

RECENT COST PERFORMANCE OF OKLAHOMA GAS & ELECTRIC

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Executive Summary

A central issue in utility regulation is the interpretation of operating data to ascertain whether the utility is operating efficiently. Regulators naturally want to know whether utility management is doing a good job. Statistical benchmarking using publicly available data on utility operations is a useful tool for appraising cost performance. A recent study by the National Regulatory Research Institute encouraged greater use of benchmarking in regulation.¹

This paper reports on a statistical benchmarking study of the recent cost performance of Oklahoma Gas and Electric (“OG&E” or “the Company”). The focus of the study was generation maintenance expenses and a broader class of non-fuel O&M expenses that are amenable to accurate benchmarking. This report provides details of our studies.

Benchmarking Methods

OG&E, like other utilities, faces a unique set of local business conditions such as service infrastructure, demand characteristics, and geography. Many of these factors have a demonstrable impact on cost that is largely beyond the Company’s control. To better estimate the cost performance of OG&E we used two well established statistical methods --- econometrics and unit cost indexing --- to develop benchmarks that account for external factors.

Guided by cost theory, we developed econometric models of the impact that various quantifiable business conditions have on the non-fuel O&M expenses and generation maintenance expenses of vertically integrated electric utilities (“VIEUs”) like OG&E. Each business condition variable in the two models has a parameter that measures its impact on cost. These parameters were estimated statistically using historical data on utility operations drawn from respected public sources such as the Federal Energy Regulatory Commission (“FERC”). The samples of utility operating data were large and varied enough to permit development of credible cost models. Both models were found to have high explanatory

¹Evgenia Shumilkina, “Utility Performance: How Can State Commissions Evaluate It Using Indexing, Econometrics, and Data Envelopment Analysis?”, National Regulatory Research Institute 10-05, March 2010.



power. All estimates of model parameters were plausible and all but two had high statistical significance.

We used each model to predict OG&E's corresponding cost during the 2008-2010 period. The predicted cost values were the benchmarks and reflect OG&E's local business conditions. We then compared OG&E's actual cost to the econometric benchmarks. Good performance is reflected in utilities that have relatively low actual costs as compared to their respective benchmarks.

Our second method for ascertaining the performance of OG&E was to compare the Company's unit cost (cost per unit of output) to the average unit cost across a peer group using unit cost indexes. There were different peer groups for generation maintenance and non-fuel O&M expenses. Both unit cost indexes compared the operating scale of OG&E to that of the peer group using multiple output variables. The output weights for the indexes and the selection of peer groups was guided by our econometric work.

Research Results

Non-Fuel O&M Expenses

The non-fuel O&M expenses of OG&E were found to be about 20% below the benchmark generated by the econometric O&M cost model on average from 2008 to 2010. This performance, which was sixth best in the sample, was in the top quartile. In other words, more than three quarters of the sampled utilities had costs that compared less favorably to their econometric benchmarks. In 2010, non-fuel O&M expenses were about 12% below the benchmark produced by the econometric model. This was also a top quartile performance. OG&E's success in sustaining a high performance ranking in recent years has been remarkable.

OG&E's unit non-fuel O&M cost was about 23% below the norm for the sampled utilities on average from 2008 to 2010. The Company's unit cost was about 19% below the norm on average in 2010. The unit cost results corroborate the econometric results and support a finding that OG&E continues to be a superior cost manager.



Generation Maintenance Expenses

From 2008 to 2010, the generation maintenance expenses of OG&E were found to be on average about 25% below the benchmark generated by the econometric maintenance cost model. This performance was in the top quartile. In 2010, generation maintenance expenses were about 4% below the benchmark produced by the econometric model. This was a second quartile performance. OG&E's unit generation maintenance cost was about 22% below the norm for the peer group on average from 2008 to 2010. The Company's unit cost was 10% below the peer group norm on average in 2010. Using both benchmarking methods, we therefore find that while OG&E's generation maintenance expenses in 2010 were higher than in some recent years, they were still quite reasonable.



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1. Introduction

Statistical benchmarking has in recent years become a widely used tool in the assessment of utility performance. Managers use benchmarking to gauge how well their companies are operating. Benchmarking also plays a growing role in regulation. Benchmarking studies can, for instance, be used to assess the reasonableness of utility proposals to establish new rates or multi-year rate plans.

The benchmarking of utilities is facilitated by the extensive operating data which they report to government agencies. However, accurate performance appraisals also require statistical methods and an understanding of utility operations and data. There are important differences between utilities in the scale of their operations, the prices they pay for inputs, and in other business conditions that influence their cost.

Personnel of Pacific Economics Group (“PEG”) Research LLC have been active for more than twenty years in the field of utility performance research. We pioneered the use of rigorous benchmarking methods in North American regulation. Senior author Mark Newton Lowry has testified on utility performance in numerous proceedings.

OG&E has retained PEG Research to prepare a study of its recent cost efficiency. The focus of the study is generation maintenance expenses and a broader class of non-fuel O&M expenses that is suitable for benchmarking. This report provides details of these studies. Section 2 of the report provides an introduction to benchmarking methods. Section 3 discusses our research for OG&E. More technical details of the research are presented in the Appendix.



2. Benchmarking Methodology

This section provides a non-technical discussion of some important benchmarking concepts and details the two benchmarking methods used in the study. More technical aspects of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word “benchmark” was originally a term of art used by surveyors. The *Oxford English Dictionary* defines a benchmark as:

A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used to indicate something that can be used as a point of comparison in appraisals of performance.

Statistics are often used in such performance comparisons. For example, statistical benchmarking plays a major (if informal) role in player selection to the Pro Football Hall of Fame. Running backs, for example, are evaluated using statistics on their touchdowns, rushing yardage, and fumbles. The values achieved by Hall of Fame members like Barry Sanders are expected to be far better than those for an average player. Values that are markedly superior to the norm reflect a Hall of Fame performance standard.

Statistical performance benchmarking commonly involves one or more performance metrics, which are sometimes called key performance indicators (“KPIs”). The values of the KPIs achieved by an entity under scrutiny are compared to benchmark values that reflect performance standards. Statistical methods are used both to calculate benchmarks and to draw inferences about performance from benchmark comparisons. Statistical performance benchmarking of regulated utilities requires establishing KPIs and benchmarks that are relevant to utility performance. For example, given information on a utility’s cost and a certain cost benchmark we might estimate cost performance by taking the ratio of the two values:

$$\text{Cost Performance} = \text{Cost}^{\text{Actual}} / \text{Cost}^{\text{Benchmark}}.$$



In this case, a smaller cost performance number indicates better efficiency. Cost performance values greater than 1 indicate that the utility's actual costs exceed the benchmark value, and values below 1 indicate that a utility has achieved costs below the benchmark. Cost performance comparisons for multiple utilities can be used to rank the relative cost efficiency of those utilities.

2.2 Importance of Cost Drivers

When trying to determine the relative performance of two sprinters, comparing their times in the 100-meter dash when one runner is running uphill and into a stiff wind while the other runs on a level track with a strong tailwind doesn't tell us much about what their relative performances would likely be in a head-to-head race. Similarly, in reviewing cost metrics and other types of business KPIs, it is widely recognized that differences in the values of the indicators that companies achieve depend significantly on the unique business conditions that each faces. In cost research, these unique conditions are sometimes called cost "drivers." Cost benchmarks can shed light on the performance of a utility's management if they reflect the typical impact of the cost drivers that the utility faces.

Economic theory is useful for identifying cost drivers so that their influence is considered in benchmarking studies. Under certain reasonable assumptions, cost "functions" exist that relate the minimum cost of a utility to the unique business conditions in its service territory. When the focus of benchmarking is a subset of total cost such as O&M expenses, cost theory reveals that the relevant business conditions include the prices of O&M inputs, the operating scale of the company, and the amounts of other, non-O&M inputs (*e.g.* capital) that the company uses.

The theoretical existence of "other input" variables in an O&M cost function means that a good appraisal of the efficiency of a utility in using O&M inputs should consider in some fashion the amounts of other inputs that it uses. This result is important for several reasons. Different production technologies may have different O&M requirements. Nuclear generation facilities, for instance, seem to require more O&M than a bank of combustion turbines with similar capacity. Opportunities often exist to substitute inputs in production. For example, a utility that generates its power from a new plant may spend less on maintenance than a utility that is



struggling to keep an older plant in service. The owner of the new plant will bear higher capital depreciation expenses. Capital inputs have thus been substituted for O&M inputs.

Another reason that other inputs matter in an O&M cost study is that utilities use different methods to classify costs. Utilities may, for instance, differ in the way that they categorize certain expenditures between administrative and direct operating expenses, or between labor and non-labor inputs. As a general rule, therefore, benchmarking will tend to be simpler and more accurate to the extent that the scope of costs under consideration is comprehensive. For example, it will be easier to accurately benchmark *total* base rate O&M expenses than it will be to accurately benchmark *labor* expenses.

Regardless of the particular category of cost that a benchmarking study focuses on, economic theory allows for the existence of *multiple* output variables in the cost function. In other words, it is reasonable and often desirable to use multiple measures of operating scale. This is especially true for a vertically integrated electric utility like OG&E, which is in the business of providing diverse services that in other parts of the country are provided by separate and independent companies. The cost of a VIEU depends, for instance, on the number of customers it serves (as it provides “distribution service”) as well as on its generation volume (as it provides “generation service”). It is also noteworthy that theory allows for numerous business conditions other than input prices, output quantities, and other inputs to affect the cost of service.

2.3 Benchmarking Methods

In this section we discuss the two benchmarking methods that we used in our study for OG&E: econometric modeling and unit cost indexing. We begin with the econometric method to establish a better context for the discussion of the indexing method.

2.3.1 Econometric Modeling

In Section 2.2, we noted that comparing the results of a 100-meter sprinter racing uphill into a stiff wind to a runner racing on a level course with a strong tailwind doesn’t tell us much about the relative performance of the athletes and what their relative performances would be in a head-to-head race. We could, however, use statistics to infer information about their relative performances. For example, we could develop a theoretical model that related time in the 100-meter dash to track conditions like wind speed and direction and the incline of the track. We



could then use a sample of 100-meter times turned in by runners under varying track conditions to estimate the effects of wind speed, incline and other conditions statistically. These estimated effects could then be used to compare the performances of the two sprinters given the track conditions that they faced. Computer models used to rank college football teams use statistics to estimate the impact on a team's winning percentage of the strength of its schedule and the percentage of its games played at home. Both exercises are analogous to the econometric modeling method used in this study: since the cost drivers faced by different utilities are unique, we statistically estimate the effects of these conditions, and control for them in our measurement of performance.

Basic Assumptions

The impact of external business conditions on the costs of utilities can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the impact of business conditions on economic variables using historical data.² First, the general form of the utility's cost function is specified. Econometric methods are then used to statistically quantify the impact of each cost driver in the model using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The result is a model that adds up the impacts of each individual cost driver on the utility's cost.

For example, if cost were simply a function of the number of customers and the average utility wage rate (not generally true), we might develop the following cost model:

$$Cost = a_0 + a_1 * Customers + a_2 * Wage.$$

In this equation the terms a_1 and a_2 are the cost model "parameters". They measure the respective impact of customers and wages on utility costs. The values of the parameters are estimated econometrically. The sample used in parameter estimation can be a "time series" consisting of data over several years for a single company, a "cross section" consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

The results of econometric research are useful in identifying which business conditions drive utility cost. For example, econometric methods allow one to test the hypothesis that the

² The act of estimating model parameters is sometimes called regression.



parameter for a candidate cost driver equals zero. A cost driver can be deemed statistically significant if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to “predict” a company’s historical cost given local values for the cost-driver variables. These predictions are econometric benchmarks. Cost performance is measured by comparing a company’s cost in year t to the cost projected for that year and company by the econometric model.

Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Southwest Power. We might then predict the cost of Southwest in period t using the following model.

$$\hat{C}_{Southwest,t} = \hat{a}_0 + \hat{a}_1 * N_{Southwest,t} + \hat{a}_2 * W_{Southwest,t}.$$

Here $\hat{C}_{Southwest,t}$ denotes the predicted cost of the Company, $N_{Southwest,t}$ is the number of customers it served, and $W_{Southwest,t}$ measures its wage rate. The \hat{a}_0 , \hat{a}_1 , and \hat{a}_2 terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance_t = \left(\frac{C_{Southwest,t}}{\hat{C}_{Southwest,t}} \right).$$

Accuracy of Benchmarking Results

Statistical theory provides useful guidance regarding the accuracy of an econometric benchmark as a predictor of the benchmark that truly reflects the impact of local cost drivers. One important result is that a model can yield *biased* predictions of the true benchmark if relevant cost drivers are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all cost drivers which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.



Even when an econometric model is unbiased it can be imprecise, yielding benchmarks that are too high for some companies and too low for others. Statistical theory suggests that the benchmark will be more precise to the extent that

- the model is successful in explaining the variation in cost in the historical data used in model development;
- the size of the sample used in model estimation is large;
- the number of cost driver variables included in the model is small relative to the sample size;
- the business conditions of sampled utilities are varied; and
- the business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will be more accurate to the extent that it is based on a large sample of good operating data from companies with diverse operating conditions. There is no problem using in model estimation data from utilities with business conditions quite different from those of the subject utility so long as sample mean business conditions are fairly similar to the utility's on balance. When the sample is small, it will be difficult to identify all of the relevant cost drivers or to estimate their impacts accurately. It follows that it will generally be preferable to use panel data, encompassing information from multiple utilities over time, when these are available instead of a single cross section of data from several firms measured at a single point in time. Fortunately, large panels of good data on the operations of electric utilities are readily available in the United States.

2.3.2 Benchmarking Indexes

In their internal reviews of operating performance, utilities tend to employ the index approach to benchmarking in lieu of the econometric approach just described. Benchmarking indexes are also used sometimes in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost indexes.



Index Basics

An index is defined in one dictionary as “a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)”.³ In utility-performance benchmarking, indexing involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The companies that comprise the sample are sometimes called a peer group.

Indexes can be designed to summarize the results of multiple comparisons. Such summaries commonly involve the calculation of *weighted averages* of the comparisons. Consumer price indexes are familiar examples. These summarize the inflation (year-to-year comparisons) in the prices of a “market basket” consisting of hundreds of goods and services. The weight for the inflation in the price of each product is its share of the value of all of the products in the basket. Thus if consumers typically spend \$40 a week on beef and \$5 on butter, beef might have a 2% weight in the index whereas butter might have only a 0.25% weight. A 5% increase in the price of steak would then have a much bigger impact on the inflation in the summary index than a 5% increase in the price of butter.

To better appreciate the advantages of multi-category indexes in benchmarking, recall from our discussion in Section 2.2 that the operating scale of a VIEU is often best measured using multiple output variables. These variables can have markedly different impacts even if all are worth considering. We can construct an output (quantity) index that takes a weighted average of output comparisons made using multiple variables.

In a cost-benchmarking application, it makes sense for the weights of an output index to reflect the relative importance of the individual output variables as cost drivers. The cost impact of an output variable is conventionally measured by its cost “elasticity”. The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate the required elasticities using econometric estimates of cost model parameters. We can then use as the weight

³ *Webster’s Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co., 1966).



for each variable in an output index the share of its corresponding cost elasticity estimate in the sum of the estimated cost elasticities of the model's output variables.⁴

Unit Cost Indexes

A unit cost index is the ratio of a cost index to an output index. Each index compares the value for the subject utility to the average for a peer group. A unit cost index for Southwest Power, for instance, would have the general form

$$Unit\ Cost_t^{Southwest} = \frac{Cost_t^{Southwest} / Cost_t^{Peers}}{Output_t^{Southwest} / Output_t^{Peers}}.$$

In comparing the unit cost of a utility to the average for a peer group, we effectively introduce an automatic control for differences between the companies in operating scale, which as we have seen is an important cost driver. This permits us to include companies with more varied operating scales in the peer group. The output index can be multidimensional if it is desirable to measure operating scale using multiple output variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility. Thus, the choice of the peer group is an important step in a unit cost benchmarking exercise. Economic research on the drivers of utility cost is useful in peer group selection.

2.3.3 Averaging

Utilities manage their costs to reflect expected business conditions over a series of years and not the conditions specific to a single year. Cost in a single year may be sensitive to conditions, such as tornadoes and other severe weather events, which aren't considered in benchmarking because they are difficult to measure. Appraisals of cost efficiency are, therefore,

⁴ The concept of an elasticity-weighted output index is advanced in Denny, Michael, Melvyn A. Fuss and Leonard Waverman, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York, 1981) pages 172-218.



frequently made over a multi-year timeframe. We routinely assess efficiency over the most recent three years for which data have been gathered.



3. Empirical Research for OG&E

3.1 Data

As mentioned earlier, the energy utility industry is unusual in that detailed national operating data have been compiled by reliable sources for decades. Collection of many of these data is a legal mandate. The source of the cost and generation volume data used in this study was the Federal Energy Regulatory Commission (“FERC”) Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC’s Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations. Other data sources accessed in the research included the Bureau of Labor Statistics (“BLS”) of the U.S. Department of Labor, the U.S. Energy Information Administration (“EIA”), Global Insight, and McGraw Hill.

Data were considered for inclusion in the O&M sample from all major U.S. investor-owned electric utilities that filed the Form 1 and had substantial involvement in power generation, transmission, and distribution throughout the sample period. Data were considered for inclusion in the generation maintenance sample from companies that had substantial involvement in fossil-fueled generation throughout the sample period. To be included in the study, the data were also required to be plausible and not unduly burdensome to process. Data from 45 companies were used to develop the econometric O&M benchmarking model. Data from 54 companies were used to develop the generation maintenance benchmarking model. The smaller data set for research on the O&M of VIEUs is due to the fact that several U.S. electric utilities that generate power have in recent years sold or spun off their transmission systems. The sampled companies are listed in Tables 1 and 2.

The sample period for the benchmarking studies was 1995-2010. The resultant O&M data set has 720 observations on each model variable. The generation maintenance data set had 864 observations on each model variable. Both samples are large and varied enough to permit recognition of numerous cost drivers.



Table 1

ELECTRIC UTILITY DATA USED IN O&M COST RESEARCH

Alabama Power	Kentucky Utilities
Appalachian Power	Louisville Gas & Electric
Arizona Public Service	Montana-Dakota Utilities
Avista	MidAmerican Energy
Black Hills Power	Nevada Power
Carolina Power & Light	Northern Indiana Public Service
Cleco Power*	Northern States Power (MN)
Columbus Southern Power	Oklahoma Gas and Electric
Dayton Power & Light	Portland General Electric
Duke Energy Carolinas	Public Service Company of Colorado
Duke Energy Indiana	Public Service Company of New Hampshire
Duke Energy Ohio	Public Service Company of Oklahoma*
Empire District Electric	PacifiCorp
Entergy Arkansas	Puget Sound Energy
Entergy Mississippi*	Sierra Pacific Power
Florida Power & Light	South Carolina Electric & Gas
Florida Power	Southern Indiana Gas & Electric
Georgia Power	Southwestern Electric Power*
Gulf Power	Southwestern Public Service*
Idaho Power	Tampa Electric
Indianapolis Power & Light	Virginia Electric & Power
Kansas City Power & Light	Western Resources
Kentucky Power	

* O&M peer group member

Number of companies in O&M sample: 45

Table 2

ELECTRIC UTILITY DATA USED IN GENERATION MAINTENANCE COST RESEARCH

Alabama Power	Montana-Dakota Utilities
Appalachian Power	MidAmerican Energy
Arizona Public Service	Mississippi Power
Avista	Nevada Power
Black Hills Power	Northern Indiana Public Service
Carolina Power & Light	Northern States Power (MN) #
Cleco Power	Ohio Power
Columbus Southern Power	Oklahoma Gas and Electric
Dayton Power & Light	Portland General Electric
Detroit Edison	Public Service Company of Colorado
Duke Energy Carolinas	Public Service Company of Oklahoma #
Duke Energy Indiana	Public Service Company of New Hampshire
Duke Energy Ohio	Public Service Company of New Mexico
El Paso Electric	PacifiCorp
Entergy Arkansas #	Puget Sound Energy
Florida Power & Light	Sierra Pacific Power
Florida Power	South Carolina Electric & Gas
Georgia Power	Southern Indiana Gas & Electric
Gulf Power	Southwestern Electric Power
Idaho Power	Southwestern Public Service ¹ #
Indianapolis Power & Light	Tampa Electric
Kansas Gas and Electric	Tucson Electric Power
Kansas City Power & Light	Union Electric
Kentucky Power	Virginia Electric & Power
Kentucky Utilities	Western Resources
Louisville Gas & Electric	Wisconsin Electric Power
Madison Gas and Electric	Wisconsin Power and Light
	Wisconsin Public Service

Generation maintenance peer group member

Number of companies in generation maintenance econometric sample: 54

¹Southwestern Public Service is a member of the unit cost peer group but was excluded from the econometric sample

3.2 Benchmarking OG&E's Non-Fuel O&M Expenses

3.2.1 Calculating O&M Expenses

The expenses addressed in the O&M benchmarking work were total electric O&M expenses less reported expenses in the FERC Form 1 categories for fuel, purchased power, customer service and information, employee pensions and benefits, franchise fees, and certain transmission activities.⁵ We routinely exclude expenses for fuel, purchased power, and pensions and benefits from our O&M benchmarking studies on the grounds that they are large, volatile, and --- to a considerable degree --- beyond the control of utility management. Customer service and information expenses were excluded because these vary greatly with the extent of demand-side management programs and it is difficult to measure the scale of these programs. Franchise fees also vary greatly between utilities and are substantially beyond their control.

As for the excluded transmission expenses, the cost of transmission services purchased from other utilities varies widely and is fortunately itemized for easy removal. Some sampled utilities are members of regional transmission organizations (“RTOs”) that undertake certain transmission services (*e.g.* dispatching and planning) for members and may also manage regional bulk power markets. This makes it undesirable to include these expense categories in a benchmarking study. Additionally, RTO member utilities provide RTOs with maintenance and other transmission services. The RTOs invoice member utilities large sums that include costs of the services that the utilities provide. These invoiced sums are sometimes reported by the utilities as O&M expenses. We have accordingly removed from the transmission expenses of all sampled companies the expenses for services that an RTO might provide, as well as the expense categories where RTO charges to the utility might be listed. The categories excluded comprise system control and load dispatching (FERC account 556), transmission load dispatching (FERC account 561), miscellaneous transmission expenses (FERC account 566), and regional market expenses (FERC account 575).

⁵ In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that large costs related to energy purchases are sometimes reported in this category.



3.2.2 Scale Variables

Two “classic” measures of utility output were utilized in our O&M benchmarking work: the annual average number of customers served and the total annual megawatt hours of net generation. Simply put, the greater the number of customers and generation output, the higher is the cost. The parameters of both of these variables are therefore expected to have a positive sign. An additional variable that varies with operating scale, generation capacity, is discussed further below.

3.2.3 Input Prices

The economic theory of production cost also suggests that the prices paid for production inputs are relevant business condition variables. We therefore included in the model an index of the prices that VIEUs pay for non-fuel O&M inputs. In estimating the model we divided cost by this input price index, a common practice in econometric cost research.

The O&M input price index was developed by PEG Research and is a weighted average of price indexes for labor and materials and services. The labor price index was constructed from BLS data. Occupational Employment Statistics (“OES”) data for 2008 were used to construct average wage rates for each utility’s service territory. These were calculated as a weighted average of the OES pay level for each job category using weights that correspond to the electric power generation, transmission, and distribution sector of the U.S. economy. Values for other years were calculated by adjusting the level in the focus year for the estimated change in the regional salaries and wages of utility workers. These estimates were constructed from BLS employment cost indexes.

Prices for material and service (“M&S”) O&M inputs were assumed to have a 25% local labor content on average and therefore tend to be a little lower in regions with low labor prices. They are escalated by a summary M&S input price index constructed by PEG Research from detailed electric utility M&S price indexes that were calculated by Global Insight and published in its *Power Planner*. The O&M input price for each utility was constructed by combining the labor and non-labor prices using utility-specific cost-share weights.



3.2.4 Other Variables

Eight other variables were included in the O&M cost model. Six of these pertain to power generation. One of these is the total nameplate generation capacity that is owned by the company. This capacity, which is measured in megawatts, is an important supplemental cost driver because O&M of capacity is needed even when it is idle. Our capacity measures were processed from data on individual power plants obtained from Form EIA 860 and predecessor sources. Our research team aggregated the nameplate capacity of each sampled utility's operational power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher the amount of generation capacity. The parameter for this variable should therefore have a positive sign.

The model contains four variables that measure the *mix* of generation capacity that a utility owns. One such variable is the share of the capacity that is nuclear fueled. Another is the share of combustion turbines ("CTs") in the capacity. These turbines are conventionally fueled by clean-burning natural gas. A third variable is the share of other capacity that uses clean energy resources. This includes gas-fired steam turbine and combined cycle plants and wind turbines. A fourth capacity mix variable is the share of capacity that burns low-cost sub-bituminous coal. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating plant that companies own. We expect cost to be higher the higher is the share of generation capacity that is nuclear fueled and the lower is the share of CTs and other units that are powered by clean energy resources. The parameters for the percent nuclear variable should therefore be positive, whereas the parameters for the other two variables should be negative. We cannot predict the sign for the sub-bituminous coal variable because this coal is a solid fuel but has a low sulfur content.

The sixth generation-related variable in the model is the average age of generation plant. We expect older plant to involve higher O&M expenses. The parameter for this variable should therefore have a positive sign.

One additional model variable addresses conditions that affect the cost of providing power delivery services. That is the number of customers per transmission line mile.⁶ The

⁶ Due to data limitations the value of this variable is frozen at its 1999 value for all companies in the model's estimation.



source of our transmission line mile data is McGraw-Hill's *Directory of Electric Power Producers and Distributors*. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. Other things being equal, we would expect that utilities with higher customer densities would have lower O&M expenses than utilities that need more extensive transmission facilities to serve the same number of customers. The parameter for this variable should therefore have a negative sign.

The O&M model also contains a trend variable. This permits predicted cost to change over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model.

3.2.5 Parameter Estimates

Estimation results for the O&M cost model are reported in Table 3. Due to the chosen form of the cost function, the parameter estimates for the output variables are the corresponding elasticities of cost with respect to these variables.⁷ These are useful in the construction of the unit cost index.

Table 3 also reports the values of the t statistic and p value that correspond to each parameter estimate. These test statistics 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. This statistical test requires the selection of a critical value for the test statistic. In this study, we employed critical values that are appropriate for a 90% confidence level given a large sample. The critical value of the t statistic corresponding to this confidence level was about 1.65. The critical value of the p value was 0.10. Any parameter estimate with a t-statistic greater than or equal to 1.65 in absolute value and a p-value less than or equal to 0.10 is statistically significant at our chosen confidence level. The test statistics were used in model specification. All cost driver variables other than trend variables were required to have statistically significant parameter estimates.

⁷The functional form issue is discussed further in the Appendix.

Table 3

ECONOMETRIC MODEL OF NON-FUEL O&M COST

Variable Key

N = Number of Retail Customers
 V = Net Generation
 CAP = Total Generation Capacity
 NG = % Nuclear Generation Capacity
 CT = % Combustion Turbine Capacity
 OC = % Clean Capacity Other Than CT
 SB = % Sub-bituminous Coal Capacity
 AGE = Steam Generation Plant Age
 NMT = Customers per Transmission Line Mile
 Trend = Trend Variable

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC	P-VALUE
N	0.536	23.73	0.00
V	0.128	4.64	0.00
CAP	0.248	8.43	0.00
NG	0.061	13.81	0.00
CT	-0.032	-4.48	0.00
OC	-0.052	-7.23	0.00
SB	-0.036	-4.60	0.00
AGE	0.136	3.37	0.00
NMT	-0.043	-2.93	0.00
Trend	-0.000	-0.03	0.98
Constant	8.302	486.78	0.00
R-squared	0.966		
Number of Observations	720		
Sample Period	1995-2010		

Examining the results in Table 3, it can be seen that all of the O&M cost model parameter estimates were plausible as to sign and magnitude. Cost was found to be higher the higher were the two “classic” output variables. At the sample mean, a 1% rise in the number of customers was estimated to raise cost by about 0.54%; a 1% rise in the generation volume was estimated to raise cost by about 0.13%; and a 1% rise in generation capacity was estimated to raise cost by 0.25%.

The parameter estimates for the other cost drivers included in the model were also sensible and indicate the following:

- Cost was higher the greater was the share of capacity that was nuclear-fueled.
- Cost was lower the greater was the share of combustion turbines in the generation capacity.
- Cost was also lower the greater was the share of other capacity powered by clean energy resources.
- Cost was lower the greater was the share of generation capacity fueled by sub-bituminous coal.
- Cost was higher the higher was steam generation age.
- Cost was lower the greater was the number of customers per transmission line mile.
- The estimate of the trend variable parameter suggests there was essentially no shift in cost each year for reasons other than the trends in the business condition variables.

The table also reports the R squared statistic for the model. This statistic measures the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.97, suggesting that the explanatory power of the model was quite high.

3.2.6 OG&E’s Business Environment

OG&E is a vertically integrated electric utility based in Oklahoma City. The heart of its service territory is the Oklahoma City metropolitan area, which has a population of more than 1.2 million people. The company also serves scattered areas to the north, south, and east of the



metro area, including an area of western Arkansas which includes Fort Smith. In total, OG&E currently serves about 775,000 customers in a region of about 30,000 square miles.

The Company produces most of the power that it supplies to customers. This power is produced chiefly from comparatively clean energy resources such as natural gas. OG&E also has plants that burn low cost sub-bituminous Western coal. These plants do not currently require expensive sulfur removal facilities to comply with government emissions policies because of the low sulfur content of the coal. The gas-fired generating units, which are mostly combined cycle units and older steam turbines, involve lower capital cost than solid-fuel generation and are useful for meeting the pronounced demand surges that occur on the southern plains in the hot summer months.

The Company operates approximately 4,300 miles of transmission lines in Oklahoma and Arkansas. Operational authority over the transmission system has been transferred to the Southwest Power Pool (“SPP”) RTO. The SPP provides dispatching, planning, and regional market services. It charges OG&E for network integrated transmission service, and these charges are reported by the Company as O&M expenses.

Table 4 compares OG&E’s 2008-2010 average values for O&M cost and the identified cost drivers to the corresponding sample mean values. The cost for OG&E includes an upward adjustment of about \$5.9 million to normalize the cost of a generation maintenance contract. It can be seen that the O&M expenses of OG&E were only 0.66 times the sample mean. In other words, cost was about 34% below the mean. The number of customers served was, meanwhile, 0.89 times the mean, while the generation volume was 1.02 times the sample mean and total generation capacity was 1.22 times the sample mean. Thus, cost was well below the mean despite measures of operating scale that were much closer to the mean and in one respect well above it. Turning next to input prices, Table 4 shows that the O&M input prices faced by OG&E were very close to the mean, and a little below.



Table 4

COMPARISON OF OG&E'S O&M BUSINESS CONDITIONS TO SAMPLE NORMS, 2008-2010

Business Condition	Units	Sample Mean	OG&E	OG&E / Sample Mean
Bundled Power Service O&M Cost	Dollars (\$000)	438,532	288,467	0.66
Number of Retail Customers	Count	873,389	773,655	0.89
Total Net Generation	MWh	24,910,510	25,438,533	1.02
Total Generating Capacity	MW	6,256	7,633	1.22
O&M Input Price Index	Index Number	101.7	100.1	0.98
Share of Capacity Nuclear	Percent	4.8%	0.0%	0.00
Share of Capacity that is Combustion Turbines	Percent	17.1%	3.9%	0.23
Share of Capacity Other Clean	Percent	25.8%	58.7%	2.28
Share of Capacity Sub-bituminous Coal	Percent	18.6%	37.4%	2.01
Age of Plant	Years	33.7	32.9	0.98
Customers per Transmission Line Mile	Customers per Mile	220	163	0.74

As for the other cost driver variables, the shares of nuclear generation and combustion turbines in total capacity were well below the sample mean and the shares of generation capacity powered by other clean energy resources and of capacity that burned sub-bituminous coal were both well above the mean. The age of generation plant was very similar to the mean and a little below. The number of customers per transmission line mile was considerably below the mean, suggesting that the Company had an above average transmission workload.

3.2.7 Econometric Benchmarking Results

Using the econometric O&M benchmarking model, the Company's cost was on average about 20% below its predicted value over the 2008-2010 period. This was a top quartile score. In other words, more than three quarters of the sampled utilities had costs that compared less favorably to their econometric benchmarks. The Company's cost was found to be about 12% below its predicted value in 2010. This was also a top quartile score.

3.2.8 Unit Cost Results

Based on the econometric work, we have chosen the following five utilities for the O&M unit cost peer group:

Cleco
Entergy Mississippi
Public Service of Oklahoma
Southwestern Electric Power
Southwestern Public Service

These companies face several cost drivers that are similar to those of OG&E. For example, they tend to

- face labor prices below the sample average;
- have no nuclear capacity;
- use extensive amounts of natural gas and low-sulfur sub-bituminous coal in generation; and
- have transmission line miles that are large relative to the number of customers served due to a low to intermediate level of service territory urbanization.



Table 5 summarizes key results of our unit cost comparisons to the peer group for the years 2008-2010. There are results for the cost, output quantity, and unit cost indexes. Results are presented for each of the three most recent years for which data are available for all companies. An average of these three years is also displayed.

For the average of the 2008-2010 period, we find that OG&E's *unit* cost was therefore a substantial 23% below the mean. OG&E's cost was about 44% above the peer group norm, while its output index was about 86% above the peer group norm. Unit cost was about 19% below the peer group mean in 2010. These results corroborate the findings of our econometric benchmarking research and suggest that OG&E has been a superior O&M cost performer in recent years, including 2010.

3.3 Benchmarking OG&E's Generation Maintenance Expenses

3.3.1 Definition of Variables

Cost

The O&M expenses addressed in our second benchmarking exercise were the maintenance expenses for fossil steam generation and "other" power generation. These are reported in FERC accounts 510-514 and accounts 551-554, respectively. The great bulk of the expenses for other power generation that utilities report on FERC Form 1 are incurred in the maintenance of gas-fired power plants. However, small expenses for the maintenance of wind-powered and/or miscellaneous other (*e.g.* wood-burning) generation facilities are reported in this category for a few utilities, including OG&E.

Operating Scale

Three scale-related variables were utilized in our maintenance cost benchmarking work: the nameplate capacity of applicable (*i.e.* non-nuclear and non-hydro) generation [in megawatts ("MWs")] owned by the company and the volumes of fossil steam and other generation [both



Table 5

**HOW THE O&M UNIT COST OF OG&E
COMPARED TO PEER GROUP NORMS, 2008-2010**

Year	Index*			% Difference
	Cost	Output	Unit Cost Level	
2008	1.407	1.873	0.751	-24.9%
2009	1.419	1.889	0.751	-24.9%
2010	1.490	1.827	0.815	-18.5%
Averages	1.439	1.863	0.773	-22.7%

Peer group consists of Cleco, Entergy Mississippi, Public Service Company of Oklahoma, Southwestern Electric Power, and Southwestern Public Service.

* Each index number is a bilateral comparison of the metric for OG&E to the mean for a peer group. The index number is the ratio of the OG&E value to the peer group mean.

measured in megawatt hours (“MWhs”)].⁸ The generation volumes were obtained from FERC Form 1. Data on capacity are discussed in Section 3.2.4 above. Cost is in theory higher the higher is a company’s output. The parameters of all of these variables should therefore have a positive sign.

Input Prices

Pursuant to cost theory, we also included in the generation maintenance cost model a summary index of the prices of generation maintenance O&M inputs. The summary generation maintenance input price index was constructed using data and methods analogous to those described in Section 3.2.3 for O&M expenses. In estimating model parameters we once again divided cost by this input price index.

Other Variables

Five other variables were included in the generation maintenance cost model. Most are concerned with the mix of generation capacity owned. One capacity mix variable is the share of combustion turbines in the applicable generating capacity. CTs use clean-burning fuels such as natural gas. Another variable is the share of other capacity that uses clean energy resources. Coal- and resid-fired generating stations are more costly to maintain because they involve greater fouling and slagging of boilers, and require complicated facilities for fuel unloading, storage, handling, processing, and ash disposal.¹⁰ We therefore expect the parameters of both of these variables to have a negative sign. Another capacity mix variable is the percentage of applicable capacity that is fueled by sub-bituminous coal. The sign of this parameter is difficult to predict because sub-bituminous coal is a solid fuel but has a lower sulfur content than most solid fuels.

A fourth additional cost-driver variable in the model is the percentage of fossil-fueled generating capacity that doesn’t have sulfur dioxide (“SO₂”) scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. We expect that maintenance expenses will be lower the lower is the percentage of

⁸ The metrics for capacity and other generation volume include some wind power for several sampled utilities, including OG&E.

¹⁰ The higher cost of maintenance is typically more than offset by the lower cost of fuel.



generating capacity that does not have scrubbers. The parameter for this variable should therefore have a negative sign. The econometric model also contains a trend variable.

3.3.2 Parameter Estimates

Estimation results for the maintenance cost model are reported in Table 6. It shows that all of the cost model parameter estimates are plausible as to sign and magnitude. Maintenance cost was found to be higher the higher were all three scale-related variables. At the sample mean, a 1% rise in generation capacity was estimated to raise cost by about 0.66%. A 1% rise in the volume of steam generation was estimated to raise cost by about 0.15%, whereas a 1% rise in the other generation volume was estimated to raise cost by about 0.03%.

The parameter estimates for the other cost drivers included in the model were also sensible and indicate the following:

- Maintenance expenses were lower the higher were the shares of capacity that were CTs, other generation powered by clean resources, or were fueled by sub-bituminous coal.
- Cost was also lower the greater was the share of generation capacity that was unscrubbed.
- The estimate of the trend variable parameter suggests a 1.7% annual increase in cost for reasons other than the trends in the business condition variables.

Table 6 also reports the R squared statistic for the model. Its value was about 0.88, suggesting that the explanatory power of the model was high.

3.3.3 Business Conditions of OG&E

OG&E's large fleet of generating plants are of diverse character and include coal-fired steam turbines ("STs") (Muskogee units 4-6 and Sooner), gas-fired STs (Horseshoe Lake, Muskogee 3, Mustang, and Seminole), gas-fired combined cycle plants (*e.g.* McClain and Redbud), several gas-fired combustion turbines, and two wind farms. The coal-fired units were noted above to burn low-sulfur coal and do not have sulfur removal facilities.



Table 6

ECONOMETRIC MODEL OF GENERATION MAINTENANCE COST

Variable Key

SG = Net Fossil Steam Generation (MWh)
 OG = Net Other Generation (MWh)
 CAP = Total Fossil Steam and Other Generation Capacity (MW)
 CT = % Capacity Combustion Turbines
 OC = % Capacity Other Clean
 SB = % Capacity Sub-bituminous Coal
 NS = % of Generation Capacity Not Scrubbed
 Trend = Trend Variable

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC	P-VALUE
SG	0.149	4.02	0.000
OG	0.025	12.69	0.000
CAP	0.664	17.81	0.000
CT	-0.185	-15.69	0.000
OC	-0.161	-11.61	0.000
SB	-0.020	-2.76	0.006
NS	-0.091	-4.76	0.000
Trend	0.017	10.89	0.000
Constant	6.718	245.10	0.000
R-squared	0.875		
Number of Observations	864		
Sample Period	1995-2010		

The youngest gas-fired ST is thirty-five years old, while the oldest is sixty years old. The coal fired units were built between 1977 and 1984. The youngest coal-fired unit is thus a little more than twenty-six years old, while the oldest is thirty-three years old. The Company is experiencing a significant aging of its generating fleet, in common with most VIEUs in the U.S. today. This should tend to put upward pressure on maintenance costs over time.

A classic text on power plant technology notes that the mature phase in the life of a power plant typically lasts between twenty-five and thirty years.

Following this phase, the aging process becomes noticeable. Forced outages and maintenance costs increase, and availability declines. Component end of life usually causes the higher forced outage rate. Occasional operational error and the degradation of boiler components due to erosion, corrosion, creep, and fatigue lead to localized failures. The forced outage rate steadily increases during this phase unless major overhauls or component replacements are instituted.¹¹

Table 7 compares the 2008-2010 average values of the generation maintenance cost model business conditions for OG&E to the sample mean values of these variables during the same years. The cost for OG&E includes the same \$5.9 million upward adjustment that we applied to O&M expenses to normalize the cost of a generation maintenance contract. It can be seen that the maintenance cost of OG&E was about 0.92 times the sample mean. In other words, cost was about 8% below the mean. Applicable generation capacity was about 1.46 times the mean, whereas fossil steam generation volume was 1.25 times the mean and other power generation volume was 1.41 times the mean. Thus, OG&E's maintenance cost was modestly below the sample mean despite the fact that all three dimensions of operating scale were well above the mean. Turning next to input prices, the table shows that the generation maintenance input prices faced by OG&E were quite close to the mean, and a little below.

As for the other business condition variables, the share of combustion turbines in the applicable capacity was well below the mean, whereas the capacity shares of other generation powered by clean energy resources, and of generation fueled by sub-bituminous coal, were well above the mean. The share of capacity that was unscrubbed was well above the mean.

¹¹ S.C. Stultz and J.B. Kitto, eds. *Steam: Its Generation and Use* Fortieth Edition (Barberton, OH: Babcock and Wilcox, 1992).

Table 7

COMPARISON OF OG&E'S GENERATION MAINTENANCE BUSINESS CONDITIONS TO SAMPLE NORMS, 2008-2010

Business Condition	Units	Sample Mean	OG&E	OG&E / Sample Mean
Fossil Generation Maintenance Cost	Dollars (\$000)	73,170	67,359	0.92
Generation Maintenance Input Price Index	Index	101.9	99.8	0.98
Applicable Generation Capacity	MW	5,225	7,633	1.46
Net Fossil Steam Generation	MWh	16,372,408	20,409,831	1.25
Net Other Generation	MWh	3,577,869	5,028,703	1.41
Share of Capacity Combustion Turbines	Percent	16.4%	3.9%	0.24
Share of Capacity Other Clean	Percent	24.9%	58.7%	2.35
Share of Capacity Sub-bituminous Coal	Percent	22.7%	37.4%	1.64
Share of Capacity Not Scrubbed	Percent	71.7%	100.0%	1.40

3.3.4 Econometric Benchmarking Results

Using the econometric generation maintenance cost model, OG&E's cost was found to be about 25% below the cost predicted by the model on average over the 2008-2010 period. This was a top quartile score. In 2010 the Company's cost was about 4% below the model's prediction. This was a second quartile score.

3.3.5 Unit Cost Results

In this study we used the econometric results to choose a generation maintenance cost peer group consisting of the following four utilities:

Entergy Arkansas
Northern States Power - Minnesota
Public Service of Oklahoma
Southwestern Public Service

These companies were chosen on the basis of the similarity of key generation-maintenance cost drivers to those facing OG&E. All companies relied primarily on sub-bituminous coal- and gas-fired generation during the 2008-2010 period and scrubbed a comparatively small share of their emissions for sulfur. Entergy Arkansas and Northern States Power ("NSP") were not used as peers in the O&M unit cost benchmarking because they have nuclear operations. This is not a concern in our generation maintenance benchmarking study because costs of nuclear (and hydroelectric) generation maintenance are itemized for easy removal. Our ability to use data for Entergy Arkansas and NSP make it unnecessary to use as peers three other utilities --- Cleco, Southwestern Electric Power, and Entergy Mississippi --- that were peers in the O&M work but have fossil generation mixes less similar to OG&E's.

The unit cost indexes used to benchmark generation-maintenance cost summarize comparisons for three scale measures: the applicable generation capacity and the volumes of fossil steam generation and other power generation. The weights are based on cost elasticity estimates for these variables that are drawn from the econometric cost model.

Table 8 summarizes key results of our unit cost comparisons to the peer group. There are results for the cost index, the output quantity index, and unit cost. Results are presented for 2008, 2009, and 2010. An average of the results for these three years is also displayed.



Table 8

**HOW THE GENERATION MAINTENANCE UNIT COST
OF OG&E COMPARED TO PEER GROUP NORMS, 2008-2010**

Year	Index*			% Difference
	Cost	Output	Unit Cost Level	
2008	1.189	1.672	0.711	-28.9%
2009	1.263	1.706	0.740	-26.0%
2010	1.583	1.768	0.896	-10.4%
Averages	1.34	1.72	0.78	-21.8%

Peer group consists of Entergy Arkansas, Northern States Power-Minnesota, Public Service Company of Oklahoma, and Southwestern Public Service.

* Each index number is a bilateral comparison of the metric for OG&E to the mean for a peer group. The index number is the ratio of the OG&E value to the peer group mean.

We find that on average over the three years OG&E's *unit* cost was about 22% below the peer group mean on average. OG&E's generation maintenance cost was about 34% above the peer group norm over the three years while its output was about 72% above the norm. In 2010, OG&E's unit cost was about 10% below the peer group mean. Using both benchmarking methods, we therefore found that OG&E's 2010 generation maintenance expenses, while higher than in the previous two years, were still quite reasonable.



Appendix

This section provides additional and more technical details of our benchmarking work. We first address the form of the cost model and our econometric work. There follows a discussion of the unit cost indexes.

A.1 Econometric Research

A.1.1 Form of the Econometric Cost Models

Specific forms must be chosen for cost functions used in econometric research. The linear and the double-log forms are commonly employed. The cost model presented on p. 6 is an example of a linear cost model:

$$C = a_0 + a_1 * N + a_2 * W \quad [A1]$$

Cost is a linear function of the number of customers served and the wage rate.

Here is an analogous cost model of double-log form:

$$\ln C = a_0 + a_1 * \ln N + a_2 * \ln W \quad [A2]$$

In this form, the value of each cost driver has been converted to its natural logarithm. This specification has the effect of making the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers. When model data are mean-scaled for convenience, each parameter is the elasticity of cost with respect to the basic variable at sample-mean values of the business conditions.

One disadvantage of the double-log form is that variables cannot have zero values. Since several of the cost-driver variables in our study (*e.g.* the share of CTs in generation capacity) have zero values, we have elected to use a linear treatment for these variables and a logged treatment for the other variables, which include the output variables. The functional forms of the two models are therefore hybrids.



A.1.2 Estimation Procedure

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. It reflects imperfections in the development of the model. The imperfections may include any or all of the following: poor measurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the functional relationship. Error terms are a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. It is customary to assume that error terms are random variables with probability distributions that are determined by additional parameters, such as mean and variance, the values of which can be estimated. This opens the door to various kinds of statistical inference, such as hypothesis tests concerning the statistical significance of parameter estimates.

A variety of estimation procedures (aka “estimators”) are used in econometric research. The appropriateness of each procedure depends on the assumptions made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares (“OLS”), is readily available in over the counter econometric software. Another class of procedures, called generalized least squares (“GLS”), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scales. Estimation procedures that address several of the error term issues that are routinely encountered in utility cost benchmarking are not readily available in commercial econometric software packages. They instead require the development of customized estimation programs.

In our research for OG&E, we corrected for autocorrelation and heteroskedasticity in the error terms using a custom in-house estimation procedure developed with Gauss software. Since



we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (“MLEs”).¹² Our estimates thus possess all the highly desirable properties of MLEs.

Note, finally, that the model specification was determined using the data for all sampled companies, including OG&E. However, computation of model parameters and standard errors for the cost predictions required that the values for OG&E be dropped from the sample. The estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

A.2 Unit Cost Indexes

The unit cost indexes are designed to compare the unit cost of OG&E to the norm for a peer group. Each unit cost index is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{Output\ Quantity_{OG\&E,t}} \quad [A3]$$

The cost index for OG&E in each year t is defined by the formula

$$Cost\ Index_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{\overline{Cost}_t} \quad [A4]$$

where \overline{Cost}_t is the mean value of cost for the peer group in year t .

The output quantity index in each year t was defined by the formula

$$Output\ Quantity_{OG\&E,t} = \sum_i se_i * \frac{Y_{OG\&E,i,t}}{Y_{i,t}}. \quad [A5]$$

Here,

$Y_{OG\&E,i,t}$ = Quantity of output variable i for OG&E

$Y_{i,t}$ = Peer group mean of the quantity of output variable i .

se_i = Share of output variable i in the sum of the econometric estimates of the cost elasticities of the output quantities under sample mean values of the business conditions.

¹² See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

In the O&M model, the elasticities of cost with respect to the number of customers served, net generation, and generation capacity were estimated to be .536, .128, and .248, respectively. The corresponding elasticity-share weights for the output index were 58.8%, 14.0%, and 27.2% respectively. In the generation maintenance model, the elasticities of cost with respect to the volumes of fossil steam and other generation and generation capacity were estimated to be .149, .025, and .664 respectively. The corresponding elasticity-share weights for the output index were 17.8%, 3.0%, and 79.2%, respectively.

Equations [A3], [A4], and [A5] imply that

$$Unit\ Cost_{OG\&E,t} = \left(\frac{Cost_{OG\&E,t}}{Cost_t} \right) \bigg/ \left(\sum_i se_i * \frac{Y_{OG\&E,i,t}}{Y_{i,t}} \right). \quad [A6]$$

The percentage difference between the unit cost of OG&E and that of the peer group is then calculated using the formula $100 * (Unit\ Cost_{OG\&E,t} - 1)$.



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