

Lowry

BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF COLORADO

\*\*\*\*\*

IN THE MATTER OF ADVICE LETTER )  
NO. 1535 FILED BY PUBLIC SERVICE )  
COMPANY OF COLORADO TO REVISE )  
ITS COLORADO PUC NO. 7 ELECTRIC )  
TARIFF TO REFLECT REVISED RATES )  
AND RATE SCHEDULES TO BE )  
EFFECTIVE ON JUNE 5, 2009. )

DOCKET NO. 09AL-299E

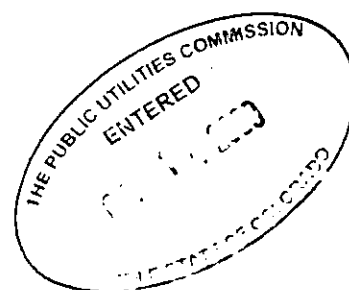
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REBUTTAL TESTIMONY AND EXHIBIT OF MARK NEWTON LOWRY

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO



October 13, 2009

## LIST OF EXHIBITS

Exhibit No. MNL-1	Statistical Support for Public Service Company of Colorado's Forward Test Year Proposal
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OF THE STATE OF COLORADO**

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**REBUTTAL TESTIMONY AND EXHIBIT OF MARK NEWTON LOWRY**

**I. INTRODUCTION AND QUALIFICATIONS**

2     **Q.     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3     A.     My name is Mark Newton Lowry. My business address is 22 E. Mifflin St., Suite  
4             302, Madison, WI 53703.

5     **Q.     BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

6     A.     I am the President of Pacific Economics Group ("PEG") Research LLC, a  
7             company in the Pacific Economics Group consortium that specializes in  
8             incentive regulation and cost research for the energy utility industry.

9             Our personnel, which include three PhD economists, have more than fifty  
10            man-years of experience in these fields, which share a foundation in economic  
11            statistics. Our practice is international in scope and has to date included

1 projects in twelve countries. Most of our staff was trained at the University of  
2 Wisconsin, which is renowned for its strength in economic statistics.

3 A diverse mix of utilities and regulators has given our practice a  
4 reputation for objectivity and dedication to economic science. For example, we  
5 have advised the Canadian Electricity Association and major Canadian electric  
6 utilities on benchmarking issues for many years, but we also benchmark more  
7 than 80 power distributors in the Canadian province of Ontario each year for the  
8 Ontario Energy Board. I am currently working for Public Service Company of  
9 Colorado ("Public Service" or the "Company") in this proceeding, but last year  
10 submitted an (unsuccessful) bid to advise this Commission on incentive  
11 regulation.

12 **Q. PLEASE BRIEFLY EXPLAIN YOUR DUTIES AND RESPONSIBILITIES?**

13 A. In addition to my managerial responsibilities as the President of PEG Research,  
14 I supervise benchmarking and other kinds of utility cost research, design  
15 incentive regulation plans, and provide expert witness testimony.

16 **Q. HAVE YOU APPEARED AS AN EXPERT WITNESS IN OTHER UTILITY  
17 PROCEEDINGS?**

18 A. Yes. I have testified many times on benchmarking and incentive regulation  
19 issues. Most of my testimony has involved statistical cost research. Venues for  
20 my testimony have included Alberta, British Columbia, California, Georgia,  
21 Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New  
22 York, Ontario, Quebec, Rhode Island, and Vermont. My resume is attached as  
23 Attachment A.

1 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

2 A. I am appearing on behalf of Public Service Company of Colorado ("Public  
3 Service" or "Company")

4 II. PURPOSE OF TESTIMONY

5 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

6 A. Public Service recently filed for an increase in their base rates that recover the  
7 cost of its nonfuel inputs, excluding purchased power costs, demand-side  
8 management costs, the incremental costs of complying with the state of  
9 Colorado's renewable energy standards, and certain costs of incremental  
10 transmission investments. The Company has used a forward test year ("FTY")  
11 to calculate its proposed revenue requirement. In their Answer Testimony,  
12 various intervenors expressed concerns about the difficulty of verifying the  
13 reasonableness of a FTY revenue requirement and the impact of a FTY on  
14 utility incentives to operate efficiently.

15 Public Service has retained PEG Research to help substantiate its FTY filing  
16 in two ways. One is to benchmark the company's proposed 2010 O&M  
17 expenses – one of the most important sources of uncertainty in the rate filing.  
18 The other is to use our statistical methods and the same sample used in our  
19 benchmarking work to consider whether FTYs weaken utility performance  
20 incentives.

21 Q. WHY IS A FOCUS ON THE COMPANY'S PROPOSED O&M EXPENSES  
22 APPROPRIATE?

1 A. Where utilities are subject to cost-of-service rates, a utility's ability to effectively  
2 manage its costs is an important consideration for the Commission in setting  
3 rates. O&M expenses are the largest component of a utility's cost structure that  
4 a utility can attempt to control in the short run. They are also one of the biggest  
5 sources of intervenor uncertainty regarding a utility's projections.

6 Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER  
7 COMPANY WITNESSES?

8 A. Company witness Mr. Scott Wilensky is providing an explanation of why the  
9 Company's proposed 2010 expenses are reasonable in light of historical trends.  
10 My testimony and the attached study, Exhibit No. MNL-1, provide a quantitative  
11 assessment of the reasonableness of these expenses, which is based almost  
12 entirely on research on the costs of *other* utilities. My study of the incentive  
13 impact of FTYs is, similarly, an attempt to shed some light from a national  
14 perspective on this important issue, which Mr. Wilensky discusses in more  
15 qualitative terms.

16 Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR O&M COST  
17 PERFORMANCE STUDY?

18 A. Using two well established statistical benchmarking methods, my study prompts  
19 me to conclude that the Company's proposed 2010 test-year O&M expenses  
20 are low by industry standards.

1 Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE FTY  
2 INCENTIVES RESEARCH?

3 A. After examining differences in the unit cost trends of the utilities operating under  
4 different types of test years – i.e., historic or forward – I find no support for the  
5 assertion that forward test years weaken performance incentives.

6 III. REASONABLENESS OF 2010 O&M EXPENSES

7 Q. WHAT IS STATISTICAL BENCHMARKING AND HOW IS IT USEFUL IN  
8 MEASURING UTILITY PERFORMANCE?

9 A. Statistical benchmarking uses statistics to establish benchmarks that can be  
10 used in quantitative performance appraisals. Cost benchmarks can be used to  
11 gauge a particular utility's efficiency. The primary set of statistics used to  
12 establish cost benchmarks is utility operating data. This data is available from  
13 the many forms and reports that utilities file with federal government agencies.

14 Accurate benchmarking is complicated because the costs of utilities vary  
15 more because of differences in the business conditions they face than because  
16 of differences in their operating efficiency. A cost benchmark for a particular  
17 utility should, therefore, reflect the typical performance that might be expected of  
18 managers given the local business conditions, which that particular utility faces.  
19 Statistical cost research can identify important cost drivers and use such cost  
20 drivers to establish better performance metrics and benchmarks.

21 Q. WHAT COMPONENT OF THE COMPANY'S COST DID YOU ADDRESS IN  
22 YOUR STUDY?



1 A. As mentioned above, we addressed the efficiency inherent in the Company's  
2 proposed non-fuel O&M expenses for 2010. In the study, cost was defined as  
3 total O&M expenses less expenses for generation fuels, purchased power,  
4 employee pensions and benefits, transmission dispatching, transmission  
5 services by others, and regional market management. Expenses were excluded  
6 from the study if they were not base rate costs, were uncharacteristically  
7 volatile, and/or were substantially beyond the Company's control. For example,  
8 pension contributions were excluded because, for many companies, they swing  
9 wildly with changes in stock market prices.

10 Q. PLEASE SUMMARIZE THE BENCHMARKING METHODS THAT YOU USED  
11 IN YOUR STUDY OF PUBLIC SERVICE.

12 A. The proposed expenses were appraised using two well-established  
13 benchmarking methods: econometric modeling and unit cost indexing. The  
14 econometric modeling we did involved the use of a model designed to explain  
15 the impact of various quantifiable business conditions on the non-fuel O&M  
16 expenses of vertically integrated electric utilities. The parameters of the model,  
17 which measure cost impact, were estimated statistically using historical data on  
18 utility operations. A model fitted with econometric parameter estimates and the  
19 specific business conditions that Public Service expects to face in 2010 was  
20 used to generate cost benchmarks.

21 The other benchmarking method we employed involved the comparison of  
22 the base rate O&M expenses of Public Service to those of other utilities using

1 unit cost indexes. A unit cost index is the ratio of a cost index to an output  
2 index. Estimates of cost elasticities from our econometric work were used to  
3 design a unit cost index that is a weighted average of comparisons using  
4 simpler metrics that individually feature generation volume, generation capacity,  
5 and the number of customers served. We compared the unit costs of Public  
6 Service in 2010 with the 2008 costs for all sampled utilities and for sampled  
7 utilities in the Western Interconnection.

8 The study was based on a sample of high-quality data for forty-eight  
9 vertically integrated U.S. electric utilities. The sample period for the  
10 econometric and indexing work was 1995 to 2008. The sample permitted the  
11 development of a credible cost model. All data were drawn from respected  
12 public sources such as the Federal Energy Regulatory Commission ("FERC")  
13 Form 1. The model had high explanatory power and all estimates of the key  
14 model parameters were plausible and highly significant.

15 **Q. WHAT ARE THE KEY EMPIRICAL RESULTS?**

16 A. The proposed non-fuel expenses of Public Service were found to be more than  
17 17% below the benchmark generated by our econometric cost model. This  
18 performance is normally commensurate with a top quartile status in our  
19 research. Public Service's unit cost index was about 16% below the mean for  
20 the full sample and 24% below the mean for utilities in the Western  
21 Interconnection. We conclude that the Company's proposed expenses are  
22 remarkably low by industry standards.



1     **IV. IMPACT OF FORWARD TEST YEARS ON UTILITY OPERATING EFFICIENCY**

2     **Q.     PLEASE SUMMARIZE THE METHODS YOU USED TO STUDY THE**  
3     **INCENTIVE IMPACT OF FORWARD TEST YEARS.**

4     A.     We compared the trends, over the 1995-2008 period, in the unit cost of the  
5     utilities in our sample that operated under historic and forward test years. As in  
6     the benchmarking work, we considered cost per customer, cost per MWh of  
7     generation, and cost per MW of generation capacity, as well as a summary unit  
8     cost index. We used unit cost metrics in order to control for different trends in  
9     the workload of the utilities. The sample included 31 utilities operating under  
10    historic test years and 9 utilities operating under future or forward test years.

11   **Q.     WHAT WERE THE KEY EMPIRICAL RESULTS?**

12   A.     The unit cost index for forward test years grew at a 1.6% average annual rate  
13   whereas the unit cost index for historic test year utilities grew at a 2.2% average  
14   annual rate. The utilities operating under *forward* test years thus experienced  
15   unit cost growth trends that were very similar to (and a little slower than) those  
16   of utilities operating under historic test years. The results of this research  
17   support the view that a forward test year does not erode utility incentives to  
18   operate efficiently. This squares with my conviction, developed over almost two  
19   decades of incentive regulation research, that the type of test year does not  
20   significantly drive performance incentives in a regulatory system.

21   **Q.     DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?**

22   A.     Yes, it does.

# STATISTICAL SUPPORT FOR PUBLIC SERVICE OF COLORADO'S FORWARD TEST YEAR PROPOSAL

13 October 2009

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## **1. INTRODUCTION AND SUMMARY**

### **1.1 Introduction**

Public Service of Colorado ("Public Service" or "the Company") recently filed for an increase in the base rates that recover the cost of its non-fuel inputs. The Company has used a forward test year ("FTY") to calculate its proposed revenue requirement. FTYs are allowed by law in Colorado but are not widely used and the Company's approach has been opposed by several witnesses in the Answer Testimony. Witnesses complain of the difficulty of verifying the reasonableness of an FTY revenue requirement. Some express concern about the impact of the FTY approach on utility performance incentives.

The personnel of Pacific Economics Group ("PEG") Research LLC have extensive experience in utility cost research and incentive regulation, fields with a common foundation in economic statistics. Testimony quality benchmarking studies are a company specialty. We pioneered the use of scientific benchmarking methods in North American regulation. Company president and senior author Mark Newton Lowry has testified on benchmarking and incentive regulation issues in numerous proceedings.

Public Service has retained PEG Research to help substantiate its FTY filing in two ways. One is to benchmark the company's proposed O&M expenses --- one of the most important sources of uncertainty in the rate filing. We were also asked to use statistical methods to address the issue of whether an FTY weakens utility cost performance incentives.

Following a brief summary of the work below, Section 2 provides an introduction to benchmarking methods. Section 3 discusses our empirical research for Public Service. Some technical details of the research are presented in the Appendix.

### **1.2 Summary of Research**

We addressed the reasonableness of the Company's forecasted 2010 O&M expenses using statistical benchmarking methods. For Public Service and all companies in the sample, cost was defined as total O&M expenses less reported expenses for fuel, purchased power, certain transmission services, regional market management, and pensions and

benefits. We also produced results with pension and benefit expenses included, although these are more difficult to benchmark accurately.

The 2010 expenses were appraised using two well established benchmarking methods: econometric modeling and unit cost indexing. Guided by economic theory, we developed a mathematical model of the impact that various quantifiable business conditions have on the base rate O&M expenses of vertically integrated electric utilities ("VIEUs") like Public Service. The parameters of the model, which measure cost impact, were estimated statistically using historical data on utility operations. A model fitted with econometric parameter estimates and the business conditions that Public Service expects to face in 2010 was used to benchmark the proposed test year expenses.

The econometric research was based on a sample of good quality data for 47 U.S. VIEUs. The sample period was 1995 to 2008. The sample is large and varied enough to permit the development of a highly credible cost model. The data used in model estimation were drawn from the Federal Energy Regulatory Commissions ("FERC") Form 1 and other respected public sources. All estimates of model parameters were plausible and highly significant. The non-fuel O&M expenses proposed by Public Service for 2010 were found to be more than 17% below the benchmark generated by the econometric model. This kind of performance is ordinarily commensurate with a top quartile ranking.

As for the unit cost benchmarking, we compared the proposed 2010 expenses of Public Service to the 2008 costs of sampled utilities using three simple unit cost metrics and a summary unit cost index. Comparisons were made to the full sample and the sampled utilities in the Western Interconnection. The unit cost implied by Public Service's 2010 forecast is well below those of both utility groups. We conclude from the assembled evidence that the proposed expenses reflect a good level of operating performance.

The same data set was used to consider the effect of alternative kinds of test years used in rate cases, on operating performance. We compared the trends, over the 1995-2008 period, in various O&M unit cost metrics for the utilities in our sample that operated under historic and forward test years. We found that utilities operating under forward test years had unit cost growth trends that were similar to (and a little slower than) those of utilities operating under historic test years. The results of this research support the view that an FTY does not erode utility cost containment incentives.



## 2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we provide a non-technical discussion of some important benchmarking concepts. The two benchmarking methods used in the study are explained. More technical details of our methodology are discussed in the Appendix.

### 2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. 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 more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise commonly involves one or more gauges of activity. These are sometimes called key performance indicators ("KPIs"). The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of Public Service and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

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

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in both the calculation of benchmarks and the comparison process. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. The values achieved by Hall of Fame members like John Elway are useful benchmarks. These values reflect a Hall of Fame performance standard.

## 2.2 External Business Conditions

For costs and many other kinds of business performance variables it is widely recognized that differences in the values of the variables that companies achieve depend partly on differences in operating efficiency and partly on differences in the business conditions that they face. In cost research these conditions are sometimes called cost “drivers”. The cost performance of a company depends on the cost that it achieves (or, in the case of Public Service, *proposes*) given the business conditions that it faces. Benchmarks must therefore reflect business conditions if they are to reflect a chosen performance standard faithfully.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. We begin by positing that the actual cost incurred by a company is the product of the minimum achievable cost and an efficiency factor.<sup>1</sup> The goal of cost benchmarking is then to accurately estimate the efficiency factor.

Consider now that, under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. When the focus of benchmarking is a subset of the entire series of inputs, the minimum cost depends on the prices of the included inputs, output quantities, and on the amounts of other inputs that the company uses. This means that a fair appraisal of the efficiency with which a utility uses a certain class of inputs must consider the amounts of other inputs it uses. For example, a utility’s *O&M* expenses depends on the quantities of different kinds of *capital* inputs that it owns.

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<sup>1</sup> Minimum achievable cost is a hypothetical notion and cannot be precisely calculated for specific utilities.

Whichever cost function is applicable, economic theory allows for the existence of *multiple* output variables. This is important because it is often impossible to accurately measure the workload of a utility using only one output variable. The cost of a vertically integrated electric utility like Public Service, for instance, depends on the number of customers that it serves as well as its generation volume. It is also noteworthy that the theory allows for the possibility that numerous business conditions other than input prices and output quantities can affect the minimum cost of service.

## **2.3 Benchmarking Methods**

In this section we discuss at some length the two benchmarking methods that we used in our study for Public Service: econometric modeling and unit cost indexing. The econometric approach is discussed first to establish a context for the discussion of the index approach.

### **2.3.1 Econometric Modeling**

#### ***Basic Assumptions***

Relationships between the costs of utilities and the business conditions that they face can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.<sup>2</sup> The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The sample used in model 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.

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 explanatory variables are generally

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<sup>2</sup> The act of estimating model parameters is sometimes called regression analysis.

assumed to be independent in the sense that their values are not influenced by the values of dependent 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: the mismeasurement 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 underlying 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 coefficients, such as mean and variance.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude from the model candidate 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 cost given local values for the business condition variables.<sup>3</sup> These predictions are econometric

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<sup>3</sup> Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Western Power. We might then predict the cost of Western in period  $t$  using the following model.

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

Here  $\hat{C}_{Western,t}$  denotes the predicted cost of the company,  $N_{Western,t}$  is the number of customers it serves, and  $W_{Western,t}$  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

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

benchmarks. Cost performance is measured by comparing a company's cost in year  $t$  to the cost projected for that year by the econometric model. The year in question can, in principle, be in the past or the future.

### 2.3.2 Index-Based Approaches to Benchmarking

The index-based approach to benchmarking is commonly employed by utilities in internal reviews of operating performance. Benchmarking indexes are also used in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost indexes.

An index is defined in one respected 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)".<sup>4</sup> In 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 group of companies represented in the sample is sometimes called a "peer" group.<sup>5</sup>

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 numerous consumer products. The weight for the inflation in the price of each product is its share of the value of all of the products considered.

To better appreciate the advantages of multidimensional indexes in utility benchmarking, recall from our discussion in Section 2.3 that multiple variables are often needed to accurately measure the workload of utilities. Suppose, by way of example, that we are benchmarking the O&M expenses of a VIEU like Public Service. It would be desirable in this case to consider the number of customers it serves as well as its sales volume. If we separately calculate the company's cost per customer and per megawatt hour of generation we could come up with two very different assessments depending, among other things, on a company's propensity to search for bargains in bulk power markets instead of self-generating all power requirements. A final reckoning of performance then

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<sup>4</sup> *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

<sup>5</sup> The term cohort comes from the Latin word for one of the ten divisions of a Roman legion.

requires a sensible weighting of assessments using the two metrics. This can be provided by a unit cost *index*<sup>6</sup>.

In cost benchmarking, it makes sense for the weights corresponding to each output variable in a unit cost index to reflect the relative importance of the individual output variables as cost drivers. The importance of each 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 of customers served. It is straightforward to estimate the required elasticities using econometric estimates of cost function parameters. We can, for example, use as the weight for each output measure its share in the sum of the estimated cost elasticities for the output variables.

Unit cost indexes by themselves do not control for all of 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 excluded business conditions are similar on balance to those facing the subject utility. The choice of the peer group is thus an important step in a unit cost benchmarking exercise. It can be difficult to find a peer group for an individual VIEU in which all companies face similar business conditions but the peer group averages are not dominated by the results for a handful of companies.

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<sup>6</sup> Summary input price indexes are also useful in cost benchmarking. We might, for example, want an index of the prices of O&M inputs. In the construction of input price indexes it is customary to use the corresponding cost shares to calculate weights. It can be shown that this approach to weighting best reflects the impact of input prices on cost.

### 3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

#### 3.1 Data

The primary source of the cost and quantity data used in our empirical research for Public Service 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.

Data were considered for inclusion in the sample from all major U.S. investor-owned electric utilities that filed the Form 1 electronically in 2008 and had substantial involvement in power production as well as power transmission, distribution, and customer care during the sample period. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from forty eight companies were used in the research. These companies are listed in Table 1. The sample period was 1995-2008. The resultant data set has 642 observations on each model variable.<sup>7</sup> This sample is large and varied enough to permit econometric identification of numerous O&M cost drivers and reasonably accurate estimation of their likely cost impact.

Other sources of data were also accessed in the research. Data on generation capacity originated in Form EIA – 860 ("Annual Electric Report") and a predecessor data source, Form EIA – 767 ("Steam Electric Plant Operation and Design Report"). Some data sources were used to measure input prices. These sources included Global Insight and the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. 2010 forecast data for Public Service were provided by the Company. These data are consistent with the Company's recent rate case filing.

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<sup>7</sup> Some observations for companies with data included in the sample were excluded due to data problems.

## **3.2 Definition of Variables**

### **3.2.1 Cost**

Cost figures play a key role in our research for Public Service. The base rate O&M expenses addressed in the featured benchmarking work were total electric O&M expenses less all reported expenses in the FERC Form 1 categories devoted to fuel, purchased power, transmission dispatching, transmission by others, regional market management, and employee pensions and benefits.<sup>8</sup> We routinely exclude pension and benefit expenses from our cost benchmarking work on the grounds that they are volatile, vary with accounting practices, and are to a considerable degree beyond the control of utility management. Expenses for transmission by others were excluded because they depend on a utility's power trade and the terms of transmission services provided by others are largely beyond utility control. Transmission dispatch and regional market expenses are excluded because these depend greatly on whether a utility operates under a regional transmission organization.

### **3.2.2 Output Measures**

Two output measures were utilized in both benchmarking approaches. One is the annual average number of customers served. The other is the total annual megawatt hours of net generation. An additional variable that varies with operating scale, generation capacity, is discussed further below.

### **3.2.3 Input Prices**

Cost theory 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 of base rate O&M inputs. In estimating the model we divide cost by this input price index. This is commonly done in econometric cost research because this simplifies model estimation and ensures that the relationship between cost and input prices that is predicted by economic theory holds.

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<sup>8</sup> 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 and volatile commodity-related costs are sometimes reported in this category.



The O&M input price index was constructed by PEG Research and is a weighted average of price indexes for labor and materials and services. The labor price component of our input price index was constructed by PEG Research personnel using BLS data. National Compensation Survey ("NCS") data for one recent year were used to construct average wage rates that correspond to each utility's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the level in the focus year for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from publicly available BLS data.

Prices for material and service ("M&S") O&M inputs are assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. They are escalated by a summary M&S input price index constructed by PEG Research from detailed Global Insight electric utility M&S indexes. The O&M input price for each utility is then constructed by combining the labor and non-labor prices using utility-specific cost share weights.

#### **3.2.4 Other Business Conditions**

Nine other business condition variables are included in the cost model. Four pertain to power generation activity. One is the total nameplate generation capacity owned by the company, measured in megawatts (MWs). Capacity is an important supplemental cost driver because the O&M of capacity is costly even when it is idle. Data on capacity were processed from FERC Form 1 data on individual power plants. 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 is the amount of generation capacity.

The model also contains variables that measure the share of generating capacity owned by each company that is coal-fired and the share that is not nuclear fueled<sup>9</sup>. These variables are designed to capture any tendency for O&M expenses to vary with the kind of

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<sup>9</sup> We sometimes use "not" variables in our studies to avoid situations where the variables have a value of zero for some utilities.

generating plant that companies own. The impact of these variables cannot be predicted in advance.

The fourth generation-related variable in the model is the percentage of total generating capacity that doesn't have 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 O&M expenses will be lower the lower is the percentage of generating capacity that is not scrubbed.

Four model variables address conditions that affect the cost of providing power delivery and customer care services. One of these measures the extent of system overheading. System overheading involves higher O&M expenses in most years because lines are more exposed to the challenges posed by local weather (e.g. high winds and ice storms), flora, and fauna<sup>10</sup>.

A second model variable related to delivery and customer care services is the number of customers per transmission line mile<sup>11</sup>. The source of our transmission line mile data is a directory that is currently entitled *Directory of Electric Power Producers and Distributors*. This is an annual publication of McGraw-Hill. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. We would expect that as the number of customers per transmission line mile --- sometimes called customer "density" --- increases, cost would decrease.

A third model variable related to delivery and customer care services is a measure of the demand side management ("DSM") work being done by each utility. Due to a lack of explicit itemization of DSM expenses on the FERC Form 1, these expenses cannot be removed from the costs subject to benchmarking. A control variable is therefore needed and we use for this purpose the share of total distribution, customer care, and sales expenses that is not classified as customer service and information ("CS&I"). This approach makes sense because DSM expenses are usually reported as a CS&I expense and loom large in these expenses when they are large. The variable is, effectively, a measure of the *lack* of DSM

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<sup>10</sup> Maintenance of underground delivery facilities occurs less frequently but can be quite costly.

<sup>11</sup> Due to data limitations the value of this variable is frozen at its 1999 value for all companies in the model's estimation.

work. Given this form, we would expect that the higher the value of the variable the lower cost would be.

The fourth model variable related to delivery and customer care services is the number of customers for which a utility provides gas service. Simultaneous provision of delivery and customer care services to gas and electric customers involves opportunities to share inputs that economists call economies of scope. We therefore expect electric O&M expenses to be lower the higher is the number of gas customers served.

The econometric model also contains a trend variable. This permits predicted cost to shift 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. Parameters for such variables typically have a negative sign in statistical cost research. The inclusion of this variable in the model means that our benchmark for 2010 includes an expectation of productivity growth.

### 3.3 Parameter Estimates

Estimation results for the cost model are reported in Table 2. Due to the chosen form of the cost function, the parameter estimates for the nine additional business conditions and for the "first order" terms of the output variables are elasticities of the cost of the sample mean firm with respect to the basic variable<sup>12</sup>. The table shades the results for these terms for reader convenience.

The table also reports the values of the asymptotic t-ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. 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 asymptotic t ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level was t value was about 1.7.

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<sup>12</sup> The first order terms are the terms that do not involve squared values of output variables or interactions between these variables. The "translog" form of the cost function is discussed in the Appendix.

The t-ratios were used in model specification. All the output quantities (which were translogged in model specification, as discussed further in the Appendix) were required to have first order terms with statistically significant and sensibly-signed parameter estimates. The other variables were also required to have statistically significant and sensibly-signed parameter estimates.

Examining the results in Table 2, it can be seen that all of the model parameter estimates are plausible as to sign and magnitude. At the sample mean, cost was found to be higher the higher were the values of all three scale-related variables. A 1% increase in the number of customers served was estimated to raise O&M expenses by 0.46%. A 1% hike in the generation volume was estimated to raise cost by 0.40%. A 1% increase in generation capacity is expected to raise cost by 0.05%. It follows that growth in the number of customers served has about the same cost impact as comparable growth in the two generation variables combined.

The parameter estimates for the additional business condition variables were also sensible.

- Cost was lower the greater was the percentage of capacity that wasn't nuclear.
- Cost was higher the greater was the percentage of capacity that was coal-fired.
- Cost was lower the greater was the percentage of capacity that wasn't scrubbed.
- Cost was lower the greater was the number of customers per transmission line mile.
- Cost was higher the greater was the extent of delivery system overhauling.
- Cost was lower the lower was the apparent amount of DSM work undertaken.
- The estimate of the trend variable parameter suggests a slight 0.2% annual downward shift in cost over time for reasons other than the trends in the business condition variables.

The table also reports the adjusted  $R^2$  statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.95, suggesting that the explanatory power of the model was high.

### 3.4 Business Conditions of Public Service

Public Service is a combined gas and electric utility with vertically integrated electric operations. Metropolitan Denver is the heart of its service territory. Service is also provided in corridors along the base of the northern Front Range, in the South Platte and San Luis Valleys, and in a swath of territory that runs across Colorado's midsection and includes Grand Junction.

The company generates a sizable percentage of the power that it sells but also buys substantial quantities. Most generation is coal-fired, but the company also operates a sizable fleet of gas-fired stations that includes combined cycle capacity. The Company owns and operates almost 4,300 miles of transmission line. There is no RTO in the region. The system makes sizable bulk power deliveries to other utilities.

The business conditions that drive the Company's O&M expenses will change substantially between 2008 and 2010. The Comanche 3 coal-fired generating station and two new gas-fired units at the Fort St. Vrain station will be fully operational. The share of coal fired capacity that has scrubbing facilities will increase markedly. DSM expenditures will also increase markedly, and these expenses will prospectively be expensed rather than amortized.

Table 3 compares the average values of the business conditions that Public Service forecasts for 2010 to the average values for the full sample in 2008. Values for Public Service are provided for 2008 as well as 2010. The last column of the table takes the ratio of the business conditions forecasted for Public Service in 2010 to the peer group norms.

It can be seen that the forecasted cost of Public Service in 2010 will be 1.19 times the sample mean in 2008. The number of customers served will, meanwhile, be 1.67 times the mean, while the net generation volume will be 1.04 times the mean and generation capacity was .84 times the mean.

Regarding input prices, the table shows that the O&M input prices faced by Public Service will be about 1.12 times the sample mean. This isn't surprising when it is considered that only a few of the companies in the sample have service concentrated in one of the nation's major metro areas. Turning next to the generation-related business

conditions, Public Service has no nuclear capacity but the share of its capacity that is coal-fired capacity will be well above the sample norm. The percentage of generation capacity that is not scrubbed will be well below the sample norm.

As for the other business condition variables, the number of customers per transmission line mile will be about 1.57 times the sample mean. This suggests that the company can reap some transmission cost savings from the concentration of its customers in metro Denver. The forecasted extent of system overheading is only 0.51 times the norm, and this creates opportunities for distribution O&M economies. Provision of service to gas customers affords opportunities for scope economies. On the other hand, the DSM indicator variable suggests that 2010 O&M expenses reflect unusually high DSM expenses.

### **3.5 Benchmarking Results**

#### **3.5.1 Econometric Results**

Table 4 presents the results of our econometric appraisal of Public Services's forecasted base rate O&M expenses for 2010. Excluding pensions, the Company's expenses were found to be more than 17% below the model's projection. A performance of this kind is ordinarily commensurate with a top quartile ranking in our research

#### **3.5.2 Unit Cost Results**

Table 5 benchmarks the proposed 2010 test year expenses using unit cost metrics. Comparisons are made to mean values for the full sample and the utilities in the Western Interconnection. Inspecting first the comparisons to the full sample, we see that Public Service's cost *per customer* is about 43% below the sample mean. Cost *per MWh generated* is 4% above the mean and cost *per MW of capacity* is about 23% above the mean. The disparity in these results is unsurprising given the fact that Public Service plans to continue purchasing large amounts of power in an effort to minimize the cost of power supply.

The unit cost index takes a weighted average of these results in order to produce a summary appraisal. We find that the proposed O&M expenses have a unit cost index value that is 16% below the full sample norm. The unit cost index for Public Services 2010 O&M expenses is 24% below the norm for the Western Interconnection.

### 3.6 Incentive Impact of Forward Test Years

In order to test the incentive impact of forward test years we considered the unit O&M expenses of the sampled utilities over the full 1995-2008 sample period. As in our benchmarking work, we considered three simple unit cost metrics, each of which involved a single dimension of operating scale. We also computed summary unit cost indexes that, effectively, take a weighted average of the trends for the simpler metrics. We considered how the unit cost trends differed for utilities operating under three kinds of test years: historical, partial, and forward. We defined a forward test year as one in which the last month of the test year was at least 12 months after the month of the rate case filing. We relied primarily on SNL for data on the filings.

Table 6 shows the kinds of test years used to regulate each of the utilities. It can be seen that 31 utilities operated under an historical test year, 3 operated under a partial test year, and 9 operated under forward test years. Some utilities could not be classified as operating under a particular test year regime.

Results of this exercise are reported in Table 7. It can be seen that using all three of the simple unit cost metrics and the unit cost index, the unit cost trends of the forward test year utilities were similar to --- and a little *slower* than --- those of the historic test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain unit cost that are generated by historic and future test years.

## APPENDIX

This section provides additional and more technical details of our empirical research.

### Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. Here is a simple example of a linear cost model.

$$C_{h,t} = a_0 + a_1 \cdot YN_{h,t} + a_2 \cdot W_{h,t} \quad [A1]$$

Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln YN_{h,t} + a_2 \cdot \ln W_{h,t} \quad [A2]$$

In the double log model the dependent variable and both business condition variables have been logged. 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 output quantity. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume.<sup>13</sup> This is restrictive, and may be inconsistent with the true form of the cost relationship that we are trying to model.

Here is an analogous model of translog form<sup>14</sup>

$$\begin{aligned} \ln C_{h,t} = & a_0 + a_1 \cdot \ln YN_{h,t} + a_2 \cdot \ln WL_{h,t} + a_3 \cdot \ln YN_{h,t} \cdot \ln YN_{h,t} \\ & + a_4 \cdot \ln WL_{h,t} \cdot \ln WL_{h,t} + a_5 \cdot \ln WL_{h,t} \cdot \ln YN_{h,t} \end{aligned} \quad [A3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as  $\ln YN_{h,t} \cdot \ln YN_{h,t}$  permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. The

<sup>13</sup> Cost elasticities are not constant in the linear model that is exemplified by equation [A1].

<sup>14</sup> 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.



elasticity of cost with respect to the output variable may, for example, be lower for a small utility than for a large utility that has exhausted its opportunities to realize incremental scale economies. Interaction terms like  $\ln WL_{h,t} \cdot \ln YN_{h,t}$  permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in output may depend on the price of labor in the service territory.

The translog form is an example of “flexible” functional form. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms such as the double log. As the number of variables subject to the translog treatment increases, the precision of a model’s cost prediction falls. It is therefore common to limit the number of variables in a cost model that are translogged. In this study, we have limited the translog treatment to the output variables of our model.

### **Estimation Procedure**

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions that are 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 in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Estimation procedures that address *several* of the error term issues that are routinely encountered in utility benchmarking are not readily available in commercial econometric software packages such as Gauss and Stata. They require, instead, the development of customized estimation programs. While the cost of developing sophisticated estimation procedures that are tailored for benchmarking applications is sizable, the incremental cost of applying them to different utilities is typically small once they have been developed.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG Research using the GAUSS statistical software program. Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators (MLE).<sup>15</sup> 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 Public Service. However, computation of model parameters and 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. This implies that the estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

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<sup>15</sup> See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

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Table 1

## SAMPLE OF UTILITIES USED FOR EMPIRICAL RESEARCH

Alabama Power	Minnesota Power
Appalachian Power	Mississippi Power
<b>Arizona Public Service</b>	Montana Dakota Utilities
<b>Avista</b>	<b>Nevada Power</b>
<b>Black Hills</b>	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	Otter Tail Power
Duke Energy	<b>Portland General Electric</b>
<b>El Paso Electric</b>	<b>Public Service Company of Colorado</b>
Empire District Electric	<b>Public Service Company of New Mexico</b>
Entergy Arkansas	Public Service Company of Oklahoma
Entergy Louisiana	<b>Pacificorp</b>
Florida Power & Light	<b>Puget Sound Energy</b>
Florida Power	<b>Sierra Pacific Power</b>
Georgia Power	South Carolina Electric & Gas
Gulf Power	Southern Indiana Gas & Electric
<b>Idaho Power</b>	Southwestern Electric Power
Indianapolis Power & Light	Southwestern Public Service
Kansas City Power & Light	Tampa Electric
Kentucky Power	<b>Tucson Electric Power</b>
Kentucky Utilities	Virginia Electric & Power
Louisville Gas & Electric	Western Resources

48 sampled utilities

**Boldface indicates Western Interconnect utilities**

Table 2

# Econometric Model of Non-Fuel O&M Expenses - Pensions Excluded

## VARIABLE KEY

N = Number of Customers  
VG = Net Generation Volume (MWh)  
KG = Total Generation Capacity (MW)  
NT = Customers per Transmission Line Mile  
S = % of Generation Capacity that is Not Scrubbed  
NUKE = % of Generation Capacity that is Not Nuclear  
DSM = % of Distribution that is Not Customer Service and Sales  
C = % of Generation Capacity that is Coal  
OH = % of T&D Plant Overhead  
NG = Number of Gas Customers  
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.463 <sup>1</sup>	16.25	0.000
NN	0.238	4.57	0.000
NVG	-0.243	-6.20	0.000
VG	0.393 <sup>1</sup>	12.08	0.000
VGVG	0.259	7.48	0.000
KG	0.053 <sup>1</sup>	1.96	0.050
NT	-0.036	-2.65	0.005
S	-0.072	-3.64	0.000
NUKE	-0.024	-18.50	0.000
DSM	-0.406	-10.08	0.000
C	0.074	6.88	0.000
OH	0.106	3.05	0.002
NG	-0.005	-3.23	0.001
Trend	-0.002	-1.69	0.092
Constant	14.890	685.10	0.000
Rbar-Squared	0.950		
Sample Period	1895-2008		
Number of Observations	642		

<sup>1</sup> Elasticity estimate used to develop output indexes discussed in Table 5. The elasticity weight for customers is .463/.914 = .507. The elasticity weight for generation volume is .398/.914 = .435. The elasticity weight for generation capacity is .053/.914 = 0.058. These weights sum up to 1.000.

Table 3

# Comparison of Public Service's Business Conditions To Full Sample Norms

Business Condition	Units	PSCo Values, 2008		PSCo Values, 2010		Difference between PSCo Values, 2008 & 2010		PSCo 2010 / Sample Mean 2008
		[A]		[B]		[B/A]		
Non-Fuel O&M Cost	Dollars	396,599,998		513,066,110		1.294	430,656,335	1.19
Price Index of Labor and Materials	Index Number	145.80		149.26		1.024	133.1	1.12
Number of Retail Customers	Count	1,358,033		1,364,464		1.005	815,175	1.67
Net Generation Volume	MWh	21,862,160		25,223,285		1.154	24,351,109	1.04
Total Generation Capacity	MW	4,037		4,799		1.189	5,700	0.84
Customers per Transmission Line Mile	Ratio	409.8		330.3		0.806	210.65	1.57
% of Generation that is Not Scrubbed	Percent	55.3%		50.0%		0.904	0.764	0.65
% of Generation that is Not Nuclear	Percent	100.0%		100.0%		1.000	0.938	1.07
% of Distribution that is Not Customer Service and Sales	Percent	75.9%		59.2%		0.780	0.872	0.68
% of Generation Capacity that is Coal	Percent	67.4%		58.0%		0.860	0.513	1.13
% of Transmission and Distribution Plant Overhead	Percent	38.8%		36.6%		0.942	0.714	0.51
Number of Gas Customers	Count	1,287,556		1,297,205		1.007	94,182	13.77

Table 4

**Econometric Comparison of Actual and  
Predicted O&M Cost for PSCo**

<u>Year</u>	<u>Difference (%)</u>
2010	-17.2%

Table 5

# How PSCo's 2010 Unit Cost Compares to Full Sample and Peer Group

	PSCo (2010)	Full Sample (2008)	Western Interconnection Utilities (2008)
Dollars per Customer	\$ 376	\$ 581	\$ 521
Dollars per MWh Generated	\$ 20.34	\$ 19.48	\$ 25.06
Dollars per MW Capacity	\$ 106,911	\$ 85,025	\$ 107,678
Summary Unit Cost Index	0.646	0.761	0.821

## How PSCO Compares<sup>1</sup>

Dollars per Customer	-43.4%	-32.6%
Dollars per MWh Generated	4.3%	-20.9%
Dollars per MW Capacity	22.9%	-0.7%
Summary Unit Cost Index	-16.4%	-24.0%

1: Percent differences calculated logarithmically



Table 6

## Test Years of Sampled Utilities

### Forward

Utility Name
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Minnesota Power
Mississippi Power
Northern States Power (MN)
Portland General Electric
Tampa Electric

### Partial

Utility Name
Columbus Southern Power
Dayton Power & Light
Ohio Power

### Historic

Utility Name
Appalachian Power
Arizona Public Service
Avista
Black Hills
Carolina Power & Light
Cleco Power
Duke Energy
El Paso Electric
Empire District Electric
Entergy Arkansas
Entergy Louisiana
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas & Electric
Nevada Power
Northern Indiana Public Service
Oklahoma Gas and Electric
Otter Tail Power
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of Oklahoma
Puget Sound Energy
South Carolina Electric & Gas
Southern Indiana Gas & Electric
Southwestern Electric Power
Southwestern Public Service
Tucson Electric Power
Virginia Electric & Power
Western Resources

### Excluded

Utility Name	Reason for Exclusion
Alabama Power	Test Year change during sample period
Idaho Power	Test Year change during sample period
Montana-Dakota Utilities	Varying test years amongst utility jurisdictions
Pacificorp	Varying test years amongst utility jurisdictions
Sierra Pacific Power	Varying test years amongst utility jurisdictions

Table 7

## Unit Cost Trends by Test Year 1995-2008

	Test Year Type			Western Interconnection Utilities
	Historic	Partial	Forward	All
Cost/Customer	2.2%	2.2%	1.9%	2.2%
Cost/Generation Volume	2.4%	2.3%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.0%	1.9%
Unit Cost Index	2.2%	2.3%	1.6%	2.2%
				1.9%
				2.3%
				1.7%
				2.1%

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