# The Performance of AmerenUE Under the EARPS

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# TABLE OF CONTENTS

# 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 | Company |
|---|---|
| AmerenUE | Maine Public Service Co |
| AmerenCIPS | Minnesota Power Inc |
| Appalachian Power Co (VA) | Mississippi Power Co |
| Arizona Public Service Co | Montana-Dakota Utilities Co |
| Atlantic City Electric Co | Nevada Power Co |
| Baltimore Gas & Electric Co | Northern Indiana Public Service Co |
| Carolina Power & Light Co | Northern States Power Co |
| Central Hudson Gas & Electric Corp | Northwestern Public Service Co (SD) |
| Central Illinois Light Co | Ohio Edison Co |
| Central Power & Light Co (TX) | Ohio Power Co |
| Cleco Corp | Oklahoma Gas and Electric Co |
| Cleveland Electric Illuminating Co (OH) | Orange and Rockland Utilities Inc |
| Columbus Southern Power Co (OH) | Otter Tail Power Co |
| Consumers Energy Co (MI) | PacifiCorp |
| Dayton Power & Light Co (OH) | Pennsylvania Electric Co |
| Delmarva Power & Light Co | Pennsylvania Power Co |
| Detroit Edison Co | Portland General Electric Co |
| Duke Energy Corp | Potomac Electric Power Co |
| Duquesne Light Co | PP&L Inc |
| El Paso Electric Co | Public Service Co of Colorado |
| Empire District Electric Co (MO) | Public Service Co of New Mexico |
| Entergy Arkansas Inc | Public Service Co of Oklahoma |
| Entergy Gulf States Inc | Saint Joseph Light & Power Co |
| Entergy Louisiana Inc | San Diego Gas & Electric Co |
| Entergy Mississippi Inc | Savannah Electric and Power Co |
| Florida Power & Light Co | Sierra Pacific Power Co |
| Florida Power Corp | South Carolina Electric & Gas Co |
| Georgia Power Co | Southern Indiana Gas and Electric Co |
| Gulf Power Co | Southwestern Electric Power Co (LA) |
| Illinois Power Co | Southwestern Public Service Co |
| Indiana Michigan Power Co | Tampa Electric Co |
| Indianapolis Power & Light Co | Texas Utilities Electric Co |
| Interstate Power Co | Toledo Edison Co |
| Kansas City Power & Light Co (MO) | Tucson Electric Power Co |
| Kansas Gas and Electric Co | United Illuminating Co |
| Kentucky Power Co | West Texas Utilities Co |
| Kentucky Utilities Co | Wisconsin Electric Power Co |
| Louisville Gas and Electric Co (KY) | Wisconsin Power and Light Co |
| Madison Gas and Electric Co (WI) | 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 $\alpha_{0,t}$, $\alpha_1$, and $\alpha_2$ 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 $\alpha_1$ and $\alpha_2$ determine the effect of the two measured business conditions on cost. If the value of $\alpha_2$ 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 $\alpha_1$ 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]

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

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

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

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

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

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 $\alpha_2$, 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

[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.

[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 | EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T-STATISTIC |
|---|---|---|---|---|---|
| L | 0.093 | 62.349 | VX | 0.632 | 22.741 |
| LL | 0.055 | 7.733 | VXVX | 0.368 | 3.592 |
| LK | -0.044 | -5.862 | VXLF | 0.380 | 2.178 |
| LE | -0.043 | -7.533 | | | |
| LN | 0.032 | 6.394 | LF | -0.309 | -3.938 |
| LVX | -0.033 | -7.276 | LFLF | -1.510 | -2.202 |
| LLF | 0.047 | 3.801 | | | |
| | | | %E | 0.153 | 2.876 |
| K | 0.487 | 131.653 | | | |
| KK | 0.160 | 10.460 | M | 0.062 | 3.799 |
| KE | -0.134 | -10.855 | | | |
| KN | 0.017 | 1.445 | %O | -0.115 | -2.666 |
| KVX | 0.006 | 0.532 | | | |
| KLF | -0.112 | -3.673 | %H | 0.657 | 2.269 |
| | | | | | |
| E | 0.293 | 57.760 | T | -0.017 | -4.909 |
| EE | 0.165 | 9.371 | | | |
| EN | -0.056 | -3.409 | | | |
| EVX | 0.032 | 2.135 | | | |
| ELF | 0.030 | 0.710 | | | |
| | | | Constant | 21.157 | 2309.301 |
| N | 0.311 | 9.904 | | | |
| NN | 0.276 | 2.664 | | | |
| NVX | -0.321 | -3.155 | System Rbar-Squared | 0.994 | |
| NLF | -0.606 | -3.075 | | | |
| | | | 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 | EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T-STATISTIC |
|---|---|---|---|---|---|
| L | 0.082 | 26.217 | VX | 0.769 | 13.218 |
| LL | 0.074 | 4.594 | VXVX | 0.119 | 0.484 |
| LK | -0.063 | -3.245 | VXLF | 0.252 | 0.614 |
| LE | -0.058 | -4.564 | | | |
| LN | 0.026 | 2.379 | LF | -0.502 | -3.035 |
| LVX | -0.031 | -3.065 | LFLF | 0.169 | 0.127 |
| 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 | Constant | 21.210 | 1032.553 |
| 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 | System Rbar-Squared | 0.994 | |
| | | | | | |
| N | 0.237 | 4.036 | Sample Period: | 1998-2000 | |
| NN | -0.131 | -0.491 | | | |
| NVX | 0.005 | 0.019 | Number of Obsevations | 78 | |
| NLF | -0.578 | -1.219 | | | |

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**

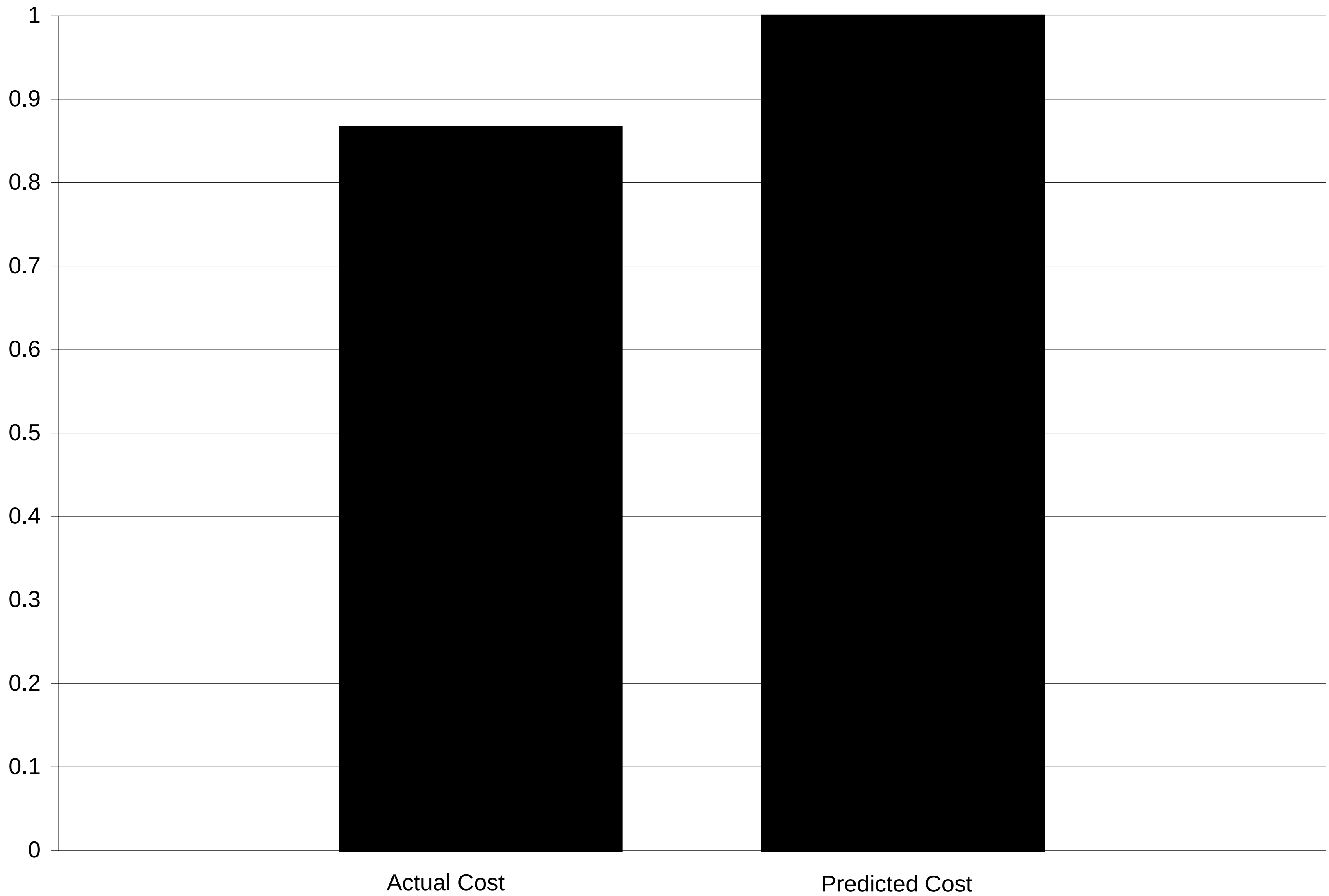

Figure 2

## Actual and Predicted Growth Rates of Cost For AmerenUE

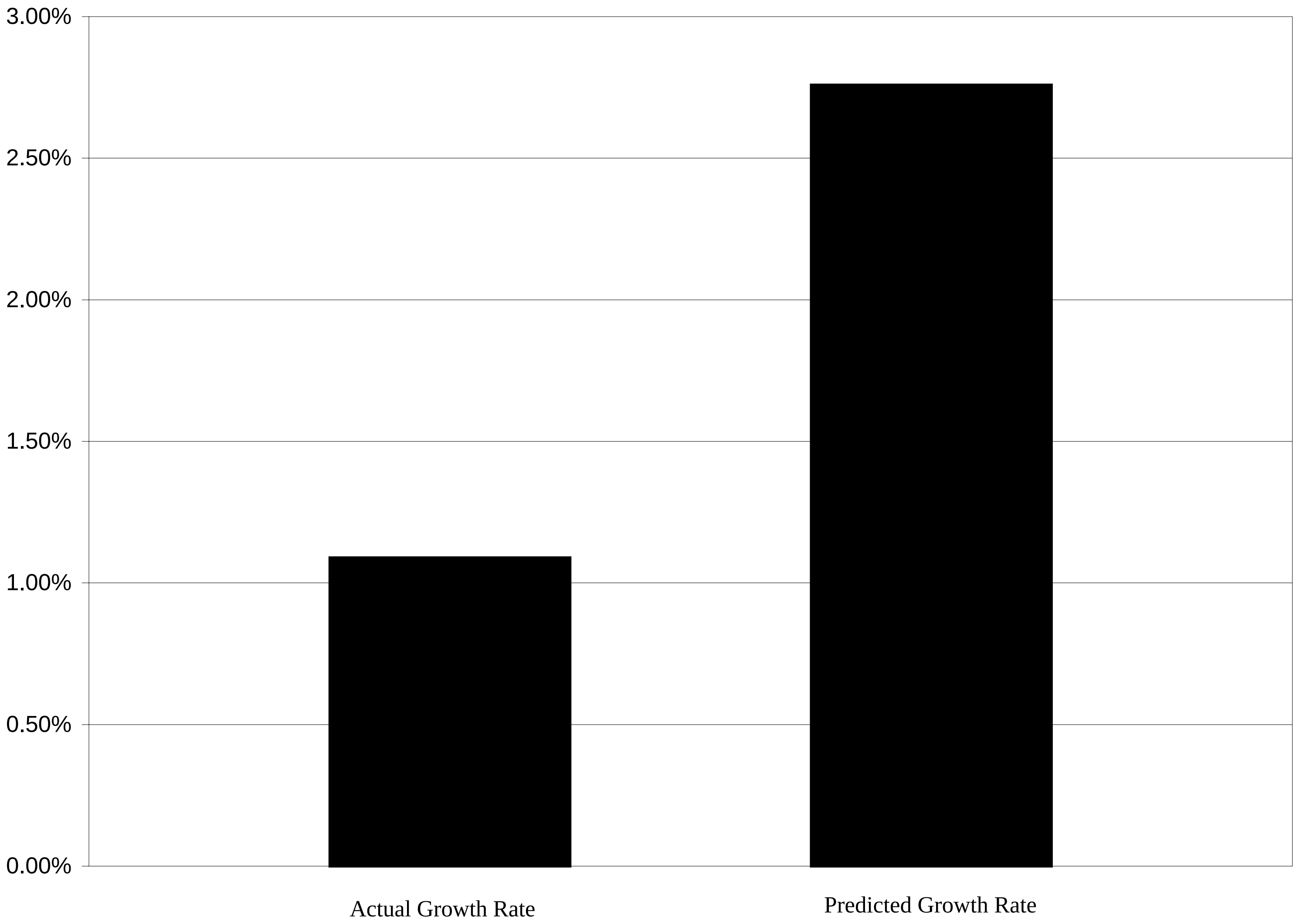

Table 5

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

| | Growth Rate in Cost | | | Actual Cost [3] | Predicted Cost [3] | Annual Cost Savings | Cumulative Cost Savings | GDPPI [4] | Annual Cost Savings in 2001 Dollars | Cumulative Savings in 2001 Dollars |
|---|---|---|---|---|---|---|---|---|---|---|
| | Actual [1] | Predicted [1,2] | Difference | [A] | [B] | [B] - [A] | | [C] | ( [B] - [A] ) / [C] | |
| 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:

---

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 (l), and the rate of taxation on capital (t):

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

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

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

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:

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

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.

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

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]:

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

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

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

[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

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[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.

[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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