AMERENUE DIRECT TESTIMONY

EXECUTIVE SUMMARIES

MPSC CASE NO. ER-2007-0002

JULY 7, 2006

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EXECUTIVE SUMMARY

Warner L. Baxter

Executive Vice President and Chief Financial Officer
Ameren Corporation and AmerenUE

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The purpose of my testimony is to: (1) provide the Commission with an overview of the challenges facing the Company today, as well as the industry as a whole, many of which are the key drivers for the Company's rate increase request; (2) discuss how the Company has met such challenges in the past to the benefit of the Company, customers and the state, and address how we intend to meet these challenges in the future; (3) explain my view that an important component in meeting these challenges in the future is the continuing need for a constructive regulatory framework; (4) discuss what the key components of such a framework should include; (5) explain how our proposal in this rate case is consistent with a constructive regulatory framework; (6) provide my perspective on the rate increase request; and (7) summarize for the Commission the major areas of focus in this case and provide an overview of how we are addressing those issues in our filing.

This is the first rate increase AmerenUE has sought in two decades. The context of this rate proceeding provides an essential perspective by which to evaluate AmerenUE's 17.7%, or $361 million, rate increase request:

- In 2005, AmerenUE's average electric rates were approximately 30% below the national average, approximately 18% below the non-restructured states' average, and approximately 15% below the Midwest average, and were the lowest among investor-owned utilities in the state. See Schedule WLB-1.[1]

- St. Louis has the second lowest residential rates in the country compared to other major metropolitan areas surveyed by the Bureau of Labor Statistics. See Schedule WLB-2.

  Indeed, electric rates in St. Louis are lower than those in even small and mid-sized metropolitan areas, despite the higher costs associated with serving large metropolitan areas like St. Louis. See Schedule WLB-3.

- Since the Company's last rate case, AmerenUE's residential electric rates have ***decreased*** 6% while residential electric rates across the United States, in other non-restructured states, and in the Midwest ***have risen*** 11%, 13% and 5%, respectively. During that same period the prices of consumer goods and energy products in the region have risen dramatically.

- The trend of rising rates is continuing. Recent data from United States Department of Energy ("DOE") indicates that electric rates in the first quarter of 2006 are already 12% above their levels from a year ago.

- Approval of the Company's proposal in its entirety would still leave AmerenUE's electric rates 20% below the national average in 2007, as projected by the DOE. Moreover, when considering the electric rate increase requests submitted by every other Missouri investor-owned electric utility which are currently pending before the Commission, AmerenUE's rates would remain the lowest in the state. See Schedule WLB-7.

[1] For the Commission's convenience, copies of the Schedules noted are attached to this Executive Summary.

In recent years, customers have benefited from low rates, while the Company has benefited by posting solid financial performance that has allowed it to invest in infrastructure, maintain its credit ratings and keep borrowing costs low, have access to capital when needed at attractive rates, and deliver returns to investors consistent with the higher risks inherent in today's electric utility business.

This achievement is a direct result of the constructive regulatory framework that AmerenUE, the Commission and other stakeholders have crafted over the past decade or so that has allowed the Company to become more and more efficient, to reduce rates, to provide hundreds of millions of dollars of rate credits to customers, to invest billions of dollars in new infrastructure, and to maintain the financial health and flexibility needed to position the Company to meet the challenges it faced. This successful outcome has not only benefited customers, but has also supported the economic development of the State of Missouri, protected low-income customers, and provided numerous local jobs.

The Company must request this rate increase to address, among other things, a host of challenges it is facing, including:

1. Rising fuel costs, in particular the cost of coal, coal transportation, nuclear fuel and natural gas. For example, the Company's delivered cost of coal (our primary generation fuel) in 2007 will be 42% more than delivered coal costs when the Company's rates were last examined in 2002, with additional increases expected in future years;

2. Rising operating costs. For example, tree trimming expenses have risen more than 20%, and employee benefit costs, including medical costs for employees and retirees, have increased 56% since 2002;

3. Substantial increases in the cost of equipment and materials that are necessary to build and maintain a reliable electric generation, transmission, and distribution system. For example, since 2002, the cost of aluminum overhead wire has increased 93%, the cost of copper underground cable has increased 147%, and the prices of wood poles and transformers have jumped 34% and 57%, respectively;

4. A changing and volatile energy marketplace, which can result in significant variations in off-system sales margins and purchased power costs;

5. Rising interest rates, as evidenced by the Federal Reserve's 17 increases in interest rates over the past 24 months, with further increases possible;

6. The difficulty of maintaining and improving capacity and availability at aging power plants and in meeting the operational challenges posed by increasing environmental requirements;

7. The need to continue to make substantial infrastructure investments. Since our last rate case, AmerenUE has invested approximately $2.6 billion in its electric operations, including $700 million for 2,600 megawatts ("MW") of new generation to meet growing customer demands. The need for significant infrastructure investments in the future will continue, including an estimated $1.2 – 1.6 billion in environmental investments at AmerenUE plants over the next 10 years, additional maintenance and capital expenditure requirements to maintain plant capacity and reliability, additional transmission investments to meet the ever-increasing demands placed on the system, and within the foreseeable future, the need to add baseload generation to meet growing customer demands;

8. The desire for renewable sources of generation by many stakeholders;

9. Investor expectations of a higher return on their investments, driven in large part by the riskier environment in which electric utilities must operate today, which directly impact the cost and availability of capital; and

10. Political and regulatory uncertainty which also has a profound effect on returns demanded by investors and on credit ratings agencies' opinions of the quality of utility debt, both of which affect the availability and cost of the large sums of capital needed to run an electric utility business today.

In support of its case, the Company is presenting direct testimony from 26 witnesses on a variety of topics. Key aspects of the Company's proposal include:

- The appropriate recovery of costs and investments in utility plant based upon a test year for the 12 months ending June 30, 2006, updated for material known and measurable changes through January 1, 2007, including for known and measurable increases in coal and coal transportation prices effective January 1, 2007. Because, as of the date of this filing, the test year data includes three months of forecasted information, AmerenUE witnesses will file supplemental direct testimony, as necessary, on or before September 30, 2006 to include the results of the updated revenue requirement analysis using 12 months of actual test year data.
- A fair return on equity of 12%, as discussed in more detail in the direct testimony of AmerenUE witnesses Dr. James L. Vander Weide and Kathleen C. McShane, that reflects current capital market conditions for utility equity. As AmerenUE witness Lee R. Nickloy explains in his direct testimony, these capital market conditions justify an overall rate of return of 8.869%.

- To appropriately recover those costs and to achieve the required rate of return on its investments, the Company's revenue requirement analysis, as detailed in the direct testimony of AmerenUE witness Gary S. Weiss, reflects the necessity of an aggregate increase in revenues over those produced by existing rates of $360,709,000, a 17.67% increase over current rate levels.
- Although the requested increase is reasonable and not unexpected given the rising cost environment in which the Company is operating, the Company proposes to mitigate the impact of the rate increase on individual consumers by limiting the residential rate increase to no more than 10%, with all other rate classes to bear their proportionate share of the revenue required to produce the required revenue requirement increase, as discussed in the direct testimony of AmerenUE witness Wilbon L. Cooper.
- Because of changes in the electric industry including dispatch of the Company's generating units by the MISO, AmerenUE and Ameren Energy Generating Company ("AEG") have announced that the Joint Dispatch Agreement ("JDA") will terminate, by mutual consent, on December 31, 2006, subject to any necessary regulatory approvals. Consequently, the Company's revenue requirement analysis presented in connection with Mr. Weiss' direct testimony reflects that any excess AmerenUE energy is sold into the market as off-system sales at market prices rather than being transferred to AEG under the JDA at incremental cost.
- The Company's proposal, through the direct testimony of Company witnesses Michael L. Moehn and Professor Robert C. Downs, also discusses the Company's ownership of 40% of the shares of stock in Electric Energy, Inc., which were

purchased with shareholder funds and which have always been accounted for as a below-the-line item for ratemaking purposes. Moreover, the expiration of the AmerenUE's 400 MW cost-based contract with EEInc. is also addressed in our filing, including EEInc.'s decision to sell power at market rates, which as Company witness Professor Downs explains, was consistent with and indeed required by the fiduciary duties owed by the members of EEInc.'s Board of Directors to EEInc. and its shareholders.

- The Company's proposal reflects a normalized level of expected off-system sales margins ($180 million) as a credit to the revenue requirement. In addition, in order to address the risks inherent in establishing a normalized level of off-system sales margins under volatile energy market conditions, as well as provide a balanced incentive to control production costs and run our generating plants more efficiently, the Company has outlined an alternative off-system sales sharing mechanism, according to the following formula:

Level of Off-System Sales Margins (in millions of $)	Customer Share	AmerenUE Share	Effective Share for Customers
$0 - $120	100%	0%	100%
$121- $180	80%	20%	100% - 93%
$181 - $360	50%	50%	92% - 72%
Over $360	100%	0%	72% or more

From a regulatory policy perspective, this sharing mechanism provides a constructive regulatory framework in a number of important ways, including:

- It ensures that customers will always receive the lion's share of off-system sales margins earned by the Company under any scenario. Under this mechanism, ratepayers will never receive less than 72% of all of the off-system sales margins achieved by the Company, even should extraordinary off-system sales margins be achieved in the future due to, among other things, very strong energy prices;

- It provides customers with the opportunity to benefit from greater levels of off-system sales margins in excess of the amount of margins included that would be included in base rates under traditional regulation, which would otherwise go 100% to the utility. In the example I set forth above, customers would receive $8 million in credits to their rates greater than they would have received under traditional regulation based upon an appropriate level of normalized off-system sales margins ($180 million) should actual off-system sales margins in a given 12-month period equal $220 million;
- It addresses a significant uncertainty associated with determining the appropriate level of off-system sales margins to include in base rates by establishing a baseline target that is likely to be achieved under most circumstances, thereby mitigating the possibility that the baseline amount will not be achieved due to uncontrollable, volatile market conditions or uncertain operating conditions;
- It provides important, yet balanced incentives to the Company to improve its plant operations and lower its costs in a safe and reliable manner;
- The utility's sharing percentage in the grid never exceeds the benefits that customers will receive because no sharing band gives customers less than 50% of the margins within that band; and
- The off-system sales margins subject to sharing are capped at two times the appropriate normalized level of off-system sales established in base rates under

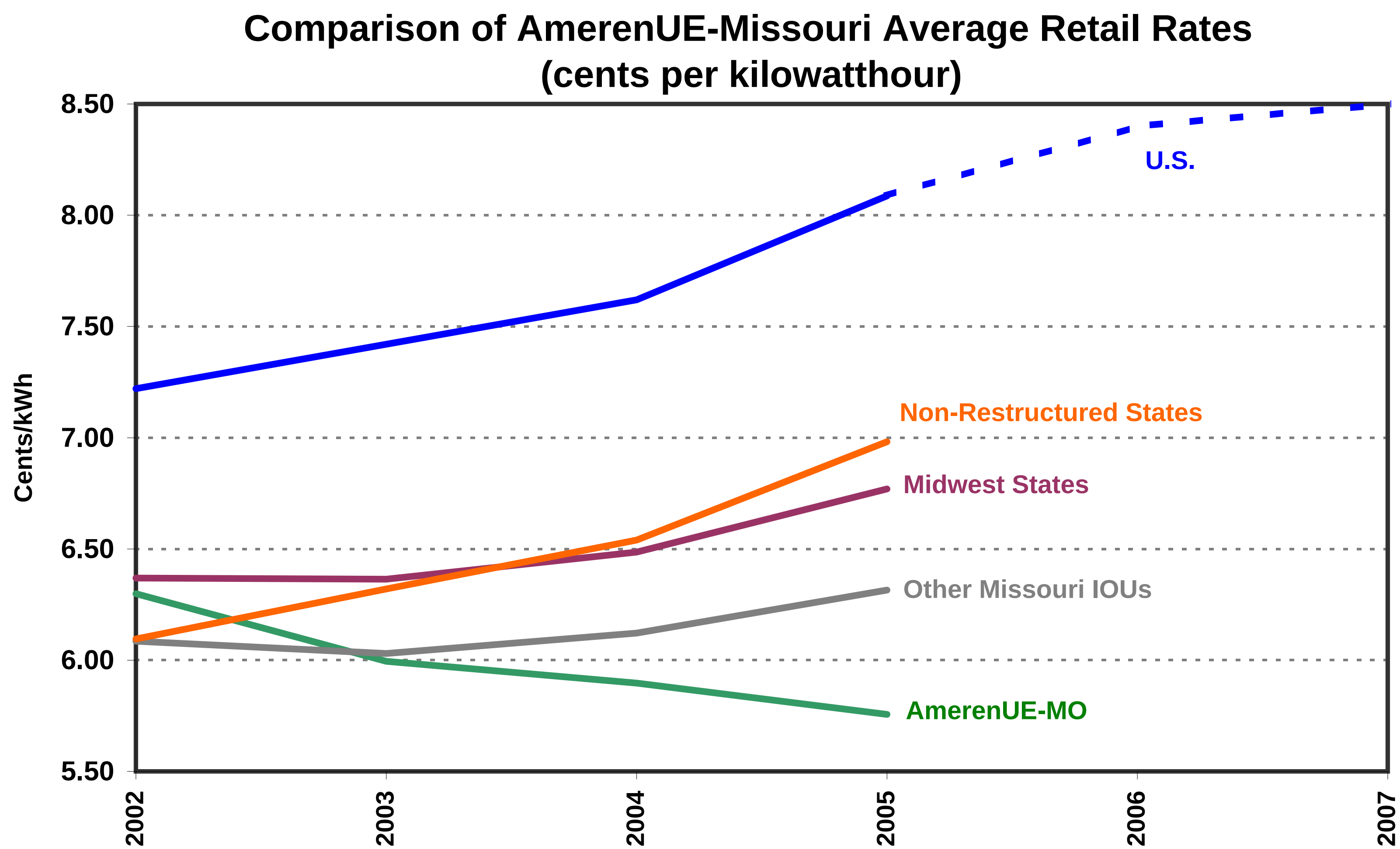
traditional regulation. This would give customers 100% of off-system sales margins above the cap if margins exceeded the cap due to unusually high power prices or other factors that would result in an extremely high level of off-system sales margins.

These matters are discussed by AmerenUE witness Shawn E. Schukar.

- In anticipation of the finalization of administrative rules relating to fuel adjustment clauses ("FAC") enabled by Senate Bill 179 ("S.B. 179"), the Company requests the ability to implement an appropriate FAC, subject to the promulgation of satisfactory rules and a satisfactory FAC mechanism. The Company's proposal also includes evidence allowing fuel and purchased power costs to remain in base rates, if a satisfactory FAC mechanism cannot be obtained. Similarly, the Company requests to establish an environmental cost recovery rider ("ECR") which can be used to address environmental costs, again subject to timely promulgation of necessary rules as required by S.B. 179 and satisfactory terms for any ECR.
- Consistent with recent policies employed by the Commission relating to pensions, the Company is also proposing a pensions and other post-retirement benefits ("OPEBs") tracking mechanism that removes volatility (for both the Company and ratepayers) associated with changes in appropriate pension and OPEB expenses, all as addressed by AmerenUE witness C. Kenneth Vogl.
- To ensure that the Company has the cash flow it needs to make timely investments in infrastructure, as well as address intergenerational equity matters, among other things, the Company's proposal, as explained by AmerenUE witness William M. Stout, reflects adoption of the life span approach to straight-line whole life depreciation, in

accordance with sound depreciation practices. The Company's proposal also includes recovery of terminal net salvage costs to cover costs to be incurred when power plants are retired, and continues to appropriately depreciate the Callaway Plant over its current depreciation period (ending when its current license ends) in accordance with sound depreciation principles and the Commission's decommissioning fund regulations.

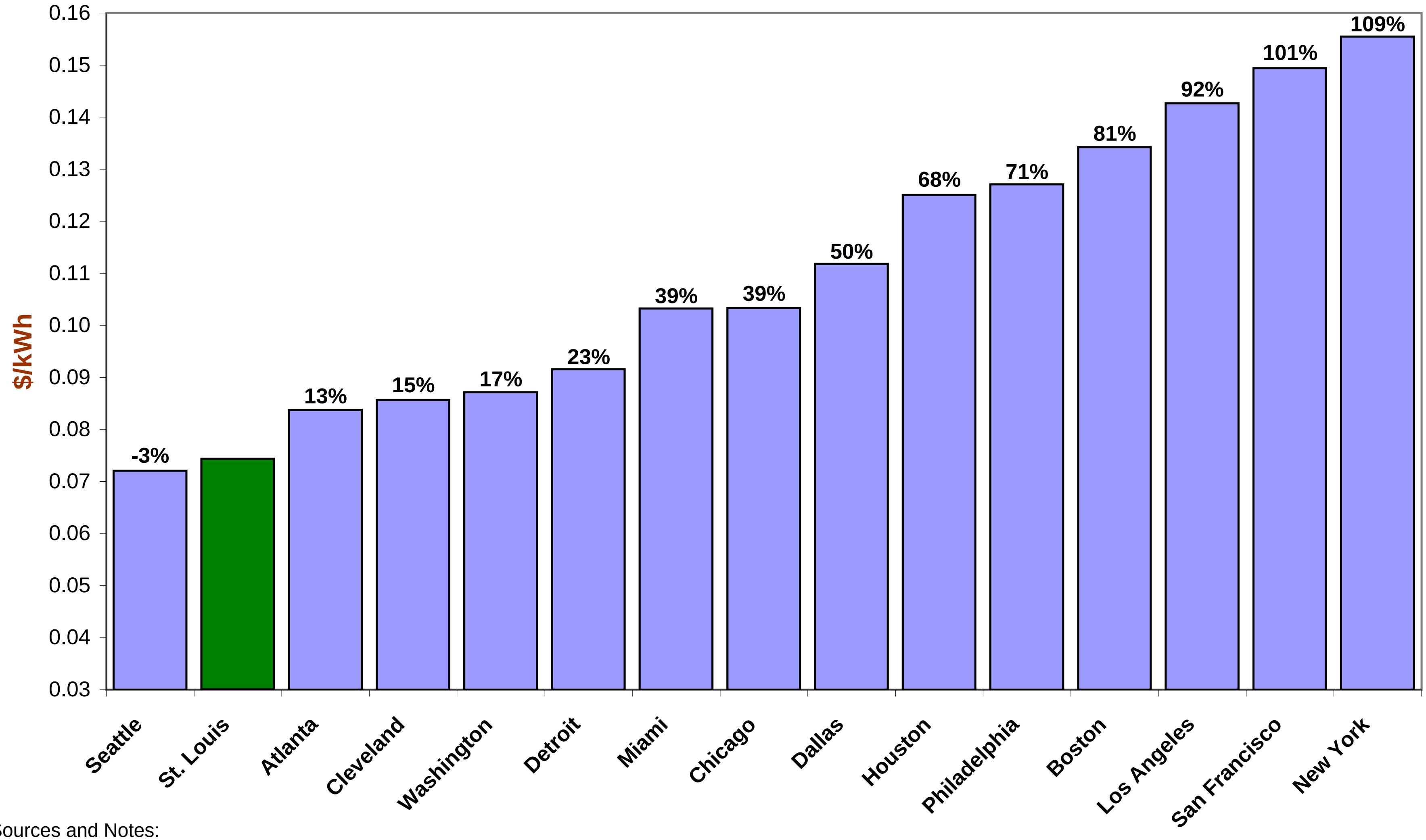
- The Company's proposal also includes consideration of the use of low-income assistance programs, and energy conservation programs, as discussed by AmerenUE witness Richard J. Mark. The Company is interested in working with the other stakeholders to continue its sponsorship of such programs.
- As explained by Mr. Moehn in his direct testimony, the Company is also supporting consideration of pursing greater renewable energy sources, including a commitment to construct 100 megawatts of wind power by 2010.
- The Company's proposal also includes the introduction of two new economic development tariffs to provide for discounts and incentives to attract new customers or retain existing customers, as well as encourage increased investment inside the City of St. Louis. These tariffs are explained in more detail by Company witness Robert J. Mill.



Source: DOE/EIA. 2006-2007 rates based on DOE forecast.
Non-restructured states are those states that have not deregulated the generation of electricity, similar to Missouri.
Midwest states based on Census Region definitions.
Other Missouri IOUs are Aquila, Empire District Electric, and Kansas City Power & Light.
Retail customers include residential, commercial, and industrial customers.

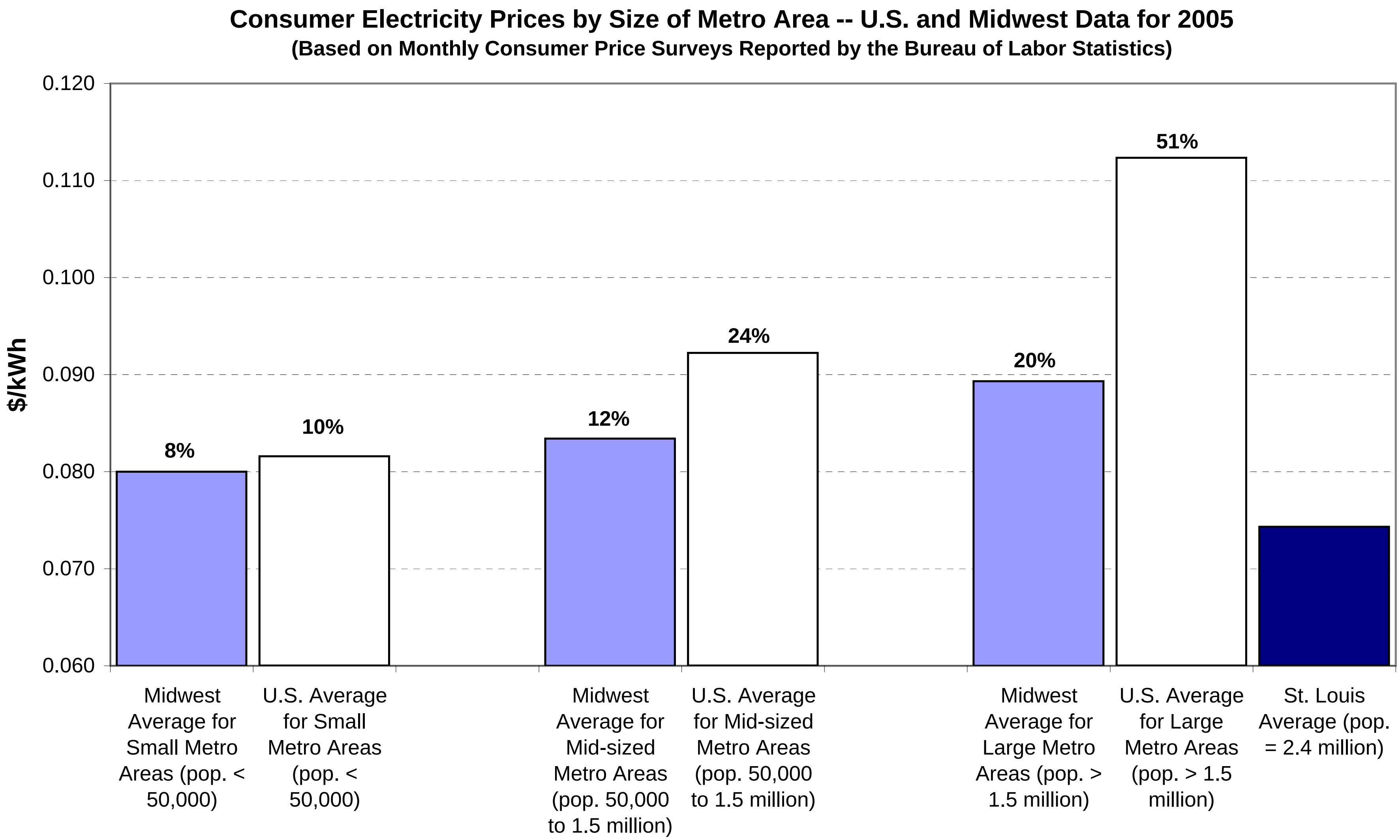
Schedule WLB-1

Average Consumer Electricity Prices (2005) for All Major Metropolitan Areas Reported by the Bureau of Labor Statistics



Sources and Notes:
BLS data based on monthly surveys of 10 residential electricity bills per metropolitan area.
Rates do not include seasonal discounts.
Source: www.bls.gov/data.
Percentages indicate extent to which each city's rates are higher than rates in St. Louis.

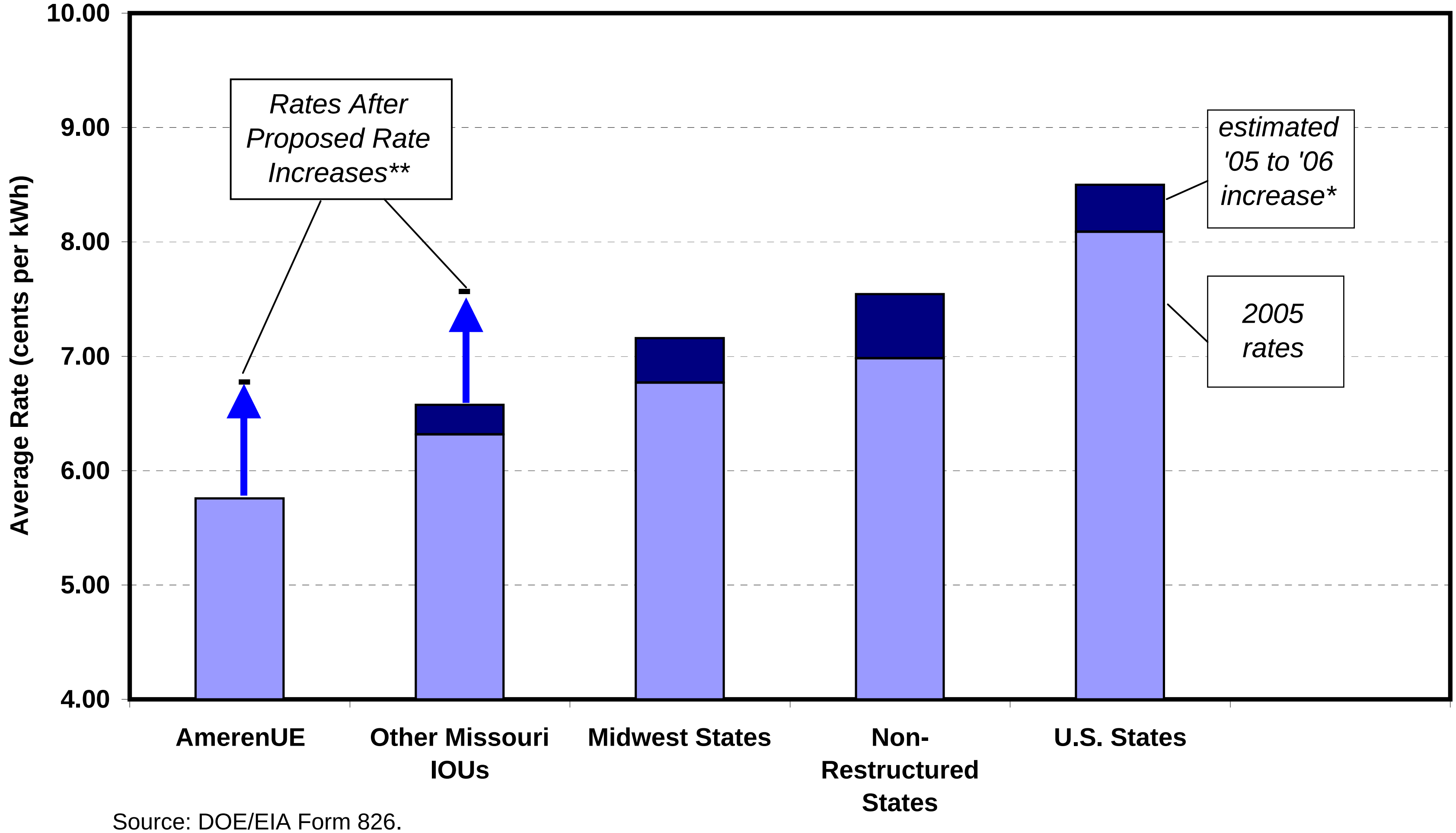
Schedule WLB-2



Sources and Notes:
BLS data based on monthly surveys of 10 residential electricity bills per metropolitan area.
Rates do not include seasonal discounts.
Source: www.bls.gov/data.
Percentages indicate extent to which each region's rates are higher than rates in St. Louis.

Schedule WLB-3

AmerenUE Average Retail Rates with Requested Increase Compared to Other Utilities



Source: DOE/EIA Form 826.

* U.S. based on DOE forecast; rest based on rates already in effect during the first quarter of 2006.

** Arrows based on requested percentage increases in company filings.

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

Midwest states based on Census Region definitions.

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

Retail customers include residential, commercial, and industrial customers.

Schedule WLB-7

EXECUTIVE SUMMARY

David A. Svanda

Principal, Svanda Consulting

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The purpose of my testimony is to: (1) discuss key regulatory and public policy considerations and principles that should guide the Commission's ratemaking decisions in this case; (2) address AmerenUE's superior performance and its comparatively low customer rates; (3) discuss the challenges faced by AmerenUE and the electric industry as a whole and the critical importance, in light of those challenges, of maintaining a financially healthy utility which can operate in a balanced and constructive regulatory environment; and (4) put into perspective the magnitude of AmerenUE's requested rate relief.

The principal conclusions reflected in my testimony are as follows:

1. The Missouri Public Service Commission and the Missouri legislature have provided a generally constructive regulatory environment for utilities in Missouri in recent years. Missouri has avoided regulatory structural problems that have created significant difficulties in states such as California. Missouri has also adopted policies that have allowed AmerenUE to remain financially strong, while providing customers with reasonable rates, and it has successfully used incentives to create favorable outcomes for AmerenUE and its customers. Although the regulatory environment in Missouri was criticized by credit rating agencies only a few years ago, the Commission has taken steps to move its policies into the mainstream, particularly in the areas of depreciation

cost recovery, return on equity and, most recently, the adoption of proposed rules enabling electric utilities to utilize a fuel adjustment clause as permitted by statute.

2. In this environment, AmerenUE has achieved superior performance resulting in a "win-win" situation for the Company and its customers. This superior performance includes high service quality, reliable service, impressively low rates compared to other electric utilities, and satisfied customers. In addition, AmerenUE has remained financially healthy enough to make significant investments in its infrastructure, maintain a solid credit rating, and pay reasonable returns to its investors.

3. The electric utility industry is facing a number of new challenges. Rate increases of the type sought by AmerenUE in this case are being necessitated across the country by rising fuel and purchased power costs, increases in other operating costs, substantial infrastructure investment needs, and increased costs of environmental compliance. The industry is facing additional uncertainties due to the increase in global competition for resources, the enactment of the Energy Policy Act of 2005 (which, among other things, repealed PUHCA), and the risk that additional, more restrictive environmental regulations will be enacted.

4. In this challenging environment, the regulator’s key duty is to appropriately balance the interests of all stakeholders. Ratemaking is not simply an exercise in applying mechanical formulas and “crunching numbers” to calculate the lowest possible level of rates for the short-term. Rather,

regulators must set policies that will operate in the long-term interest of consumers, utilities and ultimately the state in which they are employed. Maintaining a financially healthy electric utility benefits customers over the long term by maintaining credit ratings, lowering financing costs, and providing access to the capital necessary to finance current and future infrastructure and environmental investment timely and efficiently. Ratemaking is *not* a zero sum game where maintaining financially healthy utilities can only come at the expense of ratepayers over the long run.

5. The rate relief AmerenUE has requested is balanced, and it will result in rates that, when adjusted for inflation, are no higher than they were in 2002. Even with the proposed rate increase, AmerenUE's rates will have increased by less than the rates in the rest of the state, the Midwest, rates in other non-restructured states, and the nation as a whole. AmerenUE's rates will still be among the lowest in the country, and they will insure that AmerenUE maintains the financial strength to continue to invest in infrastructure and continue to provide customers with superior service at reasonable rates over the long-term.

6. Incentive mechanisms for items such as off-system sales, as discussed in AmerenUE's filing, are constructive tools that can provide benefits to utilities and to customers, particularly for a utility like AmerenUE and its customers given that AmerenUE has a high proportion of coal-fired baseload generation and excess energy to sell during significant portions of the year. AmerenUE's alternative off-system sales margin sharing mechanism provides

reasonable protection for AmerenUE against not achieving a “normal” level of off-system sales margins, while providing meaningful sharing for customers that would allow customers to realize a net benefit through the sharing mechanism versus under traditional regulation, even where AmerenUE is able to only modestly exceed the normal level of expected off-system sales.

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 jurisdiction electric operations. Based on the Company's revenue requirement, a $360,709,000 rate increase under traditional ratemaking is justified. I also provide the calculation of the Company's revenue requirement reflecting Rule 4 CSR 240-10.020.

The Company's revenue requirement is based on a test year consisting of the twelve months ended June 30, 2006, utilizing nine months of actual and three months of forecasted information, with certain known and measurable items updated through January 1, 2007. The three months of forecasted information will be updated with actual data once it becomes available, including the filing of supplemental direct testimony on or before September 30, 2006 supporting that updated information. The Company's rate base is updated through December 31, 2006 to reflect all additions to plant in service except for new business additions. The revenues and kWh sales have been adjusted to reflect normal weather. 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 known and measurable coal and transportation contract prices as of January 1, 2007 along with normalized plant generation and load requirements (see the testimony of Company witnesses Shawn E. Schukar, Robert K. Neff and Timothy D. Finnell). The remaining operating expenses have been adjusted to reflect (a) 2006 wage and salary increases, (b) annualized year 2006 pension expense and other employee benefits, (c) a reduction to incentive compensation expenses to reflect the annualized 2006 target level, (d) a reduction to reflect only two-thirds of the Callaway refueling expenses other than replacement power, (e) elimination of all expenses at Taum Sauk related to the reservoir failure and clean-up, (f) an annual level of operations and maintenance expenses for the three new combustion turbines generators (CTGs) purchased in March 2006, (g) increases in tree trimming expense, (h) the current level of charges by the Midwest Independent Transmission System Operator, Inc. (MISO) and (i) a three-year amortization of the expenses incurred to prepare and litigate this rate increase filing.

The depreciation expense has been increased to reflect proposed depreciation rates that include life span depreciation and terminal net salvage for the power plants. The proposed depreciation rates are applied to the depreciable plant balances at June 30, 2006 as well as to the additions to plant through December 31, 2006. The testimony of Company witnesses William M. Stout and John F. Wiedmayer provide support for the proposed depreciation rates. 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 the real estate taxes have been increased to reflect the real estate taxes on the three CTGs purchased in March 2006. Finally, the Company's revenue requirement is based on a 12.00% return on common equity (see the testimony of Company witnesses Kathleen C. McShane and James H. Vander Weide). Reflecting the above items, the Company's Missouri jurisdictional revenue requirement after reflecting an increase in uncollectible accounts is $2,401,880,000. This revenue requirement is $360,709,000 greater than the current operating revenues.

Rule 4 CSR 240-10.020 is a Commission rule that prescribes the method that the Commission must follow in accounting for income derived by utilities from their investment of depreciation funds. Following this rule, the Company's revenue requirement at the 12.00% return on common equity would be increased by $386,744,000 – an increase over current revenues of $747,453,000. Although the Company is not proposing rates to recover the full amount of the revenue requirement that it is legally entitled to as a result of the application of 4 CSR-10.020 in this case, application of the rule provides additional support for the $360,709,000 in additional revenue requirement that the Company is requesting. In other words, if the Commission were to find that adjustments to AmerenUE's revenue requirement are warranted, the Company would still be entitled to the full amount of the revenue requirement it is seeking due to the application of this rule.

EXECUTIVE SUMMARY

Robert K. Neff

Vice President, Coal Supply
Ameren Energy Fuels and Services Company (AFS)

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The purpose of my testimony is to explain the increasing coal and related transportation costs that affect AmerenUE's revenue requirements in this case.

The key conclusions in my testimony are:

1. AmerenUE will generate 79% of its electricity from coal-fired power plants in the test year AmerenUE is recommending for this case. At the same time, AmerenUE's 2007 average cost of a delivered ton of coal will have increased by 42% over the cost of a delivered ton of coal per AmerenUE's books for the period corresponding to the updated test year in AmerenUE's prior rate case proceeding in 2001. At the expected total annual coal burn in 2007, this equates to a coal cost increase of $162 million for 2007 over 2001.
2. 96% of the coal burned by AmerenUE originated in the Wyoming Powder River Basin (PRB) during the current 2006 test year, which, like other coal regions, have seen a substantial increase in coal and transportation costs since 2001. At the expected 2007 PRB burn level, AmerenUE's 2007 PRB coal and rail freight costs will account for $136 million of the $162 million total coal cost increase for 2007.
3. AmerenUE's 2007 delivered PRB coal costs will increase substantially over the current 2006 test year based on the 2007 PRB burn level. While

AmerenUE's coal and transportation costs have increased in 2006, and will significantly increase again in 2007, AmerenUE's costs are still well below current market prices because of the coal hedging program of Ameren Energy Fuels and Services Company which has hedged a high percentage of the coal and transportation needed to meet the 2007 burn via executed contracts with prices effective January 1, 2007.

4. AmerenUE's coal costs are expected to continue to increase toward market levels in subsequent years as existing contracts expire and new agreements are signed.

EXECUTIVE SUMMARY

Kathleen C. McShane

Senior Consultant and Executive Vice President of
Foster Associates, Inc.

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I have been asked to render an opinion on the fair rate of return on equity that would be applicable to Union Electric Company d/b/a AmerenUE. My analysis and recommendation took into account the following considerations:

(1) The allowed return on equity for AmerenUE should reflect the risk profile and cost of equity of comparable electric utilities so as to provide "a return commensurate with returns in other enterprises with corresponding risks." A sample of integrated electric utilities serves as the comparable group for AmerenUE.

(2) A fair and reasonable return falls within a range. Factors unique to AmerenUE that are relevant to the specification of the fair return within that range include both the downside risks as well as the utility's positive characteristics (e.g., competitive rates at levels well below the national average).

(3) In arriving at a recommended return, no single test result should be given exclusive weight. Each of the various tests employed provides a different perspective on a fair return. Each test has its own strengths and weaknesses, which vary with both the business cycle and stock market conditions. In the end, regardless of the insight that may be added by any individual test, the governing principles from the *Bluefield* and *Hope* decisions of the United States Supreme Court, as the Commission has emphasized, "require[] a

comparative method, based on the quantification of risk" in determining a fair rate of return on equity.

(4) The discounted cash flow ("DCF") and the risk premium tests are market-related tests for measuring the cost of attracting capital by reference to market values. By contrast, the comparable earnings test, which reflects returns on book equity, directly addresses the fairness standard as enunciated in the *Bluefield* and *Hope* decisions.

(5) For the purposes of determining a fair return on equity for a utility, a critical factor that needs to be recognized is that the cost of capital is determined in the capital markets. The cost of capital estimates reflect the market value of the firm's capital, both debt and equity. While the DCF and risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. The determination of a fair return on book equity needs to recognize that distinction and the resulting differences in financial risk.

(6) In principle, the comparable earnings test is most compatible with regulation on an original cost book value rate base. For purposes of this testimony, I have used the comparable earnings test results to demonstrate the reasonableness of the recommended return in relation to the level of returns being earned by unregulated non-utility companies with risks similar to electric utilities.

(7) The results of the DCF and risk premium tests used to estimate a fair return for AmerenUE, as well as my recommendation, are summarized below.

	Range	Average
Discounted Cash Flow	9.3-11.0%	10.0%
Capital Asset Pricing Model	11.75-12.25%	12.0%
Achieved Utility Risk Premiums	10.75-11.75%	11.25%
DCF-Based Risk Premium	10.3-10.8%	10.5%
Average of All Cost of Equity Methods		11.0%
Cost of Equity Reflecting Higher Financial Risk of AmerenUE Filed Capital Structure	11.6 – 12.3%	12.0%

The tests indicate that the required equity return is in the range of 10.0% (DCF) to 12.0% (CAPM). Based on all four tests, the indicated cost of equity as applied to the comparable electric utilities is approximately 11.0%. The comparable earnings test demonstrates the reasonableness, indeed, the conservative nature, of this range.

The proxy electric utility sample's market value common equity ratio is 62%. The allowed return on equity will be applied to AmerenUE's book value common equity ratio of 52%. The difference in financial risk between a market value common equity ratio of 62% and AmerenUE's book value common equity ratio of 52% requires an increase in the equity return requirement from 11.0% to a range of 11.6% to 12.3%. I recommend that the allowed return on equity for AmerenUE be set at the mid-point of the range, that is, at 12.0%.

EXECUTIVE SUMMARY

James H. Vander Weide, Ph.D.

Research Professor of Finance and Economics, The Fuqua School of Business, Duke University

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The purpose of my testimony is to provide an independent appraisal of the cost of equity of Union Electric Company d/b/a AmerenUE ("AmerenUE") and to recommend a rate of return on equity for AmerenUE that is fair, that allows AmerenUE to attract capital on reasonable terms, and that allows AmerenUE to maintain its financial integrity. This is important because in recent years the risk of investing in electric energy companies has increased as a result of significantly greater volatility in fuel prices, increased competition in the industry, more volatile purchased power and off-system sales prices, greater uncertainty in employee health care and benefit expenses, greater uncertainty in the cost of satisfying environmental regulations, and greater uncertainty in the expenses associated with system outages, storm damage, and security. With such increasing risk, investors demand an increased return on their investment.

I estimated AmerenUE's cost of equity in two steps. As the Commission stated in the recent Empire rate case, Case No. ER-2004-0570, "returns for [a utility's] shareholders must be commensurate with returns in other enterprises with corresponding risks." Accordingly, for my first step I applied several standard cost of equity methods, including the discounted cash flow model, the risk premium approach, and the capital asset pricing model, to market data for groups of companies of comparable risk.

In addition, in the Empire case the Commission recognized the need to adjust the results of that analysis for differences in financial risks manifested by the different capital structures of the utility that is the subject of the ratemaking and of the comparable companies to which it is compared. Thus, in my second step I adjusted the average cost of equity for my comparable companies for the difference between the financial risk of those companies in the marketplace and the financial risk implied by AmerenUE's filed capital structure.

My analysis indicates that AmerenUE would require a fair rate of return on equity equal to 12.2 percent in order to have the same weighted average cost of capital as my comparable companies. My analysis is summarized on the following table:

Cost of Equity Model Results

Method	Cost of Equity
Discounted Cash Flow	10.7%
Ex Ante Risk Premium	11.0%
Ex Post Risk Premium	11.4%
Historical CAPM	11.7%
DCF CAPM	12.8%
Average All Cost of Equity Methods	11.5%
Cost of Equity Reflecting Higher Financial Risk of AmerenUE Filed Capital Structure	12.2%

EXECUTIVE SUMMARY

Lee R. Nickloy

Director – Corporate Finance and Assistant Treasurer

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The purpose of my testimony is to recommend an overall fair rate of return for AmerenUE's electric utility business. I determine AmerenUE's capital structure, embedded cost of long-term debt and embedded cost of preferred stock. I also calculate the overall fair rate of return applied to rate base which is utilized in AmerenUE's filing in this case. I do so by using the fair rate of return applicable to the common equity component of AmerenUE's capital structure as developed by AmerenUE witnesses Kathleen C. McShane and Dr. James H. Vander Weide in their direct testimonies submitted in this case.

Ms. McShane develops and supports a fair return on common equity for AmerenUE's electric utility operations in the range of 11.60% – 12.30% with a recommended cost of equity for AmerenUE of 12.00%. Dr. Vander Weide's analysis indicates that AmerenUE would require a fair rate of return on equity equal to 12.2% to have the same weighted average cost of capital as comparable companies. For purposes of determining the overall fair rate of return for AmerenUE in this proceeding, I have conservatively used 12.00% as the Company's cost of common equity.

Using the capital structure (45.420% long-term debt, 0.099% short-term debt, 2.040% preferred stock and 52.441% common equity) and embedded costs of long-term debt (5.427%), short-term debt (5.11%) and preferred stock (5.189%), as shown on the various schedules attached to my testimony, along with this conservative estimate of the cost of common equity of 12.0% for AmerenUE supported by the analyses of Ms. McShane and Dr. Vander Weide, I derive an overall fair rate of return for AmerenUE of 8.869%.

EXECUTIVE SUMMARY

Shawn E. Schukar

Vice President, Ameren Energy

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I am providing testimony in support of the level of off-system sales margins and related costs used to determine AmerenUE's cost of service for the purpose of setting the Company's rates. In addition, I discuss an alternative off-system sales margin sharing mechanism that could be used to mitigate the risks associated with off-system sales margins for AmerenUE and its customers, as well as provide a balanced incentive for AmerenUE to reduce costs and increase revenues in order to maximize off-system sales margins. Finally, I address the market operation charges incurred by AmerenUE as a participant in the Midwest Independent Transmission System Operator, Inc. ("MISO").

In summary, my testimony states that:

1. AmerenUE's opportunities to realize off-system sales margins are dependent on its load serving obligations, generation resources, and market prices for energy. Test year off-system sales margins must be normalized and adjusted for known and measurable changes, which include: (1) the elimination of the Joint Dispatch Agreement, as discussed by AmerenUE witness Warner L. Baxter; (2) the expiration of the 1987 Power Supply Agreement with Electric Energy, Inc. ("EEInc."), as addressed by Mr. Baxter and by AmerenUE witnesses Michael L. Moehn and Professor Robert C. Downs; (3) the addition of Noranda Aluminum, Inc. as a retail customer; (4) the transfer of the Metro East (Illinois) service territory to AmerenCIPS; (5) the inclusion of the

Taum Sauk pumped storage facility for the full test year, as addressed by Mr. Baxter; (6) the addition of several gas peaker units that AmerenUE purchased in 2006, as addressed by Mr. Moehn; and additional capacity added at the Callaway Plant in 2005, as discussed by AmerenUE witness Charles D. Naslund; (7) weather normalization of load, addressed by AmerenUE witness Richard A. Voytas; (8) the extraordinary 2005 hurricane season, which I discuss; (9) the extraordinary interruption in rail transportation of coal that occurred in 2005, as discussed by myself and by AmerenUE witness Robert K. Neff; and (10) adjustments for known and measurable increases in AmerenUE coal and coal transportation costs, which are also discussed by Mr. Neff.

2. AmerenUE incorporated all of these adjustments in its production cost model (the operation of which is addressed by AmerenUE witness Timothy D. Finnell) to determine the appropriate normalized level of off-system sales margins to include as a reduction to the Company's cost of service. Using the model, I have determined that the appropriate level of off-system sales margins to use in setting AmerenUE's rates is $180 million annually.

3. As an alternative to selecting a fixed dollar amount for off-system sales margins to be included in AmerenUE's cost of service, the Company, subject to Commission approval, could implement a sharing mechanism which would mitigate the substantial risks associated with the variability of off-system sales margins for both AmerenUE and its customers, and would provide a balanced incentive for AmerenUE to maximize off-system sales margins. The structure of such a mechanism should include a very low "base" level of off-system sales margins in base rates, which are achievable under most conditions. Then AmerenUE and its customers should share off-system sales

margins above that amount. Customers would receive the lion's share of the off-system sales margins just above the base amount, with the Company's share of the margins increasing to higher levels to provide it with an incentive to lower its production costs and maximize off-system sales revenues. The parameters of this alternative sharing mechanism are depicted on the grid below.

Level of Off-System Sales Margins (in millions of $)	**Customer Share**	**AmerenUE Share**	**Effective Share for Customers**
$0 - $120	100%	0%	100%
$121- $180	80%	20%	100% - 93%
$181 - $360	50%	50%	92% - 72%
Over $360	100%	0%	72% or more

4. Pursuant to the Missouri Public Service Commission's order in Case No. EO-2003-0271, AmerenUE became a member of the MISO. As a member of the MISO, AmerenUE is a market participant that purchases and sells power in the MISO market. As a result of these activities, AmerenUE incurs unavoidable administrative and market costs. The level of costs that are included in AmerenUE's cost of service has been adjusted using expected MISO costs for 2006, which will be updated to include actual 2006 MISO costs when the test year is updated. The 2006 costs are being used to avoid the inclusion in the revenue requirement of the higher costs resulting from the initial inefficiencies experienced during the initial operations of MISO's Day 2 Markets.

EXECUTIVE SUMMARY

Timothy D. Finnell

Supervising Engineer of the Operations Analysis Work Group / Pricing and Analysis Department/Corporate Planning Function

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The purpose of my testimony is to explain the production cost model used to normalize fuel costs, the variable component of purchased power costs and off-system sales revenues for this case. 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 2005 hourly load data was modified for the transfer of the AmerenUE Metro East (Illinois) load to AmerenCIPS and for the addition of Noranda Aluminum, Inc. Adjustments were made so that each change was effective for the entire year.

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 fuel costs, variable purchased power costs and off-system sales revenues calculated by the PROSYM model are $599 million, $26 million, and $311 million, respectively. These results are utilized by AmerenUE witness Gary S. Weiss in developing the revenue requirement for AmerenUE.

EXECUTIVE SUMMARY

Professor Robert C. Downs

Professor of Law, University of Missouri-Kansas City

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AmerenUE's capital stock in EEInc. was purchased with shareholder funds which, as AmerenUE witness Michael L. Moehn explains, are funds that are excluded from the calculations used by the Missouri Public Service Commission ("Commission") to set electric rates. Because AmerenUE is a wholly-owned subsidiary of Ameren Corporation and given that AmerenUE shareholders bought AmerenUE's EEInc. stock, the EEInc. stock owned by AmerenUE is held for the ultimate benefit of the shareholders of Ameren Corporation. EEInc.'s Board has an obligation as a matter of law to maximize the value of those shares as well as all other shares of capital stock of the corporation. This is a very fundamental and basic tenet of corporate law in all jurisdictions, including in Illinois where EEInc. is incorporated. Directors do not owe that duty to third parties, including Missouri retail ratepayers.

As Mr. Moehn explains, the Missouri Office of the Public Counsel ("OPC") has previously taken the position that EEInc. should forego profits (or be forced to forego profits) on the sale of power by continuing to sell power to AmerenUE at cost. OPC's position flies directly in the face of the binding legal obligation of EEInc.'s Board to maximize the value of the stock held by EEInc. shareholders. Consequently, it would be improper for EEInc to sell power at cost to one of its shareholders or anyone else when it can sell power at higher market prices. Doing so would improperly shift benefits to which shareholders are legally entitled to customers, in violation of the EEInc.'s Board's fiduciary duties as a matter of law.

EXECUTIVE SUMMARY

Charles D. Naslund

Senior Vice President and Chief Nuclear Officer

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The purpose of my testimony is to: (a) provide a background of the Callaway Nuclear Plant's performance and its importance to Missouri; (b) discuss the substantial capital additions made to the Callaway Plant since the Company's last rate proceeding (Case No. EC-2002-1); (c) provide up-to-date information on several changes to the Callaway Plant's security infrastructure and the associated operation and maintenance ("O&M") cost increases, nearly all of which were driven by governmentally-mandated requirements following the September 11, 2001 terrorist attack; (d) discuss a key Callaway Plant operation, its regular (every 18 months) refueling outages; and (e) provide information related to a future decision that will have to be made regarding whether or not the Company should seek to relicense the Callaway Plant.

Callaway's production has exceeded that of most other nuclear units. Callaway's lifetime generation was the sixth highest among the 103 operating U.S. nuclear power plants, and 22nd in the world, out of 443 nuclear plants operating in 30 countries. Callaway has over 1,000 full-time employees and contractors. In 2005, the plant accounted for $9.5 million of AmerenUE's property taxes paid to Callaway County, with $6.5 million of that amount going to local schools.

Significant major component replacements have been made to the Callaway Plant since 2001, including the 2005 replacement of the plant's four steam generators--the giant boilers that produce steam for generating electricity. In total, the Company made $449,677,723 in capital additions to the plant over approximately the past 5 years.

In order to meet new security requirements imposed by the Nuclear Regulatory Commission ("NRC") after September 11, 2001, the Company implemented a number of capital modifications by October 2004 and substantially increased staffing and other O&M expenses. These security-related costs have added $5 million per year to the Callaway Plant's O&M cost structure.

The Company completed a regular refueling outage at the Callaway Plant in November of 2005. By combining scheduled maintenance and capital addition work with such refuelings, the Company minimizes outage time and maximizes the efficiency of these necessary operations.

The NRC license for the Callaway Plant will expire approximately 18 years from now in 2024. The NRC's process for extending licenses an additional 20 years normally is started about 10 years before the license is scheduled to expire. Consequently, AmerenUE will not be deciding whether or not to commence the relicensing process until around 2014. The single most critical consideration in determining whether or not relicensing may be feasible is the condition of the reactor vessel itself. The additional data gained over the next approximately eight years will be critical in assisting the Company in making a relicensure decision. During that time, the Company will continue to do all the things necessary to preserve this option.

EXECUTIVE SUMMARY

Mark C. Birk

Vice President of Power Operations

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The purpose of my direct testimony is to explain AmerenUE's ongoing investments in its electric generation infrastructure and to provide a brief summary of the upper reservoir failure at the Taum Sauk pumped-storage facility and an update on related matters. The following are the principal points of my testimony:

(1) From January 1, 2002 through March 31, 2006, AmerenUE spent more than $1.7 billion on generating infrastructure. More than $1.3 billion was spent on AmerenUE's non-Callaway generating assets, including the addition of several new combustion turbine generating units. Approximately $638 million of investments have been placed in service since January 1, 2002 at the Company's coal-fired and hydroelectric units alone. From January 1, 2002 through December 31, 2006, the capacity of AmerenUE's generating assets (excluding the addition of peaking units) has also been increased by approximately 434 megawatts (MW). Over that same period, AmerenUE has also increased the "Equivalent Availability" (i.e. the percentage of time an electric power generating unit was available for service during a period) of its coal-fired and hydroelectric units by approximately 10%. These investments have also allowed a substantial increase in the production of electricity on a megawatt-hour (MWh) basis from the Company's coal-fired and hydroelectric plants as evidenced by the 22% increase from 2002 to 2005, from 36.3 million MWhs in 2002 to 44.2 million MWhs in 2005.

(2) AmerenUE's ongoing operations and maintenance (O&M) expenditures are escalating due to several factors, including the aging of AmerenUE's fleet (the average fossil unit age is 39 years), continuing increases in raw material and outside services costs, increasing environmental expenses, and increasing capacity factors, particularly at AmerenUE's baseload plants. Capacity factors are increasing because electric loads continue to increase while no new baseload generation has been brought on line since 1984. Through the use of initiatives such as AmerenUE's Plant Reliability Optimization, Plant Maintenance Optimization, and Corrective Action Programs, and other operational performance improvements with respect to its generating fleet, AmerenUE has been able to meet the ever increasing electrical energy needs of Missouri customers in an economic manner.

(3) There is a definite need for additional generation capacity in Missouri and throughout the nation in order to maintain the reliability of the electric power supply. As the 2003 blackout in the Northeast showed, local generation close to the load provides for the most secure and reliable way to supply electricity. AmerenUE has continued to invest in new generation, as needed, to meet its increased needs for capacity. Over the past approximately four-year period, AmerenUE has invested more than $700 million in additional peaking capacity needed both to meet its peak needs and to maintain a prudent level of operating reserves.

(4) AmerenUE will be required to make significant environmental capital investments and incur associated O&M costs to meet the requirements of existing, updated, and new environmental regulations, including the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Missouri NOx SIP (State Implementation Plan) Call. These environmental capital investments and increased ongoing O&M costs

necessitated by those regulations will present significant financial and operational challenges and risks while overall emissions are being reduced.

(5) Three different entities, Rizzo Associates (an engineering group with dam expertise hired by AmerenUE), a project team consisting of Federal Energy Regulatory Commission (FERC) engineers familiar with dam safety issues, and a FERC Independent Panel of Consultants (a panel of 3 independent dam design engineers hired by FERC) have investigated the cause of the Taum Sauk upper reservoir failure which occurred on December 14, 2005. They all generally agree on the root causes of the failure, some of which date back to the plant's original construction in the early 1960s. We are thankful that there was no loss of life from this event and are working diligently to use what has been learned from these investigations to develop a corrective action plan to ensure that a similar event does not happen again. Though our investigation shows that everyone involved in this incident was well-intentioned, we recognize that the consequences of the failure were substantial. At every step of the way our employees took actions they believed were sufficient to protect the facility's safety and the safety of the public, though in hindsight, those steps clearly proved to be inadequate. We are working very hard to take all necessary steps to prevent any similar accident in the future. No final decision on whether the Taum Sauk Plant will be rebuilt has yet been made, but over the next few months we will continue to evaluate options for a possible rebuild of the Taum Sauk Plant. We have asked consultants to begin work on preliminary designs associated with a new upper reservoir and would expect, if a decision is ultimately made to rebuild the plant, that it could be available for service by the summer of 2009.

EXECUTIVE SUMMARY

William M. Stout

William M. Stout, President of the Valuation and Rate Division of Gannett Fleming, Inc., a consulting firm that provides depreciation studies and other regulatory consulting services.

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I have conducted hundreds of depreciation studies during my over thirty-year career. I also have served as an instructor at courses offered by Depreciation Programs, Inc., the Society of Depreciation Professionals, and the American Gas Association/ Edison Electric Institute. The purpose of my testimony is to recommend the appropriate approach to the depreciation of power plants. I recommend that the Commission adopt the life span approach to straight-line whole life depreciation and allow an accrual for both interim and terminal net salvage during the life of power plants. I also recommend that the life span for the Callaway Nuclear Power Plant be based on the expiration date of the current license.

Neither the retirement dates nor the cost of decommissioning power plants is speculative. There have been many power plants retired over the years including plants owned and operated by AmerenUE. Although the retirement of these plants is not imminent, the dates of their retirement and the cost of decommissioning them can be estimated with reasonable accuracy.

Facilities such as power plants have unique, but predictable, service life characteristics. During the life of the plant, interim additions and retirements occur on a regular basis. At the end of the plant's life span, there is concurrent retirement of all installations regardless of age. The life span approach recognizes these characteristics and uses a unique survivor curve for each installation year. This improves the matching of depreciation expense with the loss in service value as compared to the use of the same average survivor curve for all installation years. The life spans for AmerenUE's power plants are at the high end of the probable range of life spans.

Power plants experience both interim and terminal net salvage. The estimates of terminal net salvage or decommissioning costs for AmerenUE’s plants are reasonable when compared with the estimates of other plants and the cost to originally install the facilities. It is not sound ratemaking to wait until such costs are incurred to recognize them for ratemaking purposes. Such costs are part of the full cost of providing service and should be recognized during the period that the plant renders service.

The use of the life span method, as compared to the use of an average survivor curve for all installation years, results in better matching of depreciation expense with the service value rendered by the plants. The improved matching is more equitable for customers. Recovery of terminal net salvage during the life of the power plant from the customers receiving service from the plant is equitable. Recovery of terminal net salvage after the power plant is retired from customers that did not receive such service is not equitable.

The probable retirement date that should be used for determining the depreciation expense for the Callaway Nuclear Power Plant in this proceeding is the current license expiration date of October, 2024. It is premature to recognize a possible license extension before it is granted and before any conditions related to such an extension are known. This is consistent with the Commission’s regulations on decommissioning fund deposits which require accruals to be based upon the utility’s current NRC license.

EXECUTIVE SUMMARY

John F. Wiedmayer

Project Manager, Depreciation Studies Practice
Gannett Fleming, Inc.

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The purpose of my testimony is to sponsor the depreciation study conducted for Union Electric Company d/b/a AmerenUE (the "Company" or "AmerenUE"), titled "Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant at December 31, 2005." The recommendations in the direct testimony of AmerenUE witness William M. Stout in support of adopting the life span approach to straight-line whole life depreciation, the accrual of both interim and terminal net salvage during the life of power plants, and the life span for AmerenUE's power plants are incorporated into my depreciation study.

My testimony addresses (1) the methods and procedures I used in the depreciation study, (2) the statistical analyses of service life and salvage data I performed, (3) my estimates of survivor curves and net salvage percents, (4) my calculation of depreciation accrual rates, (5) my proposed amortization of the reserve variance and (6) several examples of the manner in which the study results are presented in the depreciation study report. The specific annual depreciation accrual rates that I recommend the Commission approve are presented in Schedule 1 of Schedule JFW-E1 and the remaining life amortization of the variance between the calculated accrued depreciation and the book accumulated depreciation that I have determined are presented in Schedule 2 of Schedule JFW-E1.

These annual depreciation accrual rates and the reserve variance amortization are based on standard professional and industry practices using estimates of survivor curves and net salvage percents. These estimates are based on informed judgment that incorporates statistical analyses of historical retirement data, field reviews of the property, discussions with management regarding the outlook for plant, and a review of the estimates made for other electric utilities. Further, my estimated survivor characteristics for Production Plant incorporate estimated dates of final retirement that are consistent with industry experience and the outlook of AmerenUE management

EXECUTIVE SUMMARY

Thomas S. LaGuardia

Member, LaGuardia & Associates, LLC

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I am a member of LaGuardia & Associates, LLC, a consulting engineering company. I was formerly President of TLG Services (TLG), an Entergy Nuclear Company until I retired. In that position I was responsible for the technical and business management of engineering and field services in the areas of decontamination, decommissioning, waste management and general engineering for nuclear and fossil-fueled electric generating stations.

My testimony addresses the results of an updated (from the earlier 2001 TLG study) decommissioning, i.e., dismantling cost study prepared by TLG for two distinct dismantling scenarios for each of AmerenUE's fossil-fueled electric power generating station. The base case is for the complete dismantling of the generating station, including removing the steam turbine-generators, boilers, fuel handling systems, and all plant equipment and above-ground structures, except for the switchyard, and restoration of the site upon cessation of operations. The Alternative case assumes limited and partial dismantling of the station, including removal of hazardous waste, and the removal of the non-power block structures, stacks, coal handling facilities, ash ponds, and screen houses. Finally, the power block structures will be secured in a safe condition for an extended duration dormancy. A summary of the costs for the base case and alternative case is shown for the following Ameren fossil-fueled power plants:

SUMMARY OF DISMANTLING COST ESTIMATES

Station	No. of Units	Megawatts (Total)	Base Case: Full ($, Thousands)	Alternative Case: Partial Dismantle ($, Thousands)
Labadie	4	2520	131,392	52,478
Rush Island	2	1260	70,230	26,873
Sioux	2	1050	70,399	34,111
Meramec	4	940	74,643	35,446
Venice	6	400	44,970	24,892
Total Cost			391,634	173800

Retirement is the planned and orderly removal from service of a generating station. Upon retirement, the facility may either be rendered safe indefinitely (through on-going monitoring, maintenance, repair and security measures), or dismantled. Maintenance and repair indefinitely is a costly process for a facility that has no further use, and accordingly prompt dismantling following retirement of the station is the favored approach.

The TLG cost estimating staff visited each of the five electric power generating stations to become familiar with the equipment and general arrangement. The updated study was developed using the U.S. Department of Labor, Bureau of Labor Statistics indices to adjust the dismantling costs from 2001 to 2005 dollars. Site specific changes (additions) were included in the updated study to reflect actual site equipment.

The results of the cost estimates are consistent with other studies TLG has prepared for over 250 fossil-fueled electric power units. Each plant is unique in terms of the site-specific differences of type of equipment, building construction and site remediation. These factors were incorporated in the estimates prepared for AmerenUE.

Utilities and regulators have begun to recognize the need to dismantle older plants that are no longer economical to operate either through obsolescence, or more restrictive emission requirements. TLG was directly involved with two such dismantling programs at Texas on the Comal and Seaholm power stations, where we provided planning and oversight to contractors dismantling the fossil-fueled power equipment. Kansas City Power & Light dismantled a 100 MW power station in Missouri that was only 40 years old, because the power needs were provided by the Wolf Creek nuclear power station. The Florida Public Service Commission now requires its utilities to account for fossil-fueled power plant dismantling costs in its rate structure to customers so current customers will pay their respective share of the dismantling costs.

TLG recommends that Ameren review these dismantling cost estimates periodically to account for changes in regulations, dismantling techniques, hazardous waste disposal cost increases, and inflation-related expenses.

EXECUTIVE SUMMARY

C. Kenneth Vogl

Consultant, Towers Perrin

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My testimony addresses two key issues related to pension and OPEB expense.

First, I identify and discuss the primary reasons for increases in FAS 87 pension expense and FAS 106 OPEB expense over the past few years. These reasons are listed below:

- Declining interest rates – Lower interest rates translate into lower discount rates. A lower discount rate increases both the pension and OPEB plan liabilities. The increase in liabilities worsens the funded status of both plans, which increases FAS expense.
- Lower than expected investment returns from 2000-2002 – Trust returns for this period were much lower than the assumed returns for each year. This resulted in fewer assets than expected, which worsened the funded status of the pension and OPEB plans, and ultimately increased FAS expense.
- Higher than expected annual increases in medical costs – Medical inflation has been very high over the past several years (i.e., 10%-20% annual increases). This has caused OPEB plan liabilities to increase, thereby worsening the plan's funded status and increasing expense.

I note the above reasons for increases in pension and OPEB expense were experienced by the majority of other organizations offering these types of plans. AmerenUE's experience has been similar to other companies' experience.

I also describe other changes made by AmerenUE to help offset some of the increase in expenses (e.g., plan amendment to shift some OPEB cost to retirees, reflection of Medicare Part D).

In addition I propose a procedure for the regulatory treatment of pension and OPEB expense. This proposed procedure will ensure that ratepayers are not over- or under-charged for these benefits. This is done by creating a tracking amount (regulatory asset/liability) that continually tracks the mismatch between the actual cost of pension and OPEB benefits and the cost collected in rates for these benefits. This tracking amount is then built into the next rate case. Therefore, over time, the amounts collected in rates will equal AmerenUE's true cost of providing pension and OPEB benefits.

EXECUTIVE SUMMARY

Michael L. Moehn

Vice President of Corporate Planning
Ameren Services Company

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The purpose of my testimony is to discuss AmerenUE's resource plan. The resource plan is presented in detail in the Company's December 2005 Integrated Resource Plan (IRP) filing. That filing outlined AmerenUE's plans to acquire 1,350 megawatts (MW) of combustion turbine generators (CTGs) as well as its desire to achieve material levels of demand response, energy efficiency, and renewable energy. My testimony also addresses AmerenUE's ownership of shares of capital stock of Electric Energy, Inc. ("EEInc.") and the expiration of AmerenUE's former purchased power contract with EEInc. Finally, my testimony addresses AmerenUE's willingness to work with all stakeholders toward implementing demand-side management programs and adding renewable energy to AmerenUEs' portfolio.

1. In order to meet its short-term planning reserve margin requirement AmerenUE needs approximately 400 MW of additional generating capacity beginning in 2006. Long-term reserve margin requirements are higher than short-term reserve margin requirements due to the greater load forecast uncertainty associated with longer time horizons. By 2014, AmerenUE's additional capacity needs were projected to be substantially higher.

The CTGs recently acquired by AmerenUE to address the Company's 2006 need for capacity consist of 8 simple cycle GE 7EA 80 MW combustion turbines at the Audrain, Missouri facility that AmerenUE purchased from NRG Energy, Inc. (NRG), and 10 simple cycle GE 7EA 75 MW combustion turbines at the Goose Creek and Raccoon Creek facilities located in central Illinois that AmerenUE purchased from Aquila, Inc. (Aquila). On a present value of revenue requirements basis, the acquisition of the NRG and Aquila plants is more economic and less risky than all other expansion plan options by amounts ranging from $173 million to $409 million, depending on the technology deployed.

2. AmerenUE's long-term, cost plus 10%, power supply agreement with EEInc., which provided the Company with power from EEInc.'s Joppa, Illinois generating plant, expired by its own terms on December 31, 2005. At that time, EEInc. ceased selling power on a cost plus basis, and instead received authority from the Federal Energy Regulatory Commission (FERC) to sell power from the Joppa Plant at market prices. Consequently, AmerenUE no longer has the opportunity to purchase power from EEInc.

EEInc. was originally formed in 1950 by several independent "Sponsoring Companies"— Union Electric Company (UE), Central Illinois Public Service Company, Illinois Power Company, Kentucky Utilities Company and Middle South Utilities, Inc. -- for the purpose of constructing, owning and operating an electric generating plant to provide power to a gaseous diffusion uranium plant owned and operated by the United States Atomic Energy Commission (AEC) near Paducah, Kentucky. In the early 1950's, UE sought and received authority from the Commission to purchase shares of EEInc. stock. The Sponsoring Companies, including UE, entered into power purchase agreements with EEInc. for the purchase of any excess power produced by the Joppa Plant beyond that required by the AEC.

AmerenUE's stock in EEInc. was purchased with shareholder, not ratepayer, funds, and has always been treated as a "below-the-line" item for ratemaking purposes, meaning that the investment in the stock is not and has never been on AmerenUE's books as an asset on which a return is figured in calculating the rates paid by AmerenUE's Missouri ratepayers.

Since January 1, 2006, EEInc. has been selling the output of the Joppa Plant at market-based rates pursuant to market based rate authority obtained from the FERC, like many generators since the emergence of regional and national markets for power. In fact, with the termination of the Joint Dispatch Agreement, AmerenUE's excess energy formerly transferred to Ameren affiliates at incremental cost will be sold at market rates.

The Office of the Public Counsel (OPC) has taken the position that EEInc. shareholders should force the EEInc. Board, which consists in part of officers or employees of AmerenUE or its affiliates, to sell power to AmerenUE at cost. FERC has rejected OPC's position, which, as AmerenUE witness Robert C. Downs explains, is improper and unlawful because it seeks to compel EEInc.'s Board to act contrary to the best interests of that corporation and so to violate basic principles of corporate governance.

3. AmerenUE's vision is to take a strategic approach to the development of a sustainable energy plan that could achieve reasonable near-term reductions of 10% of both annual energy and capacity growth, with long-term capacity goals, depending upon how market prices develop, as high as 300 MW as modeled in the AmerenUE 2005 IRP filing**.** AmerenUE will evaluate opportunities, develop action plans, and development implementation plans that are expected to result in meaningful levels of reduced energy and peak demand growth. AmerenUE continues to explore ways to achieve capacity through

EXECUTIVE SUMMARY

Richard Mark

Senior Vice President of Missouri Energy Delivery

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AmerenUE continues to make improvements to its electric utility distribution infrastructure to improve the service the Company provides. AmerenUE recognizes that reliability expectations of its customers continue to grow and, accordingly, the Company has invested approximately $500 million over the last three years to maintain and improve its infrastructure and to improve customer service. These efforts include identifying vulnerable sub-transmission circuits with state of the art lightning tracking software, the implementation of a tap fusing program and accelerating its pole replacement and tree trimming schedules as well as multiple improvements in its customer service systems and storm response capabilities.

In order to continue meeting customers' higher reliability expectations, AmerenUE is committed to maintaining and improving its distribution infrastructure. The costs involved in maintaining the condition of our distribution system infrastructure continue to rise. As an example, since January of 2002, transformer prices have risen by 57%. Other costs have also risen significantly. Since 2002, the cost of aluminum overhead conductor has grown 93%, the cost of poles has gone up 34% and the cost of copper underground cable has grown 147%. These capital expenditure levels are expected to continue to grow.

As part of its efforts to meet its customers' expectations, AmerenUE has made a concerted effort to improve its customer service. These efforts included improvements at its call centers, upgrades to its billing system and expanding options available to customers on the Company's website, Ameren.com. AmerenUE routinely measures customer satisfaction by subscribing to various surveys from outside, independent companies such as J.D. Power and Associates. AmerenUE also conducts its own surveys. The results of these surveys show that the Company provides excellent customer service. AmerenUE's internal survey found 90% of AmerenUE customers rated their overall experience with the Company as either meeting expectations or above expectations and J.D. Power recently awarded AmerenUE's customer contact centers with the certification for providing "An Outstanding Customer Service Experience."

AmerenUE has also made significant contributions to various low-income customer assistance and energy efficiency programs, including $8 million in contributions to the Dollar More Program, $9 million for a Community Development Corporation and $6 million for weatherization and efficiency programs. AmerenUE is committed to continuing its efforts to assist our customers who are in need and to help all customers conserve energy. The Company will work collaboratively with the Commission and other key stakeholders to continue current low-income energy assistance programs and energy conservation programs as appropriate, as well as to develop new programs where beneficial.

demand side management, including the proposed Industrial Demand Response (IDR) pilot discussed by AmerenUE witness Robert J. Mill.

Finally, AmerenUE is willing to commit to adding 100 MW of wind power to its generating fleet by 2010 on the assumption that doing so is technologically feasible and is supported by stakeholders in this proceeding. AmerenUE also remains willing, in the context of this proceeding, to explore with all stakeholders ways to implement other renewable sources of energy where feasible.

EXECUTIVE SUMMARY

Maureen A. Borkowski

Vice President of Transmission
Ameren Services

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The purpose of my testimony is to explain the changes in AmerenUE's Transmission Plant since 2001; to describe the transmission projects increasing the import capability into Missouri by 1300 megawatts ("MW") as agreed to in the Stipulation and Agreement in Case No. EC-2002-1; and to explain how membership in the Midwest Independent Transmission System Operator, Inc. ("MISO") is reflected in transmission revenues and expenses during the test year.

AmerenUE has made significant investment in its transmission facilities to continue to provide reliable service to its customers. From January 1, 2002, through March 31, 2006, AmerenUE has increased the amount of its investment in Transmission Plant by $107,062,057. This increase in transmission investment reflects in part AmerenUE's compliance with the Stipulation in Case No. EC-2002-1, to increase its import capability into Missouri by 1300 MW.

Various adjustments to transmission revenues and expenses in the calculation of AmerenUE's revenue requirement set out in the testimony of AmerenUE witness Gary S. Weiss were necessitated by the operation of MISO. Revenue and expenses related to rate adjustment mechanisms intended to recover lost transmission revenues of Transmission Owners joining MISO (MISO Schedules 18 and 19) have terminated and will not recur, and so have not been included in the calculation of the revenue requirement. Similarly, the collection period for the recovery of certain lost transmission revenues resulting from the elimination of the through and out rates for transactions between MISO and PJM (MISO Schedules 21 and 22) has ended and will not recur, and so neither revenues nor expenses related to that process have been included in the calculation of the revenue requirement. Likewise, transmission service charges to serve load within the PJM Interconnection (MISO Schedules 7 and 8) were permanently eliminated. Additionally, charges reflecting the costs of operating the Regional Transmission Organization were included as an expense in the calculation of the revenue requirement under MISO Schedule 10. Finally, the allocation of MISO transmission revenues between AmerenUE and AmerenCIPS was updated as of January 1, 2006 to reflect the appropriate percent of Transmission Plant investment.

EXECUTIVE SUMMARY

Wilbon L. Cooper

Manager of the Rate Engineering Department
Ameren Services Company

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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

<u>Sales/Revenues</u>

Sales, revenues and rate billing units, for the twelve months ending June 2006 test year, 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.

<u>Class Cost of Service</u>

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 ended June 2006. Included in this study was the use of the Average and Excess 4NCP 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 <u>amount of capacity</u> the Company must add to its generation system to provide for its customers' maximum demands. However, the <u>type of capacity</u> (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 4NCP 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 27%, Small General Service 11%, Large General Service 8%, Small Primary Service 11%, Large Primary Service 29% and Large Transmission Service 7%.

Rate Design

While cost based rates are the 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. Theses factors are more fully developed in the testimony of Company witness Mr. Hanser. Considering the cost based class revenue requirements from Mr. Warwick's study and proper consideration of the other factors developed in Mr. Hanser's mentioned testimony above, the Company is proposing to cap the residential class rate increase at 10%. The shortfall in the cost based revenue requirement of the residential class associated with the residential rate cap proposal was allocated to the Company's remaining major customer classes based on each class' "original" cost based (i.e. at equal class rates of return) proportionate share of the total cost based revenue requirement. The class revenue requirements from this residential rate cap proposal resulted in the following percentage increases for the Company's major customer classes: Residential 10%, Small General Service 24%, Large General Service 20%, Small Primary Service 24%, Large Primary Service 43% and Large Transmission Service 19%.

Miscellaneous Tariff Revisions

The Company is proposing several miscellaneous tariff revisions that are primarily of a housekeeping nature. Tariff language changes have been proposed to improve ease of customer understanding and administration. Additionally, certain tariff changes are being proposed to address conditions of which there are very limited applications.

EXECUTIVE SUMMARY

Robert J. Mill

Director, Regulatory Policy and Planning

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The purpose of my direct testimony is to discuss several rate design initiatives that AmerenUE is putting forth in this filing. The following are the principal points of my testimony:

(1) AmerenUE has a long standing practice of providing assistance and tools to municipalities, county and regional entities to help them promote their locale to business development. An important aspect of our support has included rate incentives to businesses that locate or expand operations within the AmerenUE service area. In the long run, the ability to attract and to retain large customers benefits not only AmerenUE and its customers, but also provides jobs and tax base for the communities in which we serve. I am introducing two new economic development tariffs that demonstrate our continued commitment to this effort: the Economic Development and Retention Rider (EDRR); and the Economic Re-development Rider (ERR). The EDRR allows AmerenUE to discount certain rates to compete for load of new or expanding customers, and to offer incentives to retain load of an existing customer with plans to move substantial operations out of Company's service area. The EDRR tariff specifies its applicability, terms and conditions. The purpose of Rider ERR is to encourage re-development in defined areas inside the city of St. Louis (City), the boundaries of which are specifically defined in the Rider ERR tariff. These areas were selected due to

AmerenUE having underutilized electric facilities in place capable of serving additional load and the City's desire to spur economic development within these same locations. ERR provides favorable terms for a developer requiring AmerenUE to relocate its existing facilities interfering with a new development and provides a customer occupying the re-developed property a discount from standard rates. ERR applicability, terms and conditions are specified in the tariff.

(2) I am also sponsoring an Industrial Demand Response Pilot Program (IDR) to assess whether industrial process customers are able to respond to load curtailments called by the Company in exchange for a lower monthly demand charge and compensation for avoided energy usage. We are limiting the availability the IDR to no more than five (5) customers with a total demand response aggregated load of 100 MW.

(3) Finally, I introduce a tariff for a Voluntary Green Power Program (VGP). This program is optional for those customers that want to financially support the further development of renewable energy. This program is based on the purchase and retirement of Renewable Energy Certificates (RECs), and not the delivery of the renewable energy commodity to the customer or even to the AmerenUE system. This tariff is applicable to any AmerenUE customer.

EXECUTIVE SUMMARY

Philip Hanser

Principal, The Brattle Group

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The purpose of my direct testimony is to discuss two separate issues in support of some of AmerenUE's rate design proposals. First, I discuss AmerenUE's proposal to stabilize residential rates by limiting the residential rate increase to no more than ten percent (10%) in this case. Second, I discuss the merits of the Company's proposed riders from an economic perspective.

Limiting the residential class rate increase to no more than 10% is reasonable in this case. First, the maximum actual impact of a full 10% residential rate increase will, on net, yield a 3.4% increase in the nominal price of electricity that consumers face since the last rate settlement in 2002. This is less than the increase in prices for the typical market basket of goods in St. Louis over the last four years. The price of the St. Louis consumer's typical market basket of goods was up 10.1% from 2002 to 2005, and is expected to increase an additional 3.1% between 2005 and 2006. Thus, electricity will continue to be relatively cheaper than other goods. Second, nominal hourly wages have increased by 6.9% from 2002 to 2005 and can reasonably be expected to rise 2% to 3% from 2005 to 2006. As a result, electricity will likely continue its trend as a smaller share of consumers' budgets. Third, the proposed increase is significantly less than the increase in the so-called core components of the consumer market basket underlying the CPI, reinforcing the conclusion that the proportion of consumers' total budgets that will likely be spent on electricity will continue to fall. Fourth, the proposed cap is a significantly smaller increase than consumers face for other energy resources in Midwest urban areas since 2002. From 2002 to 2005 in Midwest urban areas, gasoline prices rose 59.9%, fuel oil prices rose 94.6%, and natural gas prices increased 71%. Needless to say, these prices have continued to rise since 2005. Thus, electricity as part of the consumer's energy budget will likely shrink. Finally, for the period January 2002 to June 2005, the average increase in residential rates in non-restructured states and across the entire United States were 13% and 11%, respectively, which implies the proposed increase is roughly one-quarter of the residential rate increases in other non-restructured states and less than one-third of the residential rate increase across the entire United States. As residential rates across the United States in the first quarter of 2006 are already 12% higher than they were a year ago, the disparity between AmerenUE's rates and that of the rest of the country is even larger even with the proposed rate cap.

Two of the rate riders, the Economic Re-development Rider, and the Economic Development and Retention Rider, are "economic development" or "business incentive" rates available to customers on AmerenUE's non-residential tariffs. Their short run goal is attracting new load or new customers or retaining existing loads with very specific characteristics. In the long run, the goal is to increase both employment within the AmerenUE service area and utility revenues, thus enhancing regional income and offsetting fixed costs that would be borne by other customers. They are subject to significant limitations on customer eligibility that preserve ratemaking equity while still affording AmerenUE the opportunity to attract new load under certain defined circumstances. These restrictions include limiting such rates only to industrial customers with very specific characteristics, enforcing maximum terms that require customers to execute contracts prior to December, 2008, and requiring customer participation in specific economic development programs, and/or locations in specifically designated economic development zones.

The third rider is an Industrial Demand Response Pilot which is a “test the waters” pilot demand response program for industrial customers. Such rates are very common throughout the U.S. and are encouraged by regional transmission organizations. AmerenUE joins many other utilities in their exploration of the potential for customer participation in addressing resource needs.

EXECUTIVE SUMMARY

Michael Adams

Director in the Energy Practice
Navigant Consulting, Inc.

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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 NCI 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 ratemaking 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

Richard Voytas

Manager of Corporate Analysis

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The purpose of my testimony is to describe the methodology used to estimate the impact of weather on sales for the test year. I also sponsor the submission of schedules showing the monthly weather normalized sales for each rate class.

Weather normalized sales are used by the Rate Department to normalize both billing determinants and revenues. The Operations Analysis department uses monthly weather normalized sales to estimate normalized production costs. Regulatory Accounting uses the normalized KWH sales adjusted for losses back to the generator to calculate the variable allocation factor.

Issues in prior rate cases that affected the calculation of the impact of weather on sales included the source of historical temperatures necessary to calculate normal weather and the methodology used to calculate normal weather. We believe that neither of these past issues will be issues in this rate case. The temperature database used to calculate normal weather is exactly the same temperature database, complete with adjustments to account for changes in temperature recording instrumentation and equipment location, as agreed to by Staff and AmerenUE in Case No. EM-96-149. The methodology used to calculate normal weather is the Staff's stated preferred rank and average methodology.

Directionally speaking, we show that for the test year ending June 30, 2006, summer weather was approximately 30% higher than normal which would appear to indicate a negative adjustment to actual sales to account for the impact of weather. Winter weather, on the other hand, was approximately 15% below normal which would appear to indicate a positive adjustment to actual sales to account for the impact of weather. However, since summer sales are greater than winter sales the expectation is for an overall negative adjustment to sales, which is consistent with the results of my analysis.