from an earlier month may be substituted. However, this period will not be used for the CTGs because of the limited amount of generation during December. Since CTG generation typically occurs during the summer time period, the summer month of August was selected as the appropriate baseline period for CTGs. Another important fact to consider is that real time heat rates typically vary throughout the year based upon ambient conditions, thus a 12 month heat rate testing interval will be used to avoid comparisons of heat rates between cooler and warmer months.

EXECUTIVE SUMMARY

Dr. Roger A. Morin

Emeritus Professor of Finance at the Robinson College of Business in Atlanta, Georgia

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To arrive at my final return on equity ("ROE") recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term Treasury bonds. I also performed DCF analyses on two surrogates for UE's electric utility business: a group of investment-grade vertically integrated electric utilities, and a group of companies that make up Moody's Electric Utility Index.

The central tendency of the results is 10.9% for the average risk utility, as indicated by the mean and midpoint results of 10.9%. I note that the various results are closely clustered around 10.9%.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others.

Rider FAC serves to reimburse UE for prudently-incurred fuel and purchased energy expenses in a manner that minimizes the negative financial effects caused by regulatory lag.

Consideration of these energy expenses in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility. Rider FAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element that, in turn, would raise the Company's cost of capital. The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become the norm for regulated industries. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy. To wit, the vast majority of the companies that make up my comparable group possess such clauses.

My assessment of UE's business risk, hence of the Company's cost of common equity, is dependent on the adoption of the FAC. I believe that the absence of a FAC harms UE's financial condition, causes deterioration in its credit metrics (and thus puts downward pressure on its credit ratings), and puts its customers at risk of having to pay higher rates due to access to capital becoming more expensive for UE. Because of the magnitude of the energy cost component in its cost of service, these effects could be significant. I note that the Company's bonds are already under review for possible downgrade by Moody's and under "negative outlook" by Fitch.

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of UE's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms within a particular jurisdiction.

I very strongly encourage the Commission to approve UE's request for implementation of FAC, as it is fair to UE, its customers, and investors. I believe that the FAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis.

If the proposed Rider FAC were not approved, with no provision for recovery of on-going fuel and purchased power costs, the resulting increase in UE's cost of common equity would be substantive, at least 25 basis points in my view. Given the proportion of fuel and purchased power costs as compared to total revenue requirement in this proceeding, the Company faces higher financing costs for incremental financing and would be expected to be at substantial risk for material financial deterioration. The absence of an energy cost recovery mechanism subjects the Company to significantly increased risks, and thus a significantly higher cost of common equity, than it would incur under the timely application of Rider FAC. Only if an alternative mechanism to Rider FAC were approved that allowed for timely recovery of on-going fuel and purchased power costs, with carrying charges equal to the Company's overall required rate of return, would there be no impact on the cost of common equity.

My recommended return is predicated on the assumption that the Commission will approve the Company's proposed FAC, thus avoiding significantly increased risk to investors vis-à-vis the risk they face with an FAC. Absent this mechanism, the Company's risk with regard to volatile fuel prices is significantly enhanced versus operating with an FAC and the investor-required rate of return on common equity correspondingly significantly higher.

The risk associated with the absence of a fuel adjustment clause is further heightened by UE's reliance on coal-based generation because there are uncertainties with regard to new state and federal regulations to reduce the impact of greenhouse gas emissions. Such regulations are likely to increase power supply costs for companies with coal-based generation, such as UE, where coal is the primary fuel in 76% of the energy produced. UE is thus at a risk for potential environmental compliance cost increases. UE also faces additional risks because rates in Missouri are based on an historical rather than projected test year and because Missouri law prohibits the inclusion of construction work in progress ("CWIP") for electric plant in rates until the electric plant is in service.

The appropriate determination of UE's cost of equity should include a reasonable risk adjustment relative to the average utility to account for this additional risk. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier UE is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of 25 basis points and I have adjusted my result of 10.9% for the average risk utility upward to 11.15% in order to account for UE's higher relative risks. The risk adjustment was based on the difference in yield between utility long-term bonds rated Baa and A. The historical difference in yield is of the order of 20-40 basis points.

My recommended return on common equity for UE is predicated on the adoption of a test year capital structure consistent with the recommended capital structure for UE consisting of 51.12% common equity capital.

I examined the actual common equity ratios of my comparable group of companies. The average common equity ratio for the group is 48%, which is reasonably close to the Company's test year common equity ratio. The Company's slightly stronger capital structure partially offsets the Company's greater than average business risk, as discussed above.

A low authorized return on equity increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of UE, it is my opinion that a just and reasonable return on the common equity capital of UE's electric utility business at this time is 11.15% and 10.9% with the adoption of a fuel adjustment clause

Using RRA reported data for calendar year 2007, the average allowed ROE for integrated electric utilities was 10.56%. This means that the appropriate zone of reasonableness for the Commission to use in this case is 9.56% - 11.56%. My recommendations for an ROE for the Company, 10.9% if an FAC is approved, and 11.15% if an FAC is not approved, fall well within this zone of reasonableness.

EXECUTIVE SUMMARY

Michael G. O'Bryan

Senior Capital Markets Specialist in Corporate Finance for Ameren Services Company

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The table below outlines the various capital components of AmerenUE's capital structure along with the representative weights and costs of each as of December 31, 2007. The methodology for calculating both the amount and cost of long-term debt, short-term debt and preferred stock is detailed in Exhibits MGO-E2, MGO-E3 and MGO-E4, respectively. The Company's amount of common equity was based on the common shareholder's equity as of December 31, 2007 adjusted for miscellaneous items. The Company's cost of common equity, developed by the Company's witness Dr. Roger A. Morin, assumes the presence of a fuel adjustment clause.

CAPITAL COMPONENT	AMOUNT	PERCENT OF TOTAL	COST	WEIGHTED COST
Long-Term Debt	$2,981,873,369	45.536%	5.687%	2.590%
Short-Term Debt	$104,584,299	1.597%	3.621%	0.058%
Preferred Stock	$114,502,040	1.749%	5.189%	0.091%
Common Equity	$3,347,491,925	51.119%	10.900%	5.572%
TOTAL	**$6,548,451,633**	**100.000%**		**8.311%**

EXECUTIVE SUMMARY

Steven Wills

Managing Supervisor, Quantitative Analytics in the Corporate Planning Department for Ameren Services Company

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The purpose of my testimony is to introduce the methodology employed by AmerenUE ("Company") to weather normalize test year sales. Test year sales are used to develop billing determinants that are used to calculate new rates. Unusually warm or cool weather in a test year can cause the calculated rates to be set at a level that is likely to result in the Company either over-collecting or under-collecting its revenue requirement. Weather normalization is the process of determining the level of test year sales that will set a rate most likely to accurately collect the intended revenue requirement. Additionally, weather normalized sales are needed to perform production cost modeling and to develop variable cost allocation factors.

The process of weather normalizing sales includes developing statistical models that describe the relationship between customer class loads and weather in the test year, calculating normal weather variables to put into this statistical model, and calculating sales by billing month and calendar month based on the modeled results.

The inputs into the statistical model are hourly loads by customer class, daily two-day weighted mean temperature ("TDMT"), and the test year calendar. Hourly loads are obtained from the Company's load research program. TDMTs are calculated from temperature observations at St. Louis International Airport ("Lambert Field"). The purpose of calculating the TDMT is to introduce information about both the current day's and the prior day's temperatures into the model to help explain variation in load. The calendar input uses the actual calendar for the test year with seasons and days included in groups that have similar load characteristics. For example, weekends tend to have similar load patterns, so Saturdays and Sundays may be included in a group.

Once the inputs have been developed and the model has been executed in order to create the statistical relationship between weather and load, that relationship is used to adjust loads for the difference between the actual weather that occurred and normal weather. In order to do this, it is necessary to develop a normalized temperature for each day in the test year. Normal weather is based on temperatures realized over the years from 1971 - 2000. This time period is consistent with the definition of normal weather used by the National Oceanic and Atmospheric Administration ("NOAA") and by both the Company and the Missouri Public Service Commission Staff ("Staff") in recent cases. Historical temperature observations are adjusted to remove bias that has been introduced by changes in the temperature sensing equipment and location of the weather station. These adjustments are based on an agreement between the Company and the Staff first made in Case No. EM-96-149 that was relied upon again most recently by both parties in Case No. ER-2007-0002. The adjusted temperatures are run through a procedure called "rank and average." The rank and average procedure was used by the Company and Staff in Case No. ER-2007-0002. This procedure develops daily normal temperatures that will appropriately produce normal levels of load when run through the statistical models.

The statistical models of load and temperature are used in conjunction with the daily normal temperature data to develop daily normal loads for each rate class that is to be normalized. When this is complete, we have developed actual and normal daily loads. These two series of data are then used to adjust actual customer billing data from the test year to a normal level. The result of this process is normal loads for each billing month and calendar month within the test year.

At the time of preparing the initial case, the first nine months of the test year have been weather normalized. An update will be provided that will include the months of January through March of 2008. The period from April through December 2007 was generally warmer than normal. This was particularly true of August 2007, which was one of the warmest months on record in the Company's service territory. Based on this, the weather normalization analysis has resulted in reductions to test year sales in the summer months, as unusually warm temperatures resulted in increased air conditioning usage. The winter months were generally normalized by increasing test year sales to account for the higher level of space heating related electric sales that would be expected to occur in normal colder months.

EXECUTIVE SUMMARY

Wilbon L. Cooper

Manager of the Rate Engineering Department of AmerenUE

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My name is Wilbon L. Cooper and I am the Manager of the Rate Engineering Department of AmerenUE. The purpose of my testimony, and that of my associates, Mr. James R. Pozzo and Mr. William M. Warwick, is to address the following areas of the case:

Sales/Revenues

Class Cost of Service

Rate Design

Miscellaneous Tariff Revisions

Sales/Revenues - Sales, revenues and rate billing units, test year ending March 2008, as adjusted for customer growth through June 2008, were developed by Mr. Pozzo based upon the Company's weather normalized sales, and are provided in his schedules for use in the subsequent design of final rates as a part of this case.

Class Cost of Service – Mr. Warwick has performed a fully embedded class cost of service study that produced cost of service based revenue requirements at equal class rates of return for the test year ending March 2008. Included in this study was the use of the Average and Excess 4 NCP method for the allocation of fixed production costs. Generally, system peak demands and, to a major extent, excess customer demands, are the motivating factors which influence the amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate or peaking) which the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt-hours, which will be required to be generated by such capacity, i.e., the generation unit's utilization factor. The 4 NCP method gives proper weighting to both a) class peak demands and b) class energy consumption (average demands) which is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt-hours divided by total annual hours (8,760), and the excess NCP demands of each class. Additionally, Mr. Warwick's study further delineated the study results functionally among production, transmission and distribution and, also, classified the costs as either customer, energy, or demand related for the development of specific rates within the classes. The class revenue requirements from this study result in the following percentage increases for the Company's major customer classes: Residential 21%, Small General Service 6%, Large General Service/Small Primary Service 4%, Large Primary Service 14% and Large Transmission Service 5%.

Rate Design - While cost based rates are an important starting point in developing class revenue targets and rate design, there are other factors (e.g. public acceptance, rate stability, and revenue stability from year to year) that should be considered when determining class revenue requirements and designing rates. The Company's recently completed electric rate (Case No. ER-2007-0002) provided some insight on the consideration of other factors as many parties in the case signed and the Commission approved a nonunanamous Stipulation and Agreement Concerning Class Cost of Service and Certain Rate Design Issues ("Stipulation and Agreement"). This Stipulation and Agreement did not adopt any party's class cost of service results, but, rather contained a formulaic method to allocate any revenue decrease or increase to the Company's customer classes in that case. The Company is proposing to allocate the revenue increase requested in this case somewhat consistently with the Stipulation and Agreement. That is, the Company is proposing to allocate the requested revenue increase in this case on an across-the-board or equal percentage increase for all customer classes. This method results in a 12.1% percent increase to all customer classes.

Miscellaneous Tariff Revisions – Company witness Martin J. Lyons, Jr. is sponsoring the addition of a Fuel Adjustment Clause ("FAC") Rider to the Company's tariffs and, as a result, other tariff changes were necessary to accommodate revised FAC billing for the Company's respective customer classes. I am sponsoring these other FAC related changes along with several miscellaneous tariff revisions that are primarily of a housekeeping nature. These changes improve ease of customer understanding and administration and are of very limited application. Such proposed changes have no impact on the Company's base rate revenues.

EXECUTIVE SUMMARY

Michael Adams

Vice President - Concentric Energy Advisors

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My testimony discusses a lead-lag study for Union Electric Company d/b/a AmerenUE ("AmerenUE" or the "Company") performed by Concentric Energy Advisors under my supervision, which I used to develop cash working capital factors ("CWC factors"). The CWC factors are used by AmerenUE witness Gary S. Weiss to calculate the cash working capital requirements of the Company.

Cash working capital is the amount of funds required to finance the day-to-day operations of the Company, and should be included as part of AmerenUE's electric business rate base for rate making purposes. Cash working capital requirements are generally determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services, but pays for them at a later date. The results of the lead-lag study and the associated CWC factors are presented in Schedule MJA-E1.

EXECUTIVE SUMMARY

Edward C. Pfeiffer

Manager of the Electric Planning Department for Ameren Services Company

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The purpose of my testimony is to discuss AmerenUE's classification of its energy delivery facilities in accordance with the 7-Factor Test prescribed by the Federal Energy Regulatory Commission ("FERC") and to obtain a Commission determination confirming the Company's application of the 7-Factor Test to its energy delivery facilities. The Company is making this request solely to comply with a requirement in the Agreement of Transmission Facilities Owners to Organize the Midwest ISO (the "TO Agreement"), to which the Company is a party by virtue of its participation in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). Specifically, the TO Agreement requires the Company, as a "Transmission Owner" within the Midwest ISO, to obtain this determination from its state regulatory commission.

AmerenUE has classified its energy delivery systems in accordance with the FERC 7-Factor Test. AmerenUE has provided a list of its transmission facilities classified according to the FERC 7-Factor Test to the Midwest ISO, as required by the Midwest ISO TO Agreement. That list is identified in Appendix H of the TO Agreement, as required by Appendix H, and is also attached to my direct testimony as Schedule ECP-E1.