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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EC-2002-1

REBUTTAL TESTIMONY

OF

MARK NEWTON LOWRY

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

Exhibit No. 127
Date 7/10/02 Case No. EC-2002-1
Reporter KEM

St. Louis, Missouri
May, 2002

REBUTTAL TESTIMONY

OF

MARK NEWTON LOWRY

CASE NO. EC-2002-1

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 22 East Mifflin Street, Suite 302, Madison, Wisconsin, 53703.

Q. By whom and in what capacity are you employed?

A. I am a Partner of Pacific Economics Group, LLC ("PEG").

Q. Please describe Pacific Economics Group.

A. Pacific Economics Group (PEG) is an economic consulting firm with practices in the fields of utility regulation and litigation. We have offices in Pasadena, California and Madison, Wisconsin. Five principals of the company are PhD economists and four have served on faculties of respected universities. Founding partner Charles Cicchetti holds the Jeffrey Miller Chair of Government and the Economy at the University of Southern California. He was previously chair of Wisconsin's Public Service Commission and an economics professor at the University of Wisconsin. Founding partner Jeff Dubin is an economics professor at Cal Tech.

PEG is a leading provider of energy utility performance measurement and incentive regulation services. Our personnel have over 30 man years of experience in these areas. We pioneered the use of rigorous statistical benchmarking in U.S. energy utility regulation. This work has required a thorough command of energy industry data and the science of performance measurement.

Q. Please describe your personal qualifications.

A. I am the managing partner in PEG's Wisconsin office. In that capacity, I direct our North American practice in the areas of incentive regulation, performance measurement, industry cost structure issues, and competitive codes of conduct. My specific duties include the supervision of our performance research, the design of incentive regulation plans, and expert witness testimony.

Over the years I have prepared numerous utility performance studies. I have also worked to develop many incentive regulation plans. I have testified or filed commentary sixteen times on energy utility performance issues and twelve times on other incentive regulation issues. The venues for this testimony have included California, Hawaii, Kentucky, Maine, Massachusetts, Oklahoma, New York, and British Columbia.

Before joining PEG, I worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of the Regulatory Strategy practice. In total, I have over twelve years of consulting experience in the areas of performance measurement and incentive regulation.

My career has also included work as an academic energy economist. I have served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. My academic research and teaching stressed the use of mathematical theory and advanced empirical methods in market analysis.

I hold a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin-Madison. I have served as a referee for several scholarly journals and have an extensive record of professional publications and public appearances. My resume is attached to this testimony as Schedule 1.

Q. What is the purpose of your testimony?

A. My testimony presents evidence on the efficiency of AmerenUE ("UE" or "the Company") during its two experimental alternative regulation plans ("EARPs"). Staff maintains in its February 1, 2001 report on the EARPs that an important factor in determining their success is whether UE improved the efficiency of its operations, but claim that it is impossible to evaluate that efficiency. I disagree, and have supervised research on this issue. We examined UE's operations under the EARPs using scientific methods for performance measurement. The improvement in the Company's performance during the EARPs was assessed along with its performance level in the later years of the EARPs. My testimony also includes some remarks on the desirability of continuing incentive regulation for UE.

Q. How is your testimony organized?

A. I first discuss the science of performance measurement. Next, I describe my performance research for UE. I conclude my testimony with comments on incentive regulation. An **Executive Summary** is attached as Appendix A. Further details of my research for Ameren are contained in the report that is attached as Schedule 2.

Efficiency Concepts and Measures

Q. Please provide an overview of the science of performance measurement.

A. Economists have had a long-standing interest in the measurement of enterprise performance. The result has been an evolving science of performance measurement. The research has encompassed both empirical techniques and an appropriate theoretical foundation. The end result is that scientific performance measurement methods have been developed and are in regular use. These methods are available to appraise UE's performance under the EARPs. Research on the performance of electric utilities is also facilitated by the extensive data available on their operations.

Q. Please explain the general approach to performance measurement that you used in your study.

A. The method we employed was econometric cost benchmarking. An econometric cost model relates the cost of a company to business conditions that affect its cost of service. Examples of such conditions are the scale of a company's operations and the prices it faces for labor, capital, and other production inputs. The impact of business conditions on cost is quantified using historical data. Quantitative estimates of these cost "drivers" can be combined with data on the exact business conditions facing a specific utility to generate a benchmark for its costs. Benchmarks can be developed for both the level of cost at a point in time and for the trend in cost over time. Comparing the company's actual costs to these benchmarks yields measures of its efficiency. Techniques used in such a study are well established in the scholarly literature and widely used in scientific research.

Q. What are the advantages of econometric cost modeling in performance measurement?

A. The total cost of a utility is the basis for its revenue requirement under traditional regulation. It is therefore very relevant to the welfare of utility customers. The focus on total cost also permits us to draw on the mathematical theory of cost to identify appropriate business condition variables and their likely cost impact.

Additionally, statistical tests can be used to ensure that business conditions included in the model are significant cost drivers. An econometric cost benchmarking model is thus the result of transparent, rational procedures and not a "black box" that frustrates careful scrutiny.

The econometric approach to evaluating performance is also easier to tailor to the specific circumstances of a utility than alternative methodologies. It is often difficult to choose a peer group that faces business conditions that are highly similar to those of the subject utility. Econometrics permits us to use data from utilities in diverse circumstances to quantify the effects of business conditions on cost in the general case. In fact, a greater diversity of business conditions among the sampled utilities actually enhances the precision of model predictions. The evaluation of the subject utility is subsequently conducted using the exact business conditions that it faces.

<u>Details of the Econometric Research</u>

Q. Please explain how this general methodology was used to appraise UE's performance during the EARPs.

A. We developed mathematical models of the relationship between the total cost of bundled power service and an array of business conditions that utilities face. One model was used to assess UE's cost trend during the EARPs. Another was used to assess UE's recent cost level. The parameters of these models were estimated statistically using historical data on the costs of U.S. electric utilities and the business conditions they faced. The performance of UE was evaluated by comparing the level and trend of its actual cost during the EARP years to those predicted by our cost models given the business conditions in the Company's service territory. The level of UE's cost was evaluated over the 1999-2001 period. The trend in its cost was evaluated over the full 1995-2001 period covered by the EARPs.

Q. Why were separate models required for the trend and levels research?

A. The procedure that we use to estimate the relationship between cost and business conditions in a levels appraisal does not permit the inclusion of a trend variable in the model. Such a variable is designed to capture the tendency of costs to decline over time absent output growth and input price inflation. Such a variable is irrelevant in the appraisal of UE's recent cost level but is very relevant in an appraisal of its cost trend.

Q. Are the cost models that result from your research sensible?

A. Yes. All variables included in the models were found to be significant cost drivers. The estimated cost impacts of the business condition variables also passed a reasonableness assessment. For example, the cost of service was found in both models to be higher the larger was a utility's scale of operation. Cost was also found to be higher the higher were the input prices that utilities faced and the lower were their load factors. In the model that we developed to assess the cost trend of UE, we also found a utility's cost to be significantly higher the greater was the extensiveness of its distribution system and the undergrounding of its power delivery system and the smaller was its diversification into gas distribution and its reliance on hydroelectric self-generation for power supply. The trend variable was found to be statistically significant.

Q. Please describe the data used in your research.

A. All data used in the study were obtained from respected public sources. The primary source of the cost and quantity data was the Federal Energy Regulatory Commission (FERC) Form 1. Major U.S. investor-owned electric utilities are required by law to file this form annually. Cost data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Reporting is thus standardized across utilities.

Supplemental data sources were used primarily for input prices. For example, data on construction costs were obtained from Whitman Requardt and Associates and R.S. Means and Company. Data on the cost of funds were obtained from the U.S. Department of Commerce, and data on the prices of generation fuels were obtained from FERC Form 423.

Q. What was the sample period for your research?

A. The sample period for the cost level research was the 1998-2000 period. The sample period for the cost trend research was 1995-2000. Since data are not as yet available for most sampled utilities for 2001, these are the sample periods that correspond most closely to our cost model predictions for UE.

Q. What companies are represented in your sample?

A. Our full national sample comprised quality data for UE and 77 other U.S. utilities. Many of the sampled companies have been able to operate for extended periods in recent years without a rate case. This strengthened their performance incentives. It was consequently challenging for UE to outperform the benchmark represented by our sample.

Q. Why were nationwide data used in the econometric study?

A. As noted above, the precision of econometric cost research benefits from the largest and most varied sample available. Econometric models control for a wide range of business conditions that affect utility cost. Accordingly, there is no need to limit the sample to companies that faced conditions that were highly similar to those facing UE over the period. There is, in any event, no reason to expect that the efficiency standard for our full national sample is any less demanding than that of a sample from UE's region.

Q. Can an EARP affect a utility's cost efficiency, as measured using an econometric cost model?

A. Yes. By creating stronger incentives to control costs, EARPs can reduce a company's costs relative to those expected for other utilities facing the same business conditions. This will increase the difference between the utility's actual cost and that predicted by an econometric model. It will also slow the growth in cost relative to that predicted by a model.

Q. Can you use your methodology to estimate the cost impact of the EARPs?

A. Yes. The model used to make cost trend predictions captures a wide range of business conditions that cause the cost of a utility to change over time. The difference between the trend in UE's cost and that predicted by the model during the EARP years is then a measure of how the improvement in UE's efficiency compared to the improvement in the efficiency of a typical sampled utility. This difference reflects in turn the difference in the performance incentives faced by UE and the other utilities.

Q. What are the results of your econometric cost research for UE?

A. We found that over the 1995-2001 period covered by the EARPs UE's actual cost grew 1.68% less rapidly on average than the predicted cost of bundled power service. This is impressive when we consider that the model's growth prediction included the typical downward trend in the cost of sampled utilities. As for the cost level appraisal, the Company's actual cost level was found to be a substantial 14.3% lower than the cost predicted by the model during the 1998-2000 period.

Q. What was the dollar value of the resulting efficiencies?

A. The short answer is that UE's cost would be much higher today were it not for EARPs. To put a dollar value on our findings, we performed a simulation that started with UE's Missouri retail revenue in 1995, at the start of the EARP years. That figure, which was $1.8 billion, was used as a proxy for the cost of Missouri retail electric service in that year. With that initial cost, a 1.68% relative cost savings in 1996 alone would then have a value of around $35,000,000 today. The value of savings in 1997 would be much greater than that in 1996 since the slower cost growth in that year would start from the lower cost base achieved in the previous year. A similar finding would hold true for the later EARP years. The end result of this compounding of efficiency gains is that in the later EARP years UE's annual cost of service would have been approximately $200 million higher than its actual costs had it not been for the performance gains achieved under the EARPs. These $200 million would be in addition to today's cost of service which, as the Company's analysis shows, would already justify a rate increase. A benefit of this magnitude is also consistent with the results of our cost level research. The total cumulative difference between actual and predicted cost over the six EARP years was more than $700 million in 2001 dollars.

These savings would grow substantially should the trends established under the EARP program continue. For example, given a similar trend in UE's actual cost and a similar cost growth differential during the next six years, the margin between actual and predicted cost since 1995 would accumulate to over $3 billion in 2001 dollars for the full twelve year period. While the Commission may not be inclined to approve such a lengthy continuation of the EARP program at this time, I believe that such projections are very useful when assessing whether to approve a multiyear extension of the EARP program.

Q. Does your econometric research encompass all benefits of Ameren's recent cost performance level?

A. No. An example of a performance dimension that is not covered is fuel price performance. UE produces large quantities of power using coal-fired generation. It has tried hard to switch to the consumption of lower cost coals and to purchase coals on lower-priced spot terms. Our econometric cost model takes the resultant low price per MMBTU of coal that Ameren consumes as a given despite the expense and risk that have been involved in making this transition.

Empirical Work Conclusions

Q. What conclusions do you draw from research on the cost performance of UE?

A. Our research revealed that AmerenUE made impressive efficiency gains under the EARPs. During the first six years of operation under the EARPs, UE's cost grew considerably more slowly than that predicted by an econometric model that factored in the efforts of sampled utilities to contain cost growth. Thus, the pace of UE's cost performance improvement was unusually rapid during the EARP years. These results support the conclusion that UE operated under stronger performance incentives during the EARPs than other U.S. utilities and that UE's cost of service would be considerably higher in the absence of the EARPs. The trend results would have been less salutary had

UE not also achieved a good performance level during the EARP years. In fact, however, using two established methods, we found that UE's performance level was quite impressive in the later EARP years.

Q. Are you aware of any specific actions by UE that may have improved its efficiency while it was under the EARPs?

A. Yes. I have interviewed a number of Company officials regarding UE's operations during the EARP years. I have, additionally, read a number of company reports and other background materials. I came away with considerable respect for UE's efforts to improve its performance. As discussed further by other witnesses, UE has during the EARP years instituted incentive compensation plans for its employees; earned recognition for the efficient operation of its Callaway nuclear plant; lengthened outage cycles, improved heat rates, and reduced staffing at its coal-fired plants; developed sophisticated gas procurement practices; merged with a neighboring utility; and upgraded its bulk power marketing program. While I have not quantified the individual impact that any of these actions had on UE's efficiency, they support the conclusion that the EARPs encouraged changes in Company behavior that improved its efficiency.

Q. Did UE achieve its superior cost efficiency at the expense of other performance criteria, such as service quality or environmental stewardship?

A. No, quite the contrary. As discussed further by other witnesses, UE has made major efforts to reduce its sulfur dioxide and nitrogen oxide emissions and ranks highly in customer satisfaction. I feel that Ameren also deserves credit for the commitment that it has shown to the city of St. Louis through such decisions as the location of its corporate headquarters. The Company could have a base of operations in many locations and chose downtown St. Louis. Other utility companies have chosen to relocate their headquarters to suburban areas of their service territory or, as in the case of SBC, even to distant states.

Regulation that Fosters Continued Efficient Behavior

Q. What type of regulatory system do you believe will continue to foster efficient behavior by UE and benefits to UE's customers?

A. Like many economists, I believe that utility regulation should simulate competitive market conditions. I have testified on this principle in numerous proceedings. Traditional cost of service regulation, with its focus on the control of a company's earnings, rarely achieves this goal. Incentive regulation can do a better job of simulating competitive markets.

Q. Please explain.

A. Economists believe that competition is generally the most desirable form of market organization. While extolling its benefits, they recognize that some products in our economy can be most efficiently provided by exclusive franchises on terms subject to government regulation. This arrangement is an effective surrogate for competition if competitive market outcomes are realized. The use of utility regulation to simulate competition may be called the competitive market paradigm. Dr. James C. Bonbright expressed the paradigm this way in a classic text four decades ago:

> Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the forces of market competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute.[1]

[1] James C. Bonbright, *Principles of Public Utility Rates* (1961, Columbia University Press), p. 93.

Under competition, prices reflect industry supply and demand conditions and not the actions of individual market participants. Individual suppliers therefore keep all of the after tax dollars from their efforts to contain costs and develop market-responsive price and product offerings. Strong incentives thus exist to slow unit cost growth. Good performance is also encouraged by the freedom suppliers enjoy to choose effective operating practices.

In the long run, competition drives prices to reflect the efficiency of typical suppliers operating with strong performance incentives. The benefits of the industry's slow unit cost growth are thus shared with customers in the form of slow price growth. Prices that reflect industry cost conditions encourage cost-effective consumption. Competitive markets thus promote economic efficiency and share its benefits with customers.

Prices reflecting the efficiency of typical competitive market suppliers may be said to embody a competitive market standard. In competitive markets, suppliers with comparable efficiency can earn a competitive rate of return. Suppliers with superior efficiency can earn a superior rate of return.

Q. Please discuss the degree to which traditional, cost of service rate regulation fulfills the competitive market paradigm.

A. Traditional rate regulation generally does not do the best possible job of simulating competition. In the opinion of many economists, the root cause of this problem is the high cost that must be incurred for regulators to identify rate and service offerings that reflect competitive market standards. It is difficult even for experienced utility managers to recognize the best cost containment and marketing practices. The investigations needed to identify competitive standards would involve considerable cost for regulators, consumer representatives, and the subject utilities.

Measures are understandably taken to contain regulatory costs. One is to control earnings. A second is to discourage utility practices that complicate regulatory review. A third is to extend the period between rate cases. Some of these measures reduce utility efficiency.

Q. Please explain how measures to economize on the cost of regulation can reduce utility efficiency.

A. Consider first the consequences of setting rates to control a utility's earnings. Under traditional regulation, it is common for rate adjustments to be undertaken primarily to ensure that utilities earn a competitive rate of return. Utilities that are "overearning", for instance, are often compelled to reset rates so that their revenue requirement matches their cost. Reviews of the prudence of utility practices are held under traditional regulation but penalties are often levied only for practices with conspicuously unfortunate outcomes. There are no penalties for failure to innovate and no counterbalancing bonuses for superior management practices.

If rates reflect a utility's own unit cost rather than a competitive market standard, efforts to improve cost containment or marketing performance then lead to lower rates. This weakens performance incentives. The atrophy of incentives is greater the more quickly benefits of improved efficiency are passed through to customers.

Consider, next, how the discouragement of utility practices that complicate regulation can reduce efficiency. Practices complicating regulation include those that are especially novel or that raise inherently controversial issues such as the allocation of common costs between services. Discouragement of such practices takes many forms. Some may be prohibited outright while others are subject to unusual prudence vigilance.

Measures like these do simplify regulation. Unfortunately, some of the discouraged practices are important potential sources of efficiency gains. The greater chance of prudence reviews for innovative practices combines with the asymmetry of the prudence review process to discourage innovation and risk taking. Innovation, for instance, will eventually lower rates if successful and may result in a sizable disallowance if unsuccessful.

Q. Can any of the measures you cited promote utility efficiency?

A. Yes. An extension of the period between rate cases can promote efficiency. As the length of the period between rate cases increases, utilities benefit more from cost containment and marketing initiatives. This strengthens performance incentives.

Under traditional regulation, an extension of the period between rate cases is commonly achieved by freezing rates. Unfortunately, most businesses in our economy cannot survive in the long run without nominal price increases to help offset the earnings impact of input price inflation. That is why we observe inflation in prices of the economy's goods and services. While a few industries have, like the telecommunications industry, generated the truly exceptional productivity growth needed to live with rate freezes in the longer term, the electric utility industry is not one of them.

Rate freezes are also risky for utilities. In the electric power industry, the risk is especially great in the procurement of energy inputs such as generation fuels and purchased power. Prices of energy inputs are characteristically volatile, and higher priced inputs like gas and purchased power are often used to respond to unpredictable fluctuations in demand and base load generation.

Q. What conclusions do you draw from this critique of traditional rate regulation?

A. Regulatory frameworks are needed that better simulate competition. Regulators should seek new ways to improve the performance of electric utilities and to share resultant efficiency gains with customers. The need for new frameworks is especially compelling when competitive pressures increases.

Q. Please explain the incentive regulation approach to utility regulation.

A. Incentive regulation is an alternative to cost of service regulation that relies less on earnings controls to meet the just and reasonable standard under the law. For example, a utility with acceptable rates might be placed under a rate freeze in the knowledge that operation under a freeze is challenging. The term "incentive regulation" results from its ability to produce superior performance using stronger incentives.

Q. Can incentive regulation do a better job of simulating competitive market conditions than traditional utility regulation?

A. Yes, I believe that it can. To the extent that a company's rates are decoupled from its own unit cost, utilities can hope to benefit from efforts to improve cost containment and marketing practices. Inferior returns are expected for inferior performance, while superior performance can be expected to produce superior returns. Incentives to improve performance can therefore be stronger than under traditional regulation. Importantly, the weakening of the link between a company's rates and its own unit cost can also permit regulators to afford utilities greater operating freedom to make performance gains.

Special Advantages of Incentive Regulation In Today's Environment

Q. Please explain why incentive regulation is especially useful in the current operating environment of UE.

A. In this period of increasing competitive pressures, incentive regulation is especially valuable because it better simulates the operating environment of other industry players. Traditional regulation will, by weakening incentives, induce a decline in the efficiency of subject utilities relative to the efficiency of other companies in the business, many of which now operate under incentive regulation and/or competitive market conditions. This was not a concern in the past.

Competition has strengthened the incentives of unregulated firms in the power generation industry. Incentive regulation has strengthened incentives for many utilities. In each case, companies have been encouraged to adopt better cost containment and marketing techniques. Human capital formation has accelerated as a result.

Companies subject to traditional regulation will experience weaker performance incentives and greater operating restrictions than companies facing incentive regulation or actual competition. Human capital formation will be impaired. This will place the affected companies at a disadvantage in the rapidly changing energy services markets of the twenty first century. One expected consequence is reduced success in competitive market ventures. Another is reduced odds for survival as locally-based enterprises.

Consider, by way of example, the situation of a competitor with several years of power generation and marketing experience in Britain. The know-how gleaned from this experience might permit it to pay a premium for a Missouri utility operating under traditional regulation. The reality of this threat is highlighted by a recent acquisition in the neighboring state of Kentucky. There, LG&E Energy was acquired by PowerGen, a company with extensive experience operating in Britain's competitive power markets.

Overseas firms with lengthy incentive regulation experience are also becoming merger and acquisitions aggressors. For example, Scottish Power and National Grid have acquired several major U.S. electric utilities. Both firms have operated under incentive regulation in Britain for years. Scottish Power also has experience in Britain's retail power supply market. The superior efficiency of these firms has been cited as one of the main rationales for their acquisition initiatives.

The relationship between UE's regulatory system and the ability of its parent company to survive and prosper as a Missouri-based company offering good value to customers is not a matter of idle conjecture. UE already operates under incentive regulation and offers good value to its customers. Its parent company has already acquired one regional utility and recently announced its intention to acquire another.

Q. Are there any other challenges facing UE that make incentive regulation appropriate at the present time?

A. Yes. I believe there are at least two challenges on the horizon for UE that strengthen the need for incentive regulation. First, UE must make important decisions about its operations in the next few years. UE must, for example, decide how much new power supply capacity to secure and how much of that capacity should be company-owned or outsourced. It is particularly important to make the best possible capacity choices in a period of energy price volatility like that we are experiencing today. The capacity decisions that UE makes in the next few years could affect its rates for decades.

Management challenges are by no means limited to the energy supply area. In the area of power delivery, UE has an important role to play in the transformation of the transmission industry of the central states. New transmission construction and the proper evolution of transmission system management are keys to the development of long distance power trade and competitive bulk power markets. The power distribution business is always challenging since economic growth in Missouri always requires expansion of the distribution system.

Q. What other special challenges does UE face?

A. Many business conditions that will drive UE's future costs are not likely to be as favorable as those of the recent past. For example, UE faces the prospect of having to make substantial capacity additions to meet demand growth and replace aging plant. The cost of funds and fuel prices may rise. In this environment, a reversion to traditional regulation would have especially damaging incentive consequences because UE would likely be forced to ask for rate relief more frequently. A combination of mounting cost pressures and slackening incentives could have adverse future consequences for ratepayers.

Q. Are there any other factors that favor the adoption of incentive regulation at the present time?

A. Yes. Incentive regulation is a growing trend. In both the U.S. and Canada, traditional regulation has been largely abandoned in favor of incentive regulation in the telecommunications, railroad, and oil pipeline industries. In all three cases, traditional regulation was abandoned as competitive pressures in the industry increased.

Incentive regulation is also becoming more common for gas and electric utilities. Many North American gas and electric utilities operate under formal incentive regulation plans, and quite a few of these are in the Midwest and adjacent reaches of Canada. Examples from the electric utility industry include Edison Sault Electric, Black Hills Power and Light, Mid-American Energy, Otter Tail Power, Northern States Power, and the power distributors of Ontario. Midwestern utilities that have operated under gas distribution incentive regulation include Consumers Energy, Michigan Consolidated Gas, and Union Gas. There have also been many incentive regulation plans for gas supply cost in the Midwest, including those for Alliant, Consumers Energy, Michigan Consolidated Gas, Minnegasco, and NICOR.

Other North American energy utilities operate under informal incentive regulation mechanisms such as extended rate freezes that are part of merger or restructuring proceedings. While these are not always recognized as incentive regulation plans, they nevertheless allow utilities to operate for extended periods without exposure to earnings complaints.

There are few cases where incentive regulation has been abandoned after it was implemented. Most regulators have retained incentive regulation, and there are many instances of one incentive regulation plan succeeding an earlier plan. Indeed, the two EARPs already approved for UE represent an example of one incentive regulation plan following another.

There is also a growing tendency in incentive regulation to encourage utilities to keep a share of plan benefits at the end of the plan period. This can bolster incentives for initiatives involving up front costs to achieve long run gains. Plans approved in Massachusetts, and Victoria, Australia have explicit benefit carry forward provisions. At the extreme, commissions have elected in a number of North American proceedings to have no cost-based true up at the end of the plan period. Some commissions have stated that one objective in approving or retaining incentive regulation is to de-emphasize the role of formal rate cases in regulation. Reverting to traditional regulation can undermine the very incentives that incentive regulation is intended to create.

One example of this posture comes from the Maine Public Utilities Commission. In a review of an alternative form of regulation ("AFOR") for NYNEX-Maine, the Public Advocate filed a Motion with the Commission requesting that this review include a cost of service rate case to establish revenue requirements. The Commission rejected the Motion and found that combining cost of service reviews with incentive regulation was not a desirable policy. A principal reason is

> conducting a revenue requirement proceeding tends to undercut the efficiency incentive. Indeed, knowledge that a revenue requirement proceeding will occur could create conflicting incentives to allow costs to rise toward the end of an AFOR period so that the test year used to establish the revenue requirement and rates will include those costs...We do not agree with the proposition that ratepayers are entitled to all efficiency gains (at the end of an incentive regulation plan); such an approach surely diminishes or eliminates the efficiency incentive.[2]

[2] Maine Public Utilities Commission, Docket No. 99-851, Order on Reconsideration, August 22, 2000.

Q. What are the implications of this discussion for the present rate case?

A. I believe that it is good public policy to permit a utility to keep a share of the benefits of demonstrably superior performance at the close of an incentive regulation plan. Doing so strengthens incentives for long-term performance gains that make possible better terms of service in future years. Importantly, this principle applies whether or not the incentive regulation plan is succeeded by another plan.

Far from entertaining such a measure in its testimony, Staff has to the contrary advocated the full true-up of rates to the Company's current cost of service and taken an aggressive and controversial stance on what that cost of service is. The Commission should recognize that the adoption of Staff's approach would have serious consequences for UE's performance down the road.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission, Complainant,	)	
vs.	)	Case No. EC-2002-1
Union Electric Company, d/b/a AmerenUE, Respondent.	)	

AFFIDAVIT OF MARK NEWTON LOWRY

STATE OF WISCONSIN)
) ss
CITY OF MADISON)

Mark Newton Lowry, being first duly sworn on his oath, states:

1. My name is Mark Newton Lowry. I work at 22 East Mifflin, Madison, Wisconsin and I am employed by Pacific Economics Group as a Partner.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 22 pages, Appendix A and Schedules 1 through 2, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

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

Mark Newton Lowry

Subscribed and sworn to before me this 3 day of May, 2002.

Notary Public

My commission expires:

June 8, 2002

EXECUTIVE SUMMARY

Mark Newton Lowry

Partner of Pacific Economics Group LLC, who directs its North American practice in the fields of utility performance measurement and incentive regulation

* * * * * * * * * *

Economists have worked for decades to develop a science of enterprise performance measurement. Scientific methods resulting from this research are now in regular use. These methods were used to appraise the cost performance of Union Electric ("UE" or "Company") under the EARPs. We found UE's performance improvement to be unusually rapid during the EARP years. UE's cost of service today would be considerably higher in the absence of the EARPs.

<u>Research Methods and Data</u>

Econometric cost models are one of the most useful scientific methods for performance measurement. Contrary to the Staff's apparent view that the "experiment" of the EARPs cannot be evaluated, we employed such models to appraise the cost performance of UE during the years of the EARPS. The models we developed relate the total cost of bundled power service to an array of business conditions that "drive" its cost. Economic theory guided the selection and appraisal of business condition variables. The model was estimated statistically using recent historical data on the costs of U.S. electric utilities and the business conditions they faced. The performance of UE was then evaluated by comparing its actual cost and cost growth to those predicted by our cost models given business conditions in the Company's service territory.

All data used in the study were obtained from respected public sources. Many of the companies in our sample have been able to operate for extended periods in recent years without a rate case. This stimulated their performance incentives. As a consequence, it was challenging for UE to turn in a performance superior to that of the typical firm.

The model used to make cost trend predictions captures a wide range of business conditions that cause the cost of a utility to change over time. The difference between the trend in UE's cost and that predicted by the model during the EARP years is a measure of how the improvement in UE's efficiency compared to the improvement in the efficiency of a typical sampled utility. This difference reflects in turn the difference in performance incentives faced by UE and the others during the EARP years.

Research Results

We found that over the 1995-2001 period during which the EARPs were in effect, UE's actual cost grew 1.68% per year less rapidly than our model's cost growth prediction. We calculated the impact on UE's cost of Missouri electric service of this 1.68% of incremental annual cost savings. We found that cumulatively over the six years of the EARP period, UE's actual cost was below its predicted cost by a total of more than $ 700,000,000. I understand the Company's analysis shows that UE's cost of service has increased to a level which would justify a rate increase. Our econometric research suggests that UE's annual cost of service would be higher by an additional $200 million had it not been for the efficiency gains that the Company has achieved under the EARPs. The conclusion of large cost savings finds additional support from our econometric cost level research, which found UE's actual cost level was a substantial 14.3% below the cost benchmark for 1999 to 2001.

Using well established scientific methods, we have therefore found that the pace of UE's performance improvement was unusually rapid during the EARP years. The results support the theory that UE operated under stronger performance incentives during the EARPs than other U.S. utilities and that UE's costs would have been substantially higher absent the EARPs.

Regulation to Foster Continued Efficient Behavior

My empirical research suggests that the EARPs have had a material impact on UE's cost and can stimulate even larger cost reductions in the future. These findings conform to my general views, based on years of experience in the field, that incentive regulation can work well for utilities and their customers. Like many economists, I believe that utility regulation should simulate competitive market conditions. Traditional cost of service regulation, with its focus on the control of a company's earnings, rarely achieves this goal. Incentive regulation can do a better job of simulating competitive markets.

In this period of increasing competitive pressures, incentive regulation is especially valuable because it strengthens incentives to improve utility performance relative to other firms. Traditional regulation will induce a decline in the efficiency of utility companies relative to the efficiency of firms that now operate under competition or incentive regulation. This also increases the risk of takeover by more efficient companies.

Two other challenges facing UE also increase the need for incentive regulation. First, UE must make important decisions regarding its power supply portfolio and its energy delivery system in the next few years. It is particularly important to make the "right" choices regarding power supply capacity in the present environment of energy price volatility. Decisions that UE makes in the next few years could affect its rates for decades. Strong performance incentives will help UE make the right decisions.

A second concern is that the factors driving UE's cost growth in the next decade are likely to be less favorable than those in the recent past. For example, UE may be forced to make sizable capital expenditures. The cost of funds and energy prices may rise. In this environment, a reversion to traditional regulation would likely force UE to ask for rate relief frequently. This would undermine its performance incentives at a time of increasing cost pressure.

Continuation of the EARP program would permit the Commission to continue its leading role in incentive regulation. Once used primarily overseas and, domestically, in other utility industries, incentive regulation is now widely used to regulate Midwestern energy utilities. Many other energy utilities operate under informal incentive regulation mechanisms such as rate freezes that are part of merger or restructuring proceedings.

There are few cases where incentive regulation has been abandoned after it was implemented. Most regulators that have gone down the path of incentive regulation have stayed on it, and there are many instances of one incentive regulation plan succeeding an earlier plan. There is also a growing tendency in incentive regulation to permit utilities to keep a share of an incentive plan's benefits beyond the plan's term and I recommend that the Commission do so for UE as well. This strengthens incentives for initiatives to improve a utility's long term performance.

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Relevant Work Experience, Primary Positions:

October 1998-Present **Partner, Pacific Economics Group, Madison, WI**

Manages PEG's Madison office. Specific duties include project management and research, written reports, public presentations, expert witness testimony, and marketing. Research specialties include: performance-based regulation, statistical benchmarking, utility industry restructuring, and codes of competitive conduct.

January 1993-October 1998 Vice President
January 1989-December 1992 Senior Economist, Christensen Associates, Madison, WI

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility PBR and statistical benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Teaching and research specialty: analysis of markets for energy products and metals.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects:

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
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39. Edison Electric Institute, July 2000
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41. Infocast, Washington, DC, October 2000
42. Wisconsin Public Utility Institute, Madison, WI, November 2000
43. Infocast, Boston, MA, March 2001
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THE PERFORMANCE OF AMERENUE UNDER THE EARPS

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

Statistical benchmarking has in recent years become widely used in the assessment of utility performance. Managers use benchmarking studies to appraise how well their companies do. Benchmarking also plays a role in modern regulation. Such studies have, for example, been used to assess the reasonableness of costs at the start of multiyear rate plans.

Utility performance studies are facilitated by an extensive scientific literature and the abundant data available on utility operations. However, accurate appraisals are still challenging. There are important differences between companies in the character and scale of demand, the prices of production inputs, and other business conditions that influence their operations. Accurate data are not available for all companies or relevant business conditions.

Pacific Economics Group (PEG) personnel have been active for over a decade in the measurement of utility performance. We pioneered the use of rigorous statistical benchmarking research in U.S energy utility regulation. We have testified on our work in several proceedings.

AmerenUE ("UE" or "the Company") is engaged in a proceeding on the continuation of the Company's experimental alternative regulation plan (EARP) for retail electric service in Missouri. A central issue in the proceeding is the Company's performance over the term of the previous EARPs. UE has commissioned PEG to measure the performance of its electric operations during the EARP years.

This paper is a report on our research. Following a brief summary of the work, Section 2 discusses the data used in the study and our calculation of bundled power service cost. Our econometric work is discussed in Section 3. Additional, more technical details of the study are presented in the Appendix.

1.2 Summary of Research

1.2.1 Definition of Cost

Our research for UE required the calculation of its total cost as a provider of bundled power service. Bundled power service was defined to comprise power generation, procurement, transmission, and distribution. The total cost of service comprised the costs of capital ownership and operation and maintenance activities.

1.2.2 The Sample

Our work was based on a sample of quality data for investor-owned U.S. utilities providing bundled power service. Our full national sample comprised data for UE and 77 other utilities. We excluded data from the many utilities that restructured in the last few years to facilitate retail competition. For a number of the sampled utilities, good performance has been encouraged by their ability to operate for extended periods without a rate case. The efficiency standard posed by the companies in the sample was challenging.

1.2.3 Research Results

The cost performance of UE was appraised using econometric models of bundled power service cost. Guided by economic theory, we developed models in which the total cost of bundled power service is a function of quantifiable business conditions. The parameters of the model were estimated using nationwide historical data on the cost of utilities and the business conditions that they faced. We used one model to benchmark the growth trend of UE's cost during the full 1995-2001 EARP period. The other was used to benchmark the average level of UE's cost given the business conditions it faced from 1999 to 2001. The model used for the cost trend analysis included a trend variable to capture the tendency of cost to fall in the absence of output and input price growth.

The key results of the study are as follows. Over the 1995-2001 period, the growth rate prediction of our model was 1.68% more rapid on average than the growth rate of UE's actual cost. As for the levels appraisal, UE's average annual benchmark cost was found to be 14.3% above its actual cost over the 1999-2001 period.

The results of the growth rate analysis were used to place a dollar value on the difference between actual and predicted cost. Using UE's Missouri electric revenue in 1995 as a proxy for the cost of the corresponding services in that year, we calculate that in the absence of 1.68% average annual cost savings cost would have been over $700,000,000 higher over the six plan years. In the most recent plan years, cost would have been about $200,000,000 higher annually. Our cost level analysis also suggests recent cost savings of this general magnitude. Continuation of these trends over the next six years would produce an accumulated difference between actual and predicted cost over the twelve year period of over $3 billion in 2001 dollars.

1.2.4 Conclusion

In conclusion, our research on the performance of UE as a bundled power service provider during the EARP years employed well-established and scientific performance measurement techniques. UE's recent performance level was considered as well as its performance trend. The performance trend appraisal factored in the extent of normal performance improvements during the EARP years. UE's measured performance was impressive from both perspectives. The results support the view that the EARPs provided stronger performance incentives than those experienced by other U.S. utilities, and that UE was driven by these incentives to make substantial performance gains. UE's cost of service would have been substantially higher today in the absence of the EARPs. We believe that these results merit careful consideration in the Commission's review of the merits of continuing the EARP program.

2. DATA ISSUES

2.1 Data

The primary source of the data used in our research for UE was the Federal Energy Regulatory Commission (FERC) *Form 1*. This form is filed annually by all major U.S. electric IOUs, along with certain non-utility entities that are also jurisdictional to the FERC.[1] Selected *Form 1* data have been published regularly by the U.S. Energy Information Administration (EIA) in a series of publicly available documents that are currently entitled *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*. The data described below are from FERC Form 1 unless otherwise noted.

All major U.S. electric IOUs which filed the FERC *Form 1* electronically in 2000 and which have reported the required data continuously since they achieved a "major" designation were considered for sample inclusion. To be included in the study utilities were required, additionally, to have plausible data and to be vertically integrated as determined by threshold levels of involvement in power generation, transmission, and distribution. Data from UE and seventy-seven other companies met all of these standards. We believe that the data for these companies are the best available to perform scientific research on the efficiency of Ameren's operations. The included companies are listed in Table 1.

2.2 Definition of Cost

2.2.1 Applicable Total Cost

Cost figures played an important role in our performance research. Our approach to calculating cost is therefore quite important. Bundled power service was defined to include power generation, procurement, transmission, and distribution. The total cost of service was

[1] The selection criteria used in determining the major IOU classification is detailed in *Financial Statistics of Major U.S. Investor-Owned Electric Utilities (1993)* EIA page 2.

Table 1

List of Sampled Companies

Company
AmerenUE
AmerenCIPS
Appalachian Power Co (VA)
Arizona Public Service Co
Atlantic City Electric Co
Baltimore Gas & Electric Co
Carolina Power & Light Co
Central Hudson Gas & Electric Corp
Central Illinois Light Co
Central Power & Light Co (TX)
Cleco Corp
Cleveland Electric Illuminating Co (OH)
Columbus Southern Power Co (OH)
Consumers Energy Co (MI)
Dayton Power & Light Co (OH)
Delmarva Power & Light Co
Detroit Edison Co
Duke Energy Corp
Duquesne Light Co
El Paso Electric Co
Empire District Electric Co (MO)
Entergy Arkansas Inc
Entergy Gulf States Inc
Entergy Louisiana Inc
Entergy Mississippi Inc
Florida Power & Light Co
Florida Power Corp
Georgia Power Co
Gulf Power Co
Illinois Power Co
Indiana Michigan Power Co
Indianapolis Power & Light Co
Interstate Power Co
Kansas City Power & Light Co (MO)
Kansas Gas and Electric Co
Kentucky Power Co
Kentucky Utilities Co
Louisville Gas and Electric Co (KY)
Madison Gas and Electric Co (WI)

Company
Maine Public Service Co
Minnesota Power Inc
Mississippi Power Co
Montana-Dakota Utilities Co
Nevada Power Co
Northern Indiana Public Service Co
Northern States Power Co
Northwestern Public Service Co (SD)
Ohio Edison Co
Ohio Power Co
Oklahoma Gas and Electric Co
Orange and Rockland Utilities Inc
Otter Tail Power Co
PacifiCorp
Pennsylvania Electric Co
Pennsylvania Power Co
Portland General Electric Co
Potomac Electric Power Co
PP&L Inc
Public Service Co of Colorado
Public Service Co of New Mexico
Public Service Co of Oklahoma
Saint Joseph Light & Power Co
San Diego Gas & Electric Co
Savannah Electric and Power Co
Sierra Pacific Power Co
South Carolina Electric & Gas Co
Southern Indiana Gas and Electric Co
Southwestern Electric Power Co (LA)
Southwestern Public Service Co
Tampa Electric Co
Texas Utilities Electric Co
Toledo Edison Co
Tucson Electric Power Co
United Illuminating Co
West Texas Utilities Co
Wisconsin Electric Power Co
Wisconsin Power and Light Co
Wisconsin Public Service Corp

defined to include total electric operation and maintenance expenses and the total cost of electric plant ownership.

The study used a service price approach to measure the cost of plant ownership. Under this approach, the cost of plant ownership is the product of a capital quantity index and the price of capital services. The cost of plant ownership includes depreciation, tax payments, the opportunity cost of plant ownership, and capital gains. This method has a solid basis in economic theory and is well established in the scholarly literature. It also controls in a precise and standardized fashion for differences between utilities in the age of their plant. Further details of these calculations are provided in Section A.1 of the Appendix.

2.2.2 Cost Decomposition

Estimation of the cost model involved the decomposition of total cost into four major input categories: capital services, labor services, energy, and materials and miscellaneous other O&M inputs. The cost of labor was defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs was defined to be O&M expenses net of expenses for labor, generation fuels, and power purchases. This residual cost category included expenses for various materials, the services of contract workers, insurance, and real estate and equipment rentals.

3. ECONOMETRIC RESEARCH

3.1 An Overview of the Method

This section provides a substantially non-technical account of the econometric approach to benchmarking employed in this study. A mathematical model called a cost function was specified. Cost functions represent the relationship between the cost of a firm and quantifiable business conditions that it faces. Business conditions are defined as aspects of a firm's operating environment that influence its operations but cannot be controlled.

Economic theory was used to guide cost model development. We posited that the actual total cost ($C_{i,t}$) incurred in year t by utility i is a function of the minimum achievable cost ($C_{i,t}^*$) and an efficiency factor ($efficiency_{i,t}$). Specifically,

$$\ln C_{i,t} = \ln C_{i,t}^* + efficiency_{i,t} . \qquad [1]$$

The term ln here indicates the natural logarithm of a variable.

According to theory, the minimum total cost of an enterprise is a function of the amount of work it performs and the prices it pays for capital and labor services and other production inputs. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, cost is apt to be higher the higher are input prices and the greater is the amount of work performed.

Here is a simple example of a minimum total cost function that is consistent with cost theory:

$$\ln C_{i,t}^* = a_0 + a_1 \ln V_{i,t} + a_2 \ln PF_{i,t} + u_{i,t} . \qquad [2]$$

Here for each firm i in year t, the term $C_{i,t}^*$ is the minimum total cost of service. The variable $V_{i,t}$ is the sales volume of the company. It quantifies one dimension of the work that it performs. The variable $PF_{i,t}$ is the price that the company pays for generation fuel. The fuel price and the sales volume are the measured business conditions in this cost function.

Combining the results of Equations [1] and [2] we obtain the following cost model.[2]

$$\ln C_{i,t} = \alpha_{0,t} + \alpha_1 \ln V_{i,t} + \alpha_2 \ln PF_{i,t} + e_{i,t} \,. \qquad [3]$$

Here the *actual* (not minimum) total cost of a utility is a function of the two measured business conditions. The terms $\alpha_{0,t}$, α_1, and α_2 are model parameters. The $\alpha_{0,t}$ parameter captures the efficiency factor for the average firm in the sample as well as the value of a_0 from the minimum total cost function. The values of α_1 and α_2 determine the effect of the two measured business conditions on cost. If the value of α_2 is positive, for instance, an increase in the fuel price will raise cost.

The term $e_{i,t}$ is called the error term. We assume that it is a random variable. The error term includes the term $u_{i,t}$ from the minimum total cost function. This term reflects errors in the specification of the model, including problems in the measurement of output and other business condition variables. The error term also reflects the extent to which the company's inefficiency factor differs from the sample norm. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as the mean and variance.

A branch of statistical science called econometrics has developed procedures for estimating parameters of economic models. Cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions that they faced. For example, a positive estimate for α_1 would reflect the fact that the cost reported by sampled companies was typically higher the higher was its sales volume.

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[2] Here is the full logic behind this result:

$$\begin{aligned}
\ln C_{i,t} &= \ln C^*_{i,t} + efficiency_i \\
&= \left(a_0 + a_1 \ln V_{i,t} + a_2 \ln PF_{i,t} + u_{i,t}\right) + efficiency_{i,t} \\
&= \left(a_0 + efficiency_t^{norm}\right) + a_1 \ln V_{i,t} + a_2 \ln PF_{i,t} \\
&\quad + \left[u_{i,t} + \left(efficiency_{i,t} - efficiency_t^{norm}\right)\right] \\
&= \alpha_{0,t} + \alpha_i \ln V_{i,t} + \alpha_2 \ln PF_{i,t} + e_{i,t}
\end{aligned}$$

Numerous statistical methods have been established in the econometrics literature for estimating parameters of economic models. In choosing among these, we have been guided by the desire to obtain the best possible model for cost benchmarking. As discussed further in the Appendix, different procedures were chosen for the cost level and cost trend assessments.

Econometric methods are useful in selecting business conditions for the model. Tests are available for the hypothesis that the parameter for a business condition variable equals zero. Variables were excluded from the model when such hypotheses could not be rejected. Thus, all business conditions included in the cost models we used for benchmarking were found to have a statistically significant cost impact.

A cost model fitted with econometric parameter estimates may be called an econometric cost benchmark model. We can use such a model to predict a company's cost given values for the right-hand side variables that represent the business conditions that the company faced. Returning to our simple example, we might predict the (logged) cost of UE in period t as follows:[3]

$$\ln \hat{C}_{Ameren,t} = \hat{\alpha}_{0,t} + \hat{\alpha}_1 \cdot \ln V_{Ameren,t} + \hat{\alpha}_2 \cdot \ln PF_{Ameren,t} \cdot \qquad [4]$$

Here $\hat{C}_{Ameren,t}$ denotes the predicted cost of UE in period t, $V_{Ameren,t}$ is its power sales volume in that period, and $PF_{Ameren,t}$ is the fuel price that it paid. The $\hat{\alpha}_{0,t}$, $\hat{\alpha}_1$, and $\hat{\alpha}_2$ terms are estimates of the parameter values. Notice that in this model the cost benchmark reflects, through the estimate of parameter $\alpha_{0,t}$, the *average* efficiency of the sampled utilities.

If the parameter estimates are unbiased and the expected value of $u_{i,t}$ is zero, the percentage difference between the company's actual cost and that predicted by the model can be shown to equal the difference between the efficiency factor of UE and that of the typical sampled firm. This can be expressed mathematically as

$$\ln\left(C_{Ameren,t} \big/ \hat{C}_{Ameren,t} \right) = \ln C_{Ameren,t} - \ln \hat{C}_{Ameren,t} = efficiency_{Ameren,t} - efficiency_t^{norm}. \qquad [5]$$

This percentage difference is thus a measure of the company's cost performance.

The use of logarithms in an econometric cost model facilitates its use to benchmark the *growth rate* of a company's cost as well as its *level*. Equation [3], for example, implies that

$$ln(C_{i,t} / C_{i,t-1}) = (\alpha_{0,t} - \alpha_{0,t-1}) + \alpha_1 \, ln(V_{i,t} / V_{i,t-1}) + \alpha_2 \, ln(PF_{i,t} / PF_{i,t-1}) + (e_{i,t} - e_{i,t-1}) \qquad [6]$$

In other words, the (logarithmic) growth rate in cost is a function of the growth rates in the values of the business condition variables. Should we fit the model with parameter estimates and the growth rates in the business conditions facing UE, we can then benchmark its cost growth between two years using the formula

$$\begin{aligned} &\ln\left(\hat{C}_{Ameren,t} / \hat{C}_{Ameren,t-1}\right) \\ &\quad = \left(\hat{\alpha}_{0,t} - \hat{\alpha}_{0,t-1}\right) + \hat{\alpha}_1 \ln\left(V_{Ameren,t} / V_{Ameren,t-1}\right) + \hat{\alpha}_2 \left(PF_{Ameren,t} / PF_{Ameren,t-1}\right). \end{aligned} \qquad [7]$$

The growth rate analysis can be extended over as many years as desired.

A number like that generated by the cost benchmark model in [7] constitutes our best *single* guess of the company's cost given the business conditions it has faced. This is an example of a point prediction. An important characteristic of the econometric approach to benchmarking is that the statistical results provide information about the *precision* of such point predictions as well. According to econometric theory, the precision of a point prediction is greater the lower is the variance of the model's prediction error. The variance of the prediction error can be estimated using a well-established formula. The formula shows that the precision of cost model predictions is greater to the extent that:

1) The model is more successful in explaining the variation in cost in the sample.
2) The size of the sample is larger.
3) The number of business condition variables included in the model is smaller.
4) The business conditions of sampled utilities are more varied.

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[3] Since this is a predicted equation using estimated parameters there is no error term.

5) The business conditions of the subject utility are closer to those of the typical firm in the sample.

The estimated variance of the prediction error can be used to assess the precision of best-guess cost predictions. One method for doing this is to calculate a test statistic for the point prediction. This statistic will decline as the estimated variance increases. An equivalent approach is to construct a confidence interval around the point prediction. The point prediction lies at the center of this interval. The confidence interval may be viewed as the full range of cost predictions that is consistent with the sample data at a given confidence level. It is wider the lower is the confidence level and the higher is the estimated variance of the prediction error.

We can use test statistics or confidence intervals to assess the statistical significance of differences between a company's actual and predicted cost. For example, if a utility's actual cost is not within a confidence interval, we may conclude that its actual cost differs significantly from the model's prediction. If its cost is significantly *below* the model's prediction, for instance, we may deem the company a significantly *superior* cost performer.

Econometric cost benchmarking has advantages over alternative approaches to performance measurement. One is the focus on total cost as the performance indicator. A utility's cost is generally a major determinant of its prices and thus is important to customer welfare. A focus on cost also makes it possible to use the economic theory of cost to select business condition variables and assess the plausibility of parameter estimates. A second advantage of econometric cost benchmarking is our ability to use statistical tests to decide which business condition variables are important enough for model inclusion.

Econometric benchmarking also makes possible flexibility in the selection of a sample. Controls for a wide range of business conditions permit us to use data for a large and diverse set of companies. Variation in sampled business conditions is actually welcomed in econometric benchmarking since it helps to make estimates of model parameters more accurate. Suppose, for example, that we want an accurate estimate of α_2, which is intended in our illustrative model to capture the effect of fuel prices on cost. It is then desirable for the sample to include companies facing a wide range of fuel prices. Once parameters are estimated, the model is fitted with the exact business conditions faced by the subject utility.

The availability of scientific hypothesis tests for model predictions is a fourth advantage of our econometric method. Approaches based solely on point predictions can create a false sense of precision. In fact, we should not be surprised if available data do not permit us to identify a great many significantly superior performers with a high degree of confidence.

3.2 Business Condition Variables

3.2.1 Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There were two output quantity variables in our cost model: a sales volume index and the number of retail customers served. The value of the sales volume index was a weighted average of the values of subindexes for the volumes of power sales to residential, other retail, and sales for resale customers. The shares of each market category in total power sales revenue were used as weights. All data used to construct these variables were drawn from FERC Form 1. We expect cost to be higher the higher are the values of both of these output quantity variables.

3.2.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified input price variables for capital, labor, energy, and other O&M inputs.[4] We expect cost to be higher the higher are the values of each of these price variables.

The labor price variable used in this study was the utility's own salaries and wages per employee. The data needed to compute this variable are reported on FERC Form 1. The price of energy was measured by indexes that featured separate price subindexes for coal, residual

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[4] The price for other O&M inputs does not appear in the estimated parameter tables due to the imposition of the linear homogeneity restriction predicted by economic theory.

fuel oil, natural gas, and bulk power. The growth rate in the energy price index used in the trend analysis was, for example, a weighted average of the growth rates of the four price subindexes. The generation fuel prices were costs per MMBTU obtained from FERC Form 423.

Prices for other O&M inputs were assumed to be the same in a given year for all companies. They were escalated by the gross domestic product price index. Our approach to the computation of a price index for capital services is described in Section A.1 of the Appendix.

3.2.3 Other Business Conditions

One additional business condition variable was included in both cost models. That was the load factor, which is a measure of load peakedness. This variable was computed as the ratio of the hourly average relevant delivery volume to the peak load. The required data were drawn from FERC Form 1. We would expect a company's cost to be higher the lower was its load factor.

Five business condition variables appear in the econometric model for cost trend appraisal that do not appear in the model for the cost level appraisal.[5] One was the percentage of electric distribution plant in the gross value of gas and electric distribution plant. This variable was intended to capture the extent to which a company had not diversified into gas distribution. Diversification of this kind can lower cost due to the realization of scope economies. We therefore expect cost to be higher the higher is the value of this variable.

The second variable that was added to the cost trend model was the percentage of generation that was not hydroelectric. Hydroelectric generation is generally less expensive than other kinds of generation. We therefore expect cost to be higher the greater is the value of this variable.

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[5] Four of these variables were considered for inclusion in the econometric model used for levels comparisons but were not found to be statistically significant. The trend variable could not be considered due to the estimation procedure.

The third variable that was added to the cost trend model was the percentage of the gross value of transmission and distribution (T&D) plant that was for overhead rather than underground facilities. We would expect cost to be lower the higher was this percentage since overhead systems are typically less costly to construct than underground systems. The fourth variable was the miles of overhead T&D line. We included this as a measure of the geographical extensiveness of the power delivery system. We expect cost to be higher the greater are the miles of line.

The fifth business condition variable that was added to the cost model used for trend appraisal was a trend variable. This variable captures any trend in the cost of sampled utilities that was independent of the trends in other included business conditions. We would not be surprised to find a negative value for the trend variable parameter which reflects efficiency trends in the industry.

3.3 Econometric Results

3.3.1 Estimation Results

Estimation results for the cost models are reported in Tables 2 and 3. Since mean-scaled data were used in the estimation process, the parameter values for the first order terms of the translogged variables are elasticities of cost at the sample mean with respect to the basic variable.[6] The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The tables shade the results for these terms for reader convenience. The parameter estimates for the other business condition variables (which were not translogged) are also estimates of cost elasticities at sample mean values of the variables. The tables report as well the values for the test statistics corresponding to each parameter estimate. These were also generated by the estimation program. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected using the corresponding statistic.

[6] The translogging of variables is discussed in the Appendix.

Examining the results in Table 2, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. The coefficients for the first order terms of the translogged variables and of the additional business condition variables were all statistically significant. Cost was found to be higher the higher were the input prices and output quantities. At the sample mean, a 1% increase in the sales volume index raised cost by 0.632%. A 1% increase in the number of customers served raised cost by 0.311%. The elasticities of cost with respect to the prices of capital, energy, and labor inputs were 0.487%, 0.293%, and 0.093%. These results highlight the capital and energy intensive character of bundled power service technology. Table 2 also shows that cost was higher the lower was the load factor, the diversification into gas distribution, and the reliance on hydroelectric generation and the greater were the miles of power line. The trend variable parameter had a value of -0.017. This suggests that the cost of sampled utilities tended to fall by about 1.7% in the absence of demand growth and input price inflation. Turning to Table 3, it can be seen that results for the econometric model used in the cost level appraisal were broadly similar to those for the model used in cost level appraisal for the variables that appear in both models.

3.3.2 Benchmarking Results

Table 4 and Figures 1 and 2 present the results of our appraisals of the cost of UE using the econometric models. UE's cost was predicted by our model to grow 1.68% more rapidly than actual cost on average during the 1995-2001 period during which the EARPs were in effect. This difference was statistically significant at a 99% confidence level. As for the cost level appraisals, UE's average benchmark cost during the 1999-2001 period was found to be 14.3% above its actual value. This difference was statistically significant at an 84% confidence level.

3.3.3 Valuation of the Cost Savings

The value of the cost growth slowdown achieved by Ameren during the EARP years is calculated in Table 5. Here, we take Ameren's 1.8 billion dollars of Missouri electric revenue in 1995, at the start of the EARPs, as a proxy for the cost of the corresponding services.[7] We then escalate this cost by the actual growth in its cost over the 1995-2001 period as we have computed it for purposes of our benchmarking work. This cost was then compared with the cost resulting if it grew 1.68% more rapidly each year.

Intuition suggests that the difference between the predicted and the actual cost should be sizable. After all, if UE's actual cost grew 1.68% more slowly in 1996, the value of the difference in that year alone would be over $ 30,000,000. If the same thing occurred in 1997, the cost saving would be much larger since the slow cost growth in 1997 would start from the lower base achieved in 1996. That is, the difference between actual and predicted cost would compound with the additional EARP year. Analogous results would hold for the later EARP years.

Table 5 shows the impressive consequence of this compounding. In the later EARP years, UE's predicted cost was around $ 200 million higher than its actual cost. A figure of this general magnitude is supported by our cost level research as well. The accumulated difference between predicted and actual cost over the six EARP years was more than $ 750 million in 2001 dollars. The difference between predicted and actual cost would be much higher were the trends established between 1995 and 2001 to continue for another six years. The table shows that the accumulated difference between the predicted and actual cost over the full twelve year period would be over $3 billion 2001 dollars.

[7] It is best not to use Ameren's actual cost as we measure it for benchmarking purposes since this makes use of a capital costing method that differs from that which is sued to set rates.

Table 2

VARIABLE KEY

L = Labor Price
K = Capital Price
E = Energy Price
N = Number of Retail Customers
VX = Volumetric Index
LF = Load Factor
%E = Percent that is Electric in Total Value of Gas and Electric Plant
M = Miles of Overhead Line: T&D
%O = % Overhead in total T&D Plant
%H= Percent of Net Generation that is not Hydroelectric
T = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.093	62.349
LL	0.055	7.733
LK	-0.044	-5.862
LE	-0.043	-7.533
LN	0.032	6.394
LVX	-0.033	-7.276
LLF	0.047	3.801
K	0.487	131.653
KK	0.160	10.460
KE	-0.134	-10.855
KN	0.017	1.445
KVX	0.006	0.532
KLF	-0.112	-3.673
E	0.293	57.760
EE	0.165	9.371
EN	-0.056	-3.409
EVX	0.032	2.135
ELF	0.030	0.710
N	0.311	9.904
NN	0.276	2.664
NVX	-0.321	-3.155
NLF	-0.606	-3.075

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
VX	0.632	22.741
VXVX	0.368	3.592
VXLF	0.380	2.178
LF	-0.309	-3.938
LFLF	-1.510	-2.202
%E	0.153	2.876
M	0.062	3.799
%O	-0.115	-2.666
%H	0.657	2.269
T	-0.017	-4.909
Constant	21.157	2309.301
System Rbar-Squared	0.994	
Sample Period:	1995-2000	
Number of Observations	404	

Table 3

Econometric Results For the Cost Level Research

VARIABLE KEY

L = Labor Price
K = Capital Price
E = Energy Price
N = Number of Retail Customers
VX = Volumetric Index
LF = Load Factor

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.082	26.217
LL	0.074	4.594
LK	-0.063	-3.245
LE	-0.058	-4.564
LN	0.026	2.379
LVX	-0.031	-3.065
LLF	0.084	3.094
K	0.477	59.639
KK	0.234	5.592
KE	-0.143	-4.672
KN	0.016	0.583
KVX	0.004	0.154
KLF	-0.162	-2.328
E	0.309	29.030
EE	0.206	4.925
EN	-0.055	-1.543
EVX	0.035	1.056
ELF	0.097	1.060
N	0.237	4.036
NN	-0.131	-0.491
NVX	0.005	0.019
NLF	-0.578	-1.219

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
VX	0.769	13.218
VXVX	0.119	0.484
VXLF	0.252	0.614
LF	-0.502	-3.035
LFLF	0.169	0.127
Constant	21.210	1032.553
System Rbar-Squared	0.994	
Sample Period:	1998-2000	
Number of Obsevations	78	

Table 4

Actual and Predicted Cost Levels and Growth Rates For AmerenUE

Cost Level

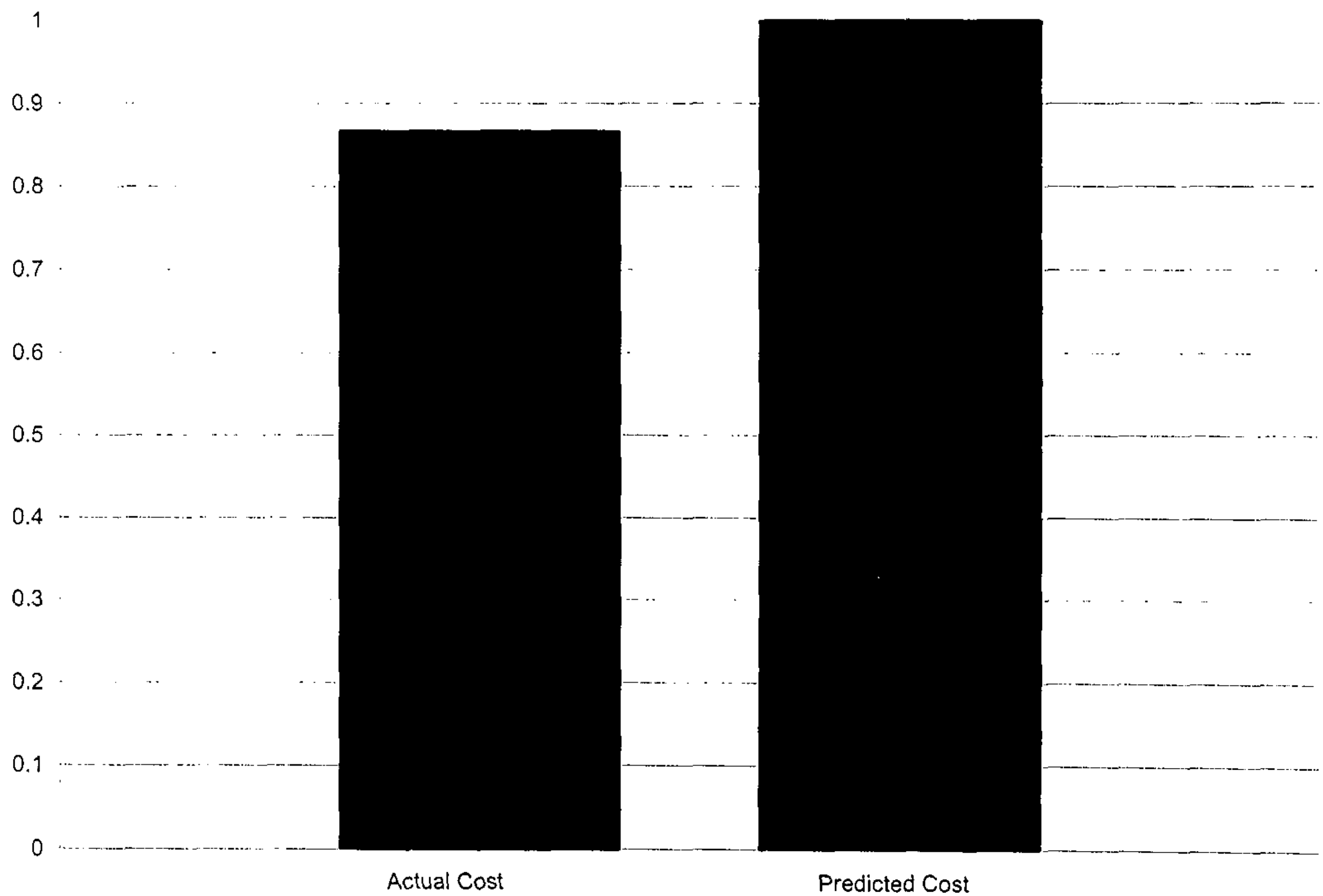
Actual Cost $1,000	Predicted Cost $1,000	Difference (%)	t-statistic
0.867	1.00	-14.3%	-0.980

Growth Rate of Cost

Actual Growth Rate	Predicted Growth Rate	Difference (%)	t-statistic
1.09%	2.76%	-1.68%	-32.906

Figure 1

Actual and Predicted Cost Indexes For AmerenUE



Schedule 2-22

Figure 2

Actual and Predicted Growth Rates of Cost For AmerenUE

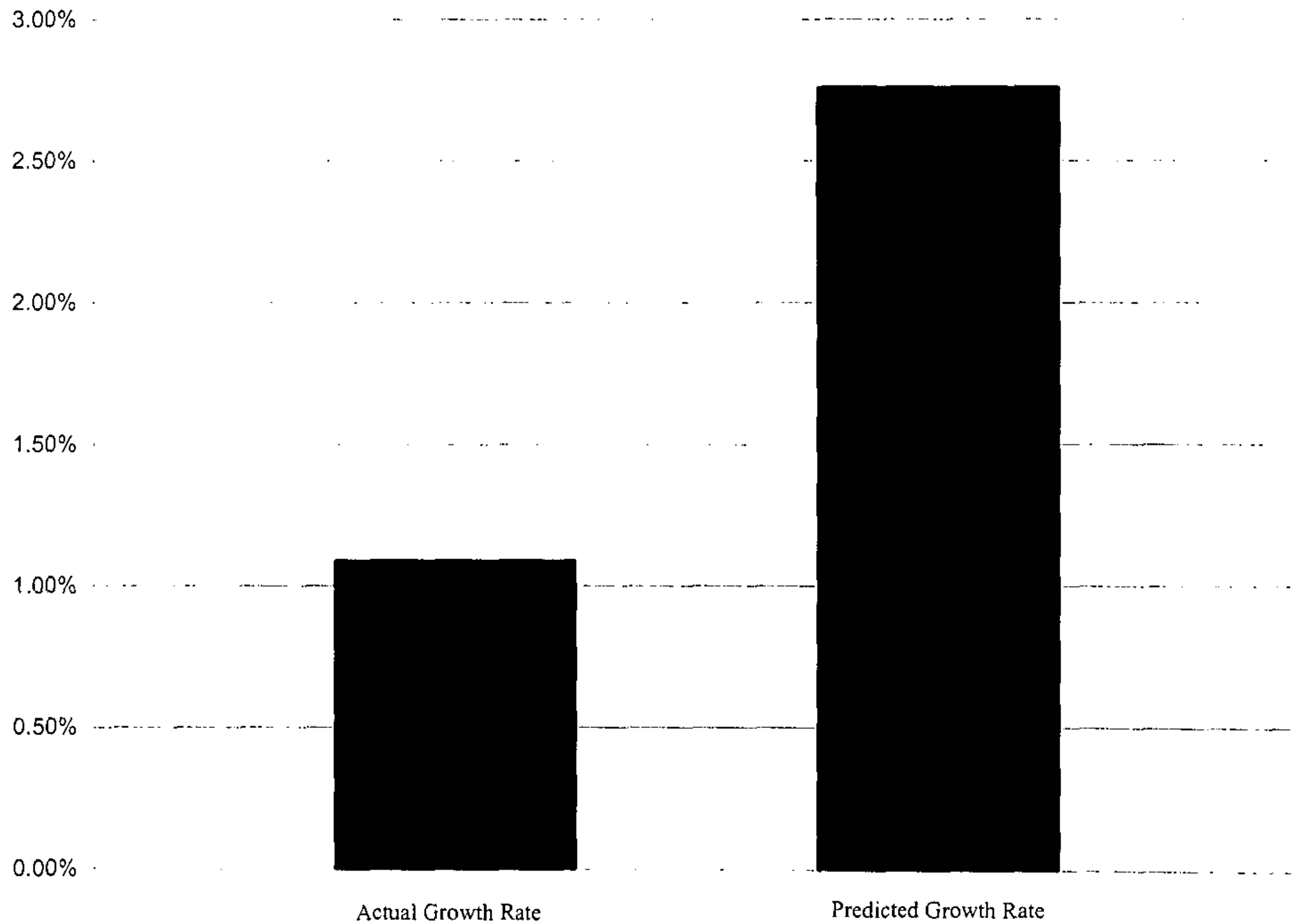


Table 5

ACTUAL COST, PREDICTED COST, AND COST SAVINGS: AMEREN UE 1995-2007

	Growth Rate in Cost: Actual [1]	Growth Rate in Cost: Predicted [1,2]	Growth Rate in Cost: Difference	Actual Cost [3] [A]	Predicted Cost [3] [B]	Annual Cost Savings [B] - [A]	Cumulative Cost Savings	GDPPI [4] [C]	Annual Cost Savings in 2001 Dollars ([B] - [A]) / [C]	Cumulative Savings in 2001 Dollars
1995				$ 1,821,185,162	$ 1,821,185,162					
1996	3.30%	4.98%	-1.68%	$ 1,882,326,971	$ 1,914,217,192	$ 31,890,221	$ 31,890,221	0.914	$ 34,881,524	$ 34,881,524
1997	5.97%	7.65%	-1.68%	$ 1,998,119,770	$ 2,066,397,232	$ 68,277,462	$ 100,167,683	0.932	$ 73,253,446	$ 108,134,970
1998	2.62%	4.30%	-1.68%	$ 2,051,230,278	$ 2,157,261,835	$ 106,031,557	$ 206,199,241	0.944	$ 112,370,233	$ 220,505,203
1999	-0.99%	0.69%	-1.68%	$ 2,030,955,449	$ 2,172,125,860	$ 141,170,411	$ 347,369,651	0.957	$ 147,536,972	$ 368,042,175
2000	2.55%	4.23%	-1.68%	$ 2,083,403,822	$ 2,265,970,194	$ 182,566,372	$ 529,936,024	0.979	$ 186,557,453	$ 554,599,628
2001	3.93%	5.61%	-1.68%	$ 2,166,812,902	$ 2,396,615,130	$ 229,802,228	$ 759,738,251	1.000	$ 229,802,228	$ 784,401,856
2002	2.90%	4.58%	-1.68%	$ 2,230,484,953	$ 2,508,836,324	$ 278,351,371	$ 1,038,089,622	1.020	$ 272,893,501	$ 1,057,295,356
2003	2.90%	4.58%	-1.68%	$ 2,296,028,015	$ 2,626,312,260	$ 330,284,246	$ 1,368,373,868	1.040	$ 317,458,906	$ 1,374,754,262
2004	2.90%	4.58%	-1.68%	$ 2,363,497,067	$ 2,749,288,993	$ 385,791,926	$ 1,754,165,794	1.061	$ 363,540,348	$ 1,738,294,611
2005	2.90%	4.58%	-1.68%	$ 2,432,948,705	$ 2,878,024,095	$ 445,075,390	$ 2,199,241,184	1.082	$ 411,180,863	$ 2,149,475,474
2006	2.90%	4.58%	-1.68%	$ 2,504,441,188	$ 3,012,787,202	$ 508,346,014	$ 2,707,587,197	1.104	$ 460,424,647	$ 2,609,900,121
2007	2.90%	4.58%	-1.68%	$ 2,578,034,486	$ 3,153,860,573	$ 575,826,088	$ 3,283,413,285	1.126	$ 511,317,087	$ 3,121,217,208
Total Savings							**$ 3,283,413,285**			**$ 3,121,217,208**
1995-2001							$ 759,738,251			$ 784,401,856
2002-2007							$ 2,523,675,034			$ 2,336,815,352

[1] Cost growth for 2002-07 is assumed to be the average annual growth in cost for 1995-2001.

[2] The growth in predicted cost is calculated as the sum of the actual cost growth for UE and the estimated average difference between predicted and actual cost using the econometric cost model.

[3] UE's Missouri electric revenue for 1995 is taken as the base for the actual and predicted cost escalations.

[4] Future growth in the gross domestic product price index (GDPPI) is assumed to be 2% per annum.

APPENDIX:

FURTHER DETAILS OF THE RESEARCH

This section provides additional and more technical details of our benchmarking work. We first consider our method for computing the cost of plant ownership. There follow some additional details of our econometric work.

A.1 Cost of Plant Ownership

A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[8] In the application of the general methodology used in this study, capital cost in a given year t, CK_t, is the product of a capital service price index, WKS_t and a capital quantity index, XK_{t-1}.

$$CK_t = WKS_t \cdot XK_{t-1}. \qquad [8]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market. The price and quantity indexes require a consistent mathematical characterization of the process of plant deterioration.

In constructing the indexes we took 1967 as the benchmark or starting year. The values for these indexes in the benchmark year were based on the net value of plant in that year as reported on the FERC Form 1. We estimated the benchmark year (inflation adjusted) value of net plant in that year by dividing the aggregate appropriate base year value by a "triangularized" weighted average of the values of an index of utility asset prices for a period ending in the benchmark year equal to the lifetime of plant. A triangularized weighting gives greater weight to more recent values of this index. This treatment is consistent with the notion

[8] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

that more recent plant additions have a disproportionate impact on the book value of plant.[9] The value of the asset-price index, WKA_t, is the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[10]

The following formula was used to compute subsequent values of the capital quantity index:

$$XK_t = (1 - d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [9]$$

Here the parameter, d, is the economic depreciation rate, VI_t is the value of gross additions to utility plant and WKA_t is the index of utility plant asset prices.

The economic depreciation rate, d, is calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was obtained from the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce. The weights were based on net stock value data drawn from the same source.

The formula for the capital service price index, WKS_t, is:

$$WKS_t = \left(CK_t^{taxes} / XK_{t-1}\right) + r_t \cdot WKA_{t-1} + d \cdot WKA_t - \left(WKA_t - WKA_{t-1}\right) \qquad [10]$$

The four terms in this formula correspond to the four components of the cost of plant ownership. These are: taxes, the opportunity cost of capital, depreciation, and capital gains.[11] Here, CK_t^{taxes} is total tax payments attributed to the IOU. The term, r_t, is the user cost of capital for the U.S. economy.[12] PEG calculates this using data in the National Income and

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[9] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

[10] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[11] The opportunity cost of capital is sometimes called the cost of funds.

[12] The U.S. economy user cost of capital is not directly observable, but it can be measured by applying two economic relationships. The first pertains to the National Income and Products Accounts (NIPA) definitions of Gross Domestic Product (GDP) and the cost of inputs used by the U.S. economy. In the NIPA, the total cost of the U.S. economy inputs is equal to GDP. At the economy-wide level there are two inputs: labor and capital. Therefore the total cost of capital is equal to GDP less Labor Compensation (CL), or:

$$CK = GDP - CL \qquad (1)$$

Product Accounts (NIPA). The accounts are published by the Department of Commerce in its *Survey of Current Business* series. Capital gains are smoothed using a three-year moving average.

A.2 Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[13] This very flexible representation of a cost function is frequently used in econometric cost research and is by some accounts the most reliable of several available alternatives.[14] The general form of the translog cost function is:

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where CK represents the total cost of capital. The second relationship is between the total cost of capital and the components of the capital price equation. The total cost of capital is equal to the product of the quantity of capital input and the price of capital input, or:

$$CK = P_k \cdot K \qquad (2)$$

where P_k represents the price and K the quantity of capital input. The price of capital can be decomposed into the price index for new plant and equipment (J), the opportunity cost of capital (r), the rate of depreciation (d), the inflation rate for new plant and equipment (I), and the rate of taxation on capital (t):

$$P_k = J \cdot (r + d - I + t) \qquad (3)$$

Combining (2) and (3) one obtains the relationship:

$$\begin{aligned} CK &= J \cdot (r + d - I + t) \cdot K \\ &= r \cdot J \cdot K + d \cdot J \cdot K - I \cdot J \cdot K + t \cdot J \cdot K \qquad (4) \\ &= r \cdot VK + D - I \cdot VK + T \end{aligned}$$

where D represents the total cost of depreciation, T total indirect business taxes and corporate profits taxes, and VK the current cost of plant and equipment net stock. Combining (1) and (4), one can derive the following equation for the opportunity cost of capital:

$$r = {(GDP - CL - D - T + I \cdot VK)} \big/ {(VK)}. \qquad (5)$$

GDP, labor compensation, depreciation, and taxes are reported annually in the NIPA. The current cost of plant and equipment net stock and the inflation rate for plant and equipment are not reported in the NIPA, but are reported in *Fixed Reproducible Tangible Wealth in the United States*.

[13] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[14] For more on the advantages of the translog form see Guilkey (1983), et. al.

$$\ln C = \alpha_0 + \sum_h \alpha_h^Y \ln Y_h + \sum_j \alpha_j^W \ln W_j$$
$$+\frac{1}{2}\left(\sum_h \sum_m \gamma_{h,m}^{YY} \ln Y_h \ln Y_m + \sum_j \sum_n \gamma_{j,n}^{WW} \ln W_j \ln W_n\right) \qquad [11]$$
$$+\sum_h \sum_j \gamma_{h,j}^{YW} \ln Y_h \ln W_j$$

where Y_h denotes one of M variables that quantify output and the W_j denotes one of N input prices.[15]

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the value of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at smaller values of the variable than at larger variables. This type of relationship between cost and quantity is often found in cost research.

Business conditions other than input prices and output quantities can contribute to differences in the costs of utilities. As noted in Section 3.2.3 above, these additional variables include the load factor and the percentage of electric plant in the gross value of combined gas and electric distribution plant. We have elected not to translog most of these additional business conditions so as to contain the complexity of estimation and the number of parameters requiring estimation.

Cost theory requires a well-behaved cost function to be homogeneous in input prices. This would imply the following three sets of restrictions for the model in Equation [11]:

$$\sum_h^N \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad [12]$$

$$\sum_h^N \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,..., N \qquad [13]$$

$$\sum_h^N \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln Y_j} = 0 \qquad \forall j = 1,..., M. \qquad [14]$$

[15] Additional business conditions that might be added to the formula are excluded to simplify the discussion.

Imposing the above $(1+N+M)$ restrictions implied by Equations [12-14] allow us to reduce the number of parameters that need be estimated by the same amount.

Estimation of the parameters in Equation [11] is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma.[16] The general form of a cost share equation for a representative input price category, j, can be written as:

$$S_j = \alpha_j + \sum_h \gamma_{h,j}^{YW} \ln Y_h + \sum_\ell \gamma_{j,\ell}^{WW} \ln W_\ell . \qquad [15]$$

We note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

The addition of these cost share equations means that we require procedures to estimate a system of equations. We could estimate this system using the Ordinary Least Square (OLS) procedure but instead employ a more efficient estimation procedure first proposed by Zellner (1962).[17] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve an even better estimator, PEG iterates this procedure to convergence.[18] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are

[16] For a discussion see Varian (1984).
[17] See Zellner, A. (1962).
[18] That is, we iterate the procedure until the determinant of the difference between any two consecutive estimated disturbance matrices are approximately zero.

equivalent to Maximum Likelihood Estimation (MLE).[19] Our estimates would thus possess all the highly desirable asymptotic properties of MLEs, including consistency and efficiency.

Before proceeding with estimation, some additional complications needed to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[20] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

Another complication is the type of data being used. In the research on UE's recent performance level over the 1998-2001 period, we averaged the available values of cost function variables for each company over the years of the sample period prior to estimation. For example, the cost variable used in the regression work was the average value for each company over the three-year period. The resultant estimator is therefore based on the "between" utility variation and is commonly referred to as a "between" estimator. This approach has advantages in the isolation of the efficiency factor that is the focus of this research.

Between estimation is not appropriate for cost *trend* research because it does not accommodate the inclusion of an explicit trend variable to capture any shift in the cost of sampled utilities over time that is not due to changes in business conditions. For the econometric cost growth research, we therefore did not average the values of the cost function variables. We also used data for the 1995-2000 sample period. This is the full portion of the 1995-2001 period addressed by the cost trend model for which sample data are currently available.

These measures made possible a substantial increase in the size of the data set. This increased the chances of finding other business condition variables to be statistically significant. In fact, five additional business condition variables were found to be significant cost drivers in the model used for cost growth appraisal, as we note above.

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[19] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

One other aspect of our econometric research merits note. Both model specifications were determined using the data for all sampled companies, including UE. However, to compute the standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation.[21] The standard error based on this "out-of-sample" prediction was then used to construct interval predictions for the true level of cost.

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[20] This equation can be estimated indirectly from the estimates of the parameters remaining in the model.

[21] This implies that the estimates used in constructing the predicting equation will vary slightly from those reported in the study.

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