Statistical Research for Public Service Company of Colorado's Multiyear Electric Rate Plan

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STATISTICAL RESEARCH FOR PUBLIC SERVICE COMPANY OF COLORADO'S MULTIYEAR ELECTRIC RATE PLAN

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1. Introduction and Summary

1.1 Introduction

Public Service Company of Colorado ("Public Service" or "the Company"), a wholly owned regulated utility subsidiary of Xcel Energy, is proposing a multiyear rate plan ("MYP") for its electric services. The plan would set rates for four years from 2018 through 2021. The Company proposes an attrition relief mechanism ("ARM") of hybrid design for escalating its revenue requirement during the plan.

Revenue requirements of Colorado utilities can reflect future business conditions, but in past proceedings some parties have questioned the reasonableness and support for the Company's proposed forward test year revenue requirements. Parties have also claimed that the historical test years ("HTYs") traditionally used in Colorado better incentivize utility cost performance.

The Company's plan also includes revenue decoupling for residential and small commercial customers. Decoupling was recently approved for these customers by Colorado's Public Utilities Commission ("the Commission").[1] However, the Commission rejected an approach to decoupling that would have escalated the revenue requirement automatically for customer growth.

Pacific Economics Group Research LLC ("PEG") personnel have extensive experience in the fields of utility cost research and MYP design. We pioneered the use of rigorous statistical cost research in the regulation of North American energy utilities. Testimony-quality benchmarking and productivity studies are specialties. Mark Newton Lowry, President of PEG and senior author of this report, has testified numerous times on benchmarking, productivity, and MYP design.

Public Service has retained PEG to conduct four empirical research tasks that are relevant to its electric MYP filing. One is to benchmark the Company's proposed revenue requirements for non-fuel operation and maintenance ("O&M") expenses in each plan year. Another is to use index research to develop an escalator for the component of the Company's proposed revenue requirement which compensates it for these expenses. A third task is to demonstrate the need for

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[1] Public Utilities Commission of the State of Colorado, Proceeding No. 16A-0546E, Decision No. C17-0557, July 2017.

revenue requirement growth when a utility operates under revenue decoupling. A fourth is to use statistics to consider whether historical test years improve electric utility cost performance.

Following a brief summary of our research in Section 1.2 immediately below, Section 2 provides an introduction to statistical benchmarking. Section 3 discusses our electric service cost benchmarking work for Public Service. Section 4 discusses our work to develop an electric O&M revenue escalator. Section 5 presents empirical research supporting the need for escalation of the electric revenue requirement when companies operate under revenue decoupling. Section 6 considers the impact of historical test years on the cost of electric utilities. Some technical details of the research for this report are presented in the Appendix.

1.2 Summary of Research

We addressed the reasonableness of the Company's proposed revenue requirements for non-fuel electric O&M expenses during the MYP using statistical benchmarking.[2] Two well-established benchmarking methods were employed in the study: econometric modeling and unit cost indexing. Guided by economic theory, we developed a model of the impact various business conditions have on the non-fuel O&M expenses of vertically-integrated electric utilities ("VIEUs"). Parameters of the model which measure the impact of these business conditions on cost were estimated econometrically using historical data on VIEU operations. Models fitted with econometric parameter estimates and the business conditions Public Service expects to face during the MYP years generated revenue requirement benchmarks. We also used a simpler unit cost benchmarking method to evaluate these revenue requirements.

The benchmarking work employed a sample of good quality data on operations of 54 American VIEUs. Data used in the study were drawn from publicly available sources such as Federal Energy Regulatory Commission ("FERC") Form 1 reports. A Uniform System of Accounts has been in force for this form for decades. The sample period for the econometric work was 1996 to 2016. The sample is large and varied enough to permit development of sophisticated cost models in

[2] Some expenses were excluded from the study because they were unusually volatile, difficult to benchmark, substantially beyond utility control, and/or scheduled for separate tracker treatment under the proposed plan.

which several drivers of utility cost are identified. All estimates of the parameters of business condition variables were plausible and statistically significant.

The revenue requirements for non-fuel O&M expenses which Public Service proposes for the 2018-21 period were found to be about 23.6% below the benchmarks generated by our econometric benchmarking model on average. This score is commensurate with a first quartile (specifically number 4 of 54) performance.

As for the unit cost benchmarking, we compared the proposed real (i.e., inflation-adjusted) unit O&M revenue requirements of Public Service during the four plan years to the 2016 unit costs of 12 VIEU peers located chiefly in Great Plains and western states. The unit non-fuel O&M revenues proposed by Public Service were found to be 34.7% below the peer group norm on average. This score is commensurate with a top quartile (specifically number 2 of 13) performance. We conclude from our benchmarking work that the Company's proposed non-fuel O&M revenue requirements for the four MYP years reflect good levels of operating performance.

Indexes have been used in many approved MYPs to escalate utility rates or revenue requirements. In some plans these indexes reflect new information on business conditions which becomes available during a plan. In other plans these indexes are used with forecasts of business conditions to establish a fixed schedule of revenue escalation before the plan begins. Revenue requirement escalation indexes are also useful in rate cases with a single forward test year.

The index formula we developed to escalate revenue for non-fuel O&M expenses that Public Service does not propose to track is

$$\textit{growth } Revenue_{PSCO}^{O\&M} = \textit{growth Input Prices} - X + \textit{growth Scale}_{PSCO}.$$

Here *Scale* is an index of growth in the scale of the Company's electric operations. X is the 0.50% long run trend in the non-fuel O&M productivity of the sampled VIEUs. Using this formula and forecasts of O&M input price inflation and growth in the Company's scale, the indicated escalation in the O&M revenue is 2.11%.

During the MYP years, Public Service proposes revenue requirements for non-fuel O&M expenses not slated for tracking which reflect its forecast of the cost of advanced grid and intelligence security ("AGIS"). The salary and wage portion of its revenue requirement for other non-fuel O&M expenses are escalated by 3% to account for expected wage increases in 2017 and then escalated by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses is frozen.

The difference between the forecasted average annual growth in our O&M revenue escalator in the five years from 2016 to 2021 and the Company's proposed 1.77% growth over the same years in its non-fuel O&M revenue requirement not slated for tracker treatment is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 0.34%. Approved stretch factors in indexed ARMs of North American energy utilities typically range between 0 and 0.60% today. Stretch factors in the neighborhood of 0.3% are typically reserved today for average cost performers, whereas the Company is a demonstrably *good* non-fuel O&M cost performer.

The Commission recently rejected a feature of the Company's revenue decoupling proposal that would gradually escalate its revenue requirements for services subject to decoupling to reflect growth in the number of customers served. Customer growth is a good proxy for overall growth in the operating scale of an electric utility. Our research shows that the non-fuel revenue requirements of VIEUs typically grow at a pace that well exceeds customer growth.

To test the effect that using historical test years in rate cases have on cost management, we developed an econometric model of the growth in the non-fuel electric O&M expenses of VIEUs. We found no tendency for O&M cost to grow more slowly for utilities that operate in historical test year jurisdictions. We reached similar conclusions in previous studies we filed on this topic in Public Service proceedings.

2. AN INTRODUCTION TO BENCHMARKING

In this Section of the report we provide a non-technical introduction to cost benchmarking. The two benchmarking methods used in the study are explained. Details of our benchmarking work for Public Service are discussed in Section 3 and 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 involves one or more activity measures. These are sometimes called performance metrics or indicators. 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:

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

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. In utility cost benchmarking, data on the costs of utilities can be used to establish benchmarks. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard for utilities is the average performance of sampled utilities. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process for choosing athletes for 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. Values for these metrics which Hall of Fame members like Denver Broncos star John Elway have achieved are far superior to league norms.

2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface isn't very informative since runner speed is influenced by the slope of the surface. In comparing costs that utilities incur, it is similarly recognized that differences in their costs depend in part on differences in external business conditions they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves given the business conditions it faces. Benchmarks should therefore reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to business conditions in its service territory. When the focus of benchmarking is non-fuel O&M expenses, theory reveals that the relevant business conditions include the prices of O&M inputs, the scale of the company's operations, and the quantities of capital inputs. Miscellaneous other business conditions may also drive cost.

The existence of capital input variables in O&M cost functions means that appraising the efficiency of a utility in using O&M inputs requires consideration of the kinds and quantities of capital inputs that it uses. This result is important for several reasons. It is generally more costly to operate and maintain capacity the more of it there is. A utility that has older facilities nearing replacement age will tend to spend more on maintenance than a utility with newer facilities.

Regardless of the particular category of cost that is benchmarked, economic theory allows for the existence of multiple scale variables in cost functions. For example, the cost of a vertically-integrated electric utility depends on the number of customers it serves (as it provides distribution and customer care services) as well as on its generation volume.

2.3 Benchmarking Methods

In this section of our report we discuss the two benchmarking methods we used in this study. 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 results of a 100-meter sprinter racing uphill to a runner racing on a level course doesn't tell us much about the relative performance of the athletes. Statistics can aid appraisal of their performances. For example, we could develop a mathematical model in which time in the 100-meter dash is a function of conditions like wind speed and surface gradient. The parameters of the model which correspond to each condition would quantify their typical impact on run times. We could then use samples of times turned in by runners under varying conditions to estimate model parameters. The resultant "run-time" model could then be used to predict the typical performance of runners given the track conditions that they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data.[3] Parameters of a utility cost function can be estimated using historical data on costs incurred by a group of utilities and 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.

Basic Assumptions

Econometric research involves certain critical assumptions. One is that the value of an economic variable (called the dependent or left-hand side variable) is a function of certain other variables (called explanatory or right-hand side variables) and an error term. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the value of the dependent variable. 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. This term is 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.

[3] Estimation of model parameters is sometimes called regression.

Reasons for errors include mismeasurement of cost and external business conditions, exclusion from the model of relevant business conditions, and failure of the model to capture the form of the functional relationship between the economic variables. It is customary to assume that error terms in econometric models are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for appraising the importance of explanatory variables in cost models. Tests can be constructed for the hypothesis that the parameter for an included business condition equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates is called an econometric cost model. We can use such models to predict a company's costs given local values for the business condition variables.[4] 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 by the econometric model. Cost predictions can be made for historical or future years. Predictions of cost in future years can be used to benchmark forecasts or proposed revenue requirements for these costs.

Accuracy of Benchmarking Results

Statistical theory provides useful guidance regarding the accuracy of econometric benchmarks as predictors of the true benchmark. One important result is that a model can yield

[4] 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 simple model.

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

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $V_{Western,t}$ is its generation volume. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula like

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

where ln is the natural logarithm of the ratio in the parentheses.

biased predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to consider in model development numerous business conditions which are believed to be relevant and for which good data are available at reasonable cost.

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

- the model successfully explains the variation in the historical cost 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;
- business conditions of sampled utilities are varied; and
- business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric cost 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. It follows that it will generally be preferable to use *panel* data in the research, encompassing information from multiple utilities over time, when these are available.

2.3.2 Benchmarking Indexes

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. 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)."[5] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances if there are large differences in the cost drivers they face. In index-based cost benchmarking, it is therefore common to use as performance metrics the ratios of their cost to one or more important cost drivers. Differences in the operating scale of utilities are typically the greatest source of differences in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

$$\textit{Unit Cost} = \textit{Cost}/\textit{Scale}. \qquad [1]$$

Each index compares the value of the metric to the average for a peer group.[6] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in 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

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

[6] A unit cost index for Western Power, for instance, would have the general form

$$\textit{Unit Cost}_t^{\textit{Western}} = \frac{\textit{Cost}_t^{\textit{Western}}/\textit{Cost}_t^{\textit{Peers}}}{\textit{Scale}_t^{\textit{Western}}/\textit{Scale}_t^{\textit{Peers}}}.$$

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.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices utilities face. The formula for real (price-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\,Input\ Prices}{Scale} \quad . \qquad [2]$$

A productivity index ("Productivity") is the ratio of a scale index to an input quantity index ("Inputs").

$$Productivity = \frac{Scale}{Inputs} \qquad [3]$$

It can be shown that cost is the product of properly-designed input price and quantity indexes:

Cost = Input Prices • Input Quantities. [4]

Relations [2] - [4] imply that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity. \qquad [5]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index. Low unit cost coincides with high productivity. We discuss productivity indexes further in Section 4.2 below.

Multidimensional Scale Indexes

Indexes can be designed to summarize results of multiple comparisons. Such summaries involve averages of the comparisons. Consumer price indexes are familiar examples. These commonly summarize inflation (year-to-year comparisons) in prices of a market basket of goods and services. The weight for the price of each product is its share of the value of all of the products in the basket. If households typically spend $300 a week on food and $30 on coffee, for instance, 4% growth in the price of food would have a much bigger impact on the CPI than the same growth in the price of coffee.

The scale index of a firm or industry summarizes its scale of operation. Growth in each scale dimension that is itemized is measured by a subindex. One possible objective of scale research is to measure the impact of scale on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. A productivity index calculated using a cost-based scale index may fairly be described as a "cost efficiency index."

To better appreciate advantages of multi-dimensional indexes in utility cost benchmarking, recall from our discussion above that the operating scale of a utility is sometimes most accurately measured using several scale variables. These variables can have different importance even if all are worth considering. Multi-dimensional scale indexes are particularly useful in measuring the performance of *vertically integrated* electric utilities because they provide unusually varied services.

The cost impact of a scale 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 elasticities like these using econometric estimates of cost model parameters. The weight for each variable in the scale index for a cost efficiency study can then be its share in the sum of the estimated cost elasticities of the model's scale variables.[7]

[7] For an early discussion of elasticity-weighted scale indexes see Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "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) pages 179-218.

3. Empirical Research for Public Service

3.1 Data

Cost benchmarking of US electric utilities is facilitated by the detailed, standardized data on their operations which the federal government has gathered for decades from dozens of companies. The primary source of the cost data used in this study was the FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts.[8] Data on generation capacity were drawn from Form EIA – 860 ("Annual Electric Generator Report") and a predecessor source, Form EIA – 767 ("Steam Electric Plant Operation and Design Report"). Most data on the number of customers served originated in Form EIA 861 ("Annual Electric Power Industry Report"). PEG gathered the data from all these sources which were used in this study.

Data on historical prices of material and service ("M&S") inputs were drawn from the Global Insight *Power Planner*. Data on historical salaries and wages were drawn from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. We forecasted the non-fuel O&M input price inflation of Public Service using industry forecasts from the latest edition of *Power Planner*. Forecasts of other business conditions faced by Public Service were provided by the Company.

Data were considered for inclusion in our sample from all major investor-owned U.S. electric utilities that filed the Form 1 during the sample period and had substantial involvement in power production, transmission, and distribution 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 54 companies were used in the research. The sampled companies are listed in Table 1. The companies in the Company's unit cost peer group are identified in the table.

The sample period for the econometric cost study was 1996-2016. The resultant dataset had 1,134 observations. This sample is large and varied enough to permit development of a credible econometric model of O&M expenses.

[8] Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Table 1
Sample of VIEUs Used in the Empirical Research

Alabama Power	Kentucky Utilities
ALLETE (Minnesota Power)	Louisville Gas and Electric
Ameren Missouri (Union Electric)	MDU Resources Group
Appalachian Power	MidAmerican Energy*
Arizona Public Service*	Mississippi Power
Avista*	Monongahela Power
Black Hills Power	Nevada Power*
Cleco Power	Northern Indiana Public Service
Dayton Power and Light	Northern States Power Company - MN*
Duke Energy Carolinas	Oklahoma Gas and Electric*
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	Pacific Gas and Electric
Duke Energy Progress	PacifiCorp
El Paso Electric*	Portland General Electric*
Empire District Electric	Public Service Company of Colorado
Entergy Arkansas	Public Service Company of New Mexico
Entergy Mississippi	Public Service Company of Oklahoma
Entergy New Orleans	Puget Sound Energy*
Florida Power & Light	Sierra Pacific Power*
Georgia Power	South Carolina Electric & Gas
Gulf Power	Southern Indiana Gas and Electric
Idaho Power	Southwestern Electric Power
Indiana Michigan Power	Southwestern Public Service
Indianapolis Power & Light	Tampa Electric*
Kansas City Power & Light	Tucson Electric Power*
Kansas Gas and Electric	Virginia Electric and Power
Kentucky Power	Westar Energy

Sample Size = 54 VIEUs

*Indicates a company in the unit cost peer group

3.2 Definition of Variables

3.2.1 Calculating O&M Expenses

The cost addressed in our benchmarking work was total electric O&M expenses less expenses for generation fuel, purchased power, customer service and information, pensions and benefits, and franchise fees.[9] We also excluded certain transmission expenses.

We routinely exclude expenses for fuel, purchased power, and pensions and benefits from our cost benchmarking studies on the grounds that they are large, volatile, and---to a considerable degree---beyond the control of utility management. In addition, Public Service proposes to track energy and pension expenses in the MYP. Customer service and information expenses were excluded because these vary greatly with the extent of demand-side management ("DSM") programs. Utility DSM expenses are not itemized on FERC Form 1 for easy removal and would be tracked in the Company's proposed MYP. Franchise fees also vary greatly between utilities and are substantially beyond their control.

As for transmission expenses, the cost of transmission services purchased from other entities varies widely between utilities and is itemized for easy removal. Some sampled utilities are members of regional transmission organizations ("RTOs") that perform some transmission services (e.g., dispatching and planning) for members that other utilities do themselves. RTOs may additionally charge utilities for their management of regional bulk power markets. It is undesirable to include these expenses in a benchmarking study.

Note also that utilities make purchases and sales in bulk power markets. RTOs charge members for transportation of this power under the terms of RTO tariffs. Member utilities also provide RTOs with transmission services that include making their infrastructure available for use. RTO invoices to member utilities for transmission services may thus include some of the cost of the services these utilities provide. These invoiced sums have sometimes been reported by utilities as O&M expenses, leading to inflated expenses that are offset elsewhere on Form 1 by reported transmission revenues.

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

We have accordingly excluded from the cost we studied certain transmission and RTO expenses. The cost categories not considered included transmission of electricity by others (FERC account 565), miscellaneous transmission expenses (FERC account 566), regional market expenses (FERC accounts 575 and 576), and new transmission accounts created at the same time as accounts 575 and 576 (561.1–561.8 and 569.1-569.4).

3.2.2 Scale Variables

Two “classic” measures of utility scale were utilized in our benchmarking work: the annual average number of customers served and the total annual megawatt hours of net generation. Simply put, the greater is the number of customers a utility serves and the generation volume it achieves, the higher is its cost. The parameters of both of these variables are therefore expected to have positive signs. A measure of generation capacity that was used in the model is also scale-related and is discussed in Section 3.2.4 below.

3.2.3 Input Prices

Cost theory also suggests that the prices paid for inputs are relevant business condition variables. We therefore included in the model an index of the prices of non-fuel O&M electric utility inputs. In estimating the model we divide cost by this input price index. This is commonly done in econometric cost research because it simplifies model estimation and ensures that the relationship between cost and input prices predicted by economic theory holds.[10]

The O&M input price index was constructed by PEG and is a weighted average of price subindexes for labor and M&S inputs. Occupational Employment Statistics (“OES”) survey data for a 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 OES pay level for each job category using weights that correspond to the electric utility industry. Values for other years were calculated by adjusting the level in the focus year for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were also constructed from BLS data.

[10] Theory predicts that a 1% increase in the prices of all inputs will raise cost by 1% if all other business conditions are unchanged.

Prices for M&S inputs were assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. We use our labor price index to effect this levelization in the same focus year. The M&S price is then escalated by a summary M&S input price index constructed by PEG from detailed Global Insight electric utility M&S indexes and company-specific, time-varying cost share weights. The O&M input price for each utility is constructed by combining the labor and M&S price subindexes using company-specific, time-varying cost share weights. The cost shares were calculated from FERC Form 1 data.

3.2.4 Other Business Conditions

Eight other business condition variables were included in the cost model. Five pertain to power generation. One is the total nameplate generation capacity owned by the utility, measured in megawatts ("MWs"). Capacity is an important cost driver because ownership of capacity involves O&M expenses even when it is idle. Our research team aggregated the nameplate capacity of each sampled utility's 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 parameter for this variable should therefore have a positive sign.

The model also contains variables that measure the share of generating capacity owned by each utility that is fired by coal or heavy fuel oil, and the share that is nuclear-fueled. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating capacity that companies own. While the cost impact of these variables cannot be predicted theoretically, our experience in the industry suggests positive signs for their parameters.

The fourth generation-related variable in the model is the percentage of total generating capacity that has scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. The propensity to scrub depends in part on ownership of coal- and oil-fired generation, but companies also vary in the percentage of emissions from such capacity that they scrub. We expect that O&M expenses will be higher the higher is the percentage of generating capacity with scrubbers.

The fifth generation-related variable is the average age of generation capacity. Generation O&M tends to rise as the capacity ages. The parameter of this variable should therefore have a positive sign.

Three model variables address business conditions that affect the cost of power delivery and/or customer care. One of these measures the extent of delivery system overheading. This is measured as the share of overhead plant in the gross value of transmission and distribution ("T&D") conductor, device, and structure (pole, tower, and conduit) plant. System overheading involves higher O&M expenses in most years because facilities are more exposed to the challenges posed by local weather (e.g., high winds and ice storms), flora, and fauna.[11] The sign of this variable's parameter should therefore be positive.

A second model variable related to delivery is the mileage of high voltage ("HV") transmission lines per retail customer in 2012. Lines with a kV rating of 100 or greater are counted in this metric.[12] The source of our transmission line mile data is the FERC Form 1. We would expect that cost would be greater the greater is the value of this variable.

The third model variable related to delivery and customer care services is the share of total gas and electric retail customers that are electric. Simultaneous provision of delivery and customer care services to gas and electric customers provides opportunities to share O&M inputs, which economists call economies of scope. We expect electric O&M expenses to be higher the higher is the value of this variable since a higher value means fewer scope economies.

The econometric model also contains a trend variable. This variable 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 often have a negative sign in statistical cost research. The inclusion of this variable in the model means that our econometric benchmarks for future years include an expectation regarding the residual cost trend.

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[11] Maintenance of underground delivery facilities can be quite costly but occurs less frequently.

[12] Subtransmission (e.g., 69kV) lines are excluded from this variable because some companies classify these lines as distribution facilities and good data on distribution lines were not available for all sampled companies.

3.3 Econometric Parameter Estimates

Estimation results for the cost model are reported in Table 2. This table also reports values of the asymptotic t-ratios that correspond to each parameter estimate. These were used in model development. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires 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 about 1.65.

Table 2
Econometric Model of Electric O&M Cost

N = Number of Retail Customers
CAPTOT = Total Generating Capacity
GNET = Net Generation Volume
AGETOT= Average Age of Generation Plant
PCTDIRT= Percentage of Generation Capacity that is Coal or Heavy Fuel Oil
PCTNUC= Percentage of Generation Capacity that is Nuclear
PCTSCR= Percentage of Generation Capacity that is Scrubbed
PCTELEC= Percentage of Retail Customers who are Electric
TXMIPERCUST= Line Miles per Retail Customers in 2012
PCTPOTD= Percentage of Line Plant that is Overhead
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.546	24.558	0.0000	**PCTNUC**	0.275	21.575	0.000
CAPTOT	0.183	7.446	0.0000	**PCTSCR**	0.066	4.369	0.000
GNET	0.122	6.119	0.0000	**PCTELEC**	0.070	2.178	0.030
AGETOT	0.128	4.119	0.0000	**TXMIPERCUST**	0.050	3.516	0.000
PCTDIRT	0.186	6.329	0.0000	**PCTPOTD**	0.131	3.290	0.001
				Trend	-0.005	-4.487	0.000
				Constant	19.616	741.485	0.000

Rbar-Squared	0.955
Sample Period	1996-2016
Number of Observations	1134

Examining the results in Table 2, it can be seen that all of the estimates of business condition parameters are statistically significant and plausible as to sign and magnitude. Non-fuel

O&M expenses were found to be higher the higher were the values of all three scale-related variables. The number of customers served had by far the highest parameter estimate of the three scale variables considered.

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

- Expenses were higher the higher was generation capacity age.
- Expenses were higher the greater was the share of total generation capacity fired by coal or heavy fuel oil.
- Expenses were higher the greater was the share of nuclear-fueled capacity.
- Expenses were higher the greater was the share of generation capacity scrubbed.
- Expenses were higher the greater was the number of electric customers served relative to gas customers.
- Expenses were higher the greater was the share of delivery plant overhead.Expenses were higher the greater was the mileage of transmission lines per customer in 2012.
- The estimate of the trend variable parameter suggests a 0.5% annual downward shift in cost over time for reasons other than the trends in the business condition variables. This shift is reflected in our benchmarks for Public Service.

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 0.955, 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. Electric service is also provided in other areas of Colorado which include the northern Front Range (e.g., Greeley), the Arkansas and San Luis Valleys (e.g., Salida and Alamosa), and parts of central and western Colorado (e.g., Grand Junction).

The Company buys a sizable percentage of the power that it sells but also generates large quantities. Extensive coal-fired generation capacity is a legacy of the proximity of the Company's loads to fields of low-cost coal. A high percentage of coal-fired capacity is scrubbed. Public Service also operates growing fleets of gas-fired and wind-powered capacity. In addition, the Company operates an extensive high voltage transmission system to access power supplies and deliver power to widely scattered regions.

Table 3 compares the values we use for the cost and business condition variables of Public Service in 2018 to the mean values for the full sample in 2016. The last column of the table takes the ratio of the business conditions for Public Service to the sample means.

It can be seen that the proposed non-fuel O&M revenue of Public Service in 2018 is expected to be 0.84 times the sample mean for 2016. In other words, the proposed cost is expected to be about 16% below the mean. The number of customers served would, meanwhile, be 1.62 times the mean, while the Company's net generation volume would be 0.95 times the mean, generation capacity would be 1.01 times the mean, and transmission line miles per customer would be 0.65 times the mean.

Table 3
Comparison of Public Service's Business Conditions in 2018 to Full Sample Norms

Business Condition	Units	Public Service Values, 2018 [A]	Sample Mean, 2016 [B]	2018 Public Service Values / 2016 Sample Mean [A/B]
Non-Energy O&M Expenses (2016 Dollars)	Dollars	429,341,953	514,083,143	0.84
Number of Retail Customers	Count	1,475,083	911,357	1.62
Total Generating Capacity	MW	6,230	6,154	1.01
Net Generation Volume	MWh	22,109,512	23,156,755	0.95
Average Age of Generation Plant	Years	26.24	31.57	0.83
Percentage of Generation Capacity that is Coal or Heavy Fuel Oil	Percent	0.45	0.42	1.06
Percentage of Generation Capacity that is Nuclear	Percent	0.00	0.07	0.00
Percentage of Generation Capacity Scrubbed	Percent	0.45	0.36	1.27
Percent of Total Customers that are Electric	Percent	0.51	0.89	0.57
Miles of Transmission Line Miles per Customer in 2012	Count	0.0029	0.0045	0.65
Percentage of Line Plant that is Overhead	Percent	0.40	0.73	0.55
Price Index for O&M Inputs	2016 Dollars	1.12	1.00	1.12

Public Service has no nuclear capacity but the share of its capacity that is coal- or oil-fired would be 1.06 times the sample mean. The percentage of capacity that is scrubbed would be 1.27 times the sample mean. Generation age would be 0.83 times the mean, suggesting that the Company's fleet is relatively young.

As for the other business condition variables, delivery system overheading would be only 0.55 times the mean. This creates opportunities for delivery O&M economies. Provision of service to gas customers affords the Company opportunities for scope economies in distribution and customer care. The 2018 O&M input prices faced by Public Service would be about 1.12 times the mean for 2016.

3.5 Benchmarking Work

We benchmarked the Company's proposed revenue requirements for non-fuel O&M expenses during the years of the MYP using econometric and indexing methods. In these calculations, we exclude the expected generation volume, capacity, and O&M expenses for the Rush Creek project because the Company proposes to track these expenses.

The Company's proposed revenue requirements for non-fuel O&M expenses would average 1.77% annual growth between the 2016 historical test year and 2021. These revenue requirements reflect the Company's forecast of the cost for AGIS. The salary and wage portion of its revenue requirement for other non-fuel O&M expenses would grow by 3% in the 2016 test year to reflect expected 2017 wage increases and by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses would be frozen.

3.5.1 Econometric Models

We created econometric benchmarks for the non-fuel O&M expenses of Public Service for each year of the 1996-2021 period. These benchmarks were based on the econometric model parameter estimates in Table 2 and values for the business condition variables which are appropriate for Public Service. For the 2017 to 2021 period most values for business condition variables were forecasted. However, the values for transmission miles/customer and the overhead variable were drawn from a recent historical year. Table 4 shows results of our non-fuel O&M benchmarking using the econometric models. The Company's proposed non-fuel O&M revenue requirements during the 2018-2021 period were found to be about 23.6% below the projections of our O&M cost benchmarking model on average. This score is commensurate with a top quartile (specifically 4 of 54) ranking.

Table 4
Year by Year PSCO Econometric Cost Benchmarking Results
[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark % Difference
1996	-33.3%
1997	-35.3%
1998	-37.7%
1999	-31.6%
2000	-34.3%
2001	-19.5%
2002	-24.3%
2003	-18.2%
2004	-25.3%
2005	-24.7%
2006	-24.2%
2007	-22.4%
2008	-27.9%
2009	-25.6%
2010	-15.5%
2011	-14.9%
2012	-23.8%
2013	-15.3%
2014	-17.9%
2015	-22.4%
2016	-22.1%
2017	-26.0%
2018	-26.1%
2019	-22.6%
2020	-22.2%
2021	-23.3%
Average 2018-2021	**-23.6%**

[1] Formula for benchmark comparison is $\ln(Cost^{PSCO}/Cost^{Bench})$.

3.5.2 Unit Cost Indexes

Table 5 shows the results of benchmarking the proposed 2018-2021 revenue requirements using real unit cost indexes. These indexes featured multidimensional scale indexes with cost elasticity weights. Our econometric research discussed in Section 3.3 shows that the number of customers served, generation capacity, and generation volume are useful scale variables for such indexes. Using the econometric parameter estimates for these variables, the cost elasticity weights for customers and generation capacity and volume in this index were set at 64%, 22%, and 14% respectively.

Table 5
How PSCO's Proposed Unit Electric Non-Fuel O&M Revenue Requirements Compare to the Unit Costs of Peers[1]

	Public Service 2018-2021 Average [A]	Peers 2016 [B]	Comparing Results Ratio [A/B]	Percentage Difference [(A/B)-1]
O&M Cost	429,408,402	394,252,217	1.089	8.9%
Number of Customers	1,496,712	782,795	1.912	91.2%
Total Generation Capacity[2]	6,086	4,990	1.220	22.0%
Net Generation Volume[2]	21,121,412	17,050,340	1.239	23.9%
Summary Scale Index[3]			1.667	66.7%
Dollars per Customer	286.9	503.6	0.570	-43.0%
Dollars per MW	70,555.8	79,014.7	0.893	-10.7%
Dollars per MWh Generated	20.3	23.1	0.879	-12.1%
Summary Unit Cost Index	**0.65**	**1.00**	**0.653**	**-34.7%**

[1] The peers are: Arizona Public Service, Avista, El Paso Electric, MidAmerican Energy, Nevada Power, Northern States Power-Minnesota, Oklahoma Gas & Electric, Portland General Electric, Puget Sound Energy, Sierra Pacific Power, Tampa Electric, and Tucson Electric Power.

[2] Rush Creek capacity and volumes are excluded from these totals.

[3] Scale index for O&M expenses constructed from the scale subindexes and cost elasticity weights based on Table 2 econometric estimates using the formula scale = 0.64* customers + 0.22* capacity + 0.14* net generation.

Comparisons are made to mean values for the peer group in 2016. It can be seen that the Company's proposed real non-fuel O&M revenue was about 35% below the peer group mean on average over the four-year period. This score is commensurate with a first quartile (specifically a number 2 of 13 ranking).

4. Designing an O&M Revenue Escalator

4.1 Revenue Cap Indexes

Index research provides the basis for revenue requirement escalators that can be used in MYPs and forward test year rate cases. The following result of cost theory is a useful starting point:

growth Cost = growth Input Prices – growth Productivity + growth Scale. [6]

The growth rate of cost is the difference between growth in input price and productivity indexes plus growth in a scale index.

This result provides the rationale for a revenue requirement escalator of the following general form:

growth Revenue = growth Input Prices – X + growth Scale [7a]

where

X = trend Productivity + Stretch. [7b]

Here *X*, the "X factor," is calibrated to reflect a base productivity growth target. This is typically the average historical trend in the productivity indexes of a utility peer group. A "stretch factor" is often added to the escalation formula to slow revenue requirement growth in a manner that shares with customers financial benefits of any productivity growth in excess of the peer group norm which is expected during the MYP. The stretch factor is often informed by statistical benchmarking evidence because an inefficient utility can more easily cut costs.

4.2 More on Productivity Indexes

4.2.1 The Basic Idea

The growth trend of a productivity index is the difference between the trends in a scale index and an input quantity index.

trend Productivity = trend Scale – trend Inputs. [8]

It can be shown that the input quantity trend can be measured as the difference between the trends in cost and an input price index.

trend Inputs = trend Cost - trend Input Prices. [9]

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input quantity index. Productivity can be volatile but has historically tended to grow over time.

The volatility of O&M productivity is affected by external events (e.g., severe storms) and uneven timing of some routine expenses. The volatility of productivity growth tends to be greater for individual companies than the average growth for a group of companies.

The scope of a productivity index depends on the array of inputs considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. An O&M productivity index measures productivity in the use of various O&M inputs.

$$\textit{trend Productivity}^{O\&M} = \textit{trend Scale} - \textit{trend Inputs}^{O\&M}. \qquad [10]$$

4.2.2 Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse.[13] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies can be available in the longer run if cost tends to grow more slowly than scale. A company's potential to achieve incremental scale economies depends on growth in its scale.

A third important source of productivity growth is change in X-inefficiency. X-inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when X-inefficiency diminishes (increases). The lower a company's current efficiency level, the greater is the potential for productivity growth from a change in inefficiency.

Productivity growth is also affected by changes in the miscellaneous external business conditions, other than input price and scale growth, which affect cost. A good example for an electric utility is the share of distribution lines that are undergrounded. An increase in the share of facilities that are undergrounded will tend to accelerate O&M productivity growth since less maintenance is needed. O&M productivity growth also tends to be slower to the extent that a Company's infrastructure is aging.

[13] For a seminal discussion of sources of productivity growth see Denny, Fuss and Waverman, *op. cit.*

4.3 O&M Productivity Trend of VIEUs

Growth in non-fuel O&M productivity was calculated for each VIEU in our sample as the difference between the growth rates of the utility's scale index and O&M input quantity index. The growth in each scale index was an elasticity-weighted average of the growth in three scale variables: generation volume and capacity and the number of retail customers served. O&M input quantity growth was measured as the difference between growth in applicable non-fuel O&M expenses and growth in the non-fuel O&M input price index that we used in the econometric work.

The full sample period for which productivity trends were calculated was 1997-2016. In other words, 1997 was the earliest year for growth rate calculations.

Table 6 presents results of our O&M productivity research for our full 54-company sample. Over the full 1997-2016 sample period, the average annual growth rate in the O&M productivity of all sampled utilities was 0.50 percent.[14] Growth in operating scale averaged 1.06 percent annually, while O&M input quantity growth averaged 0.56 percent.[15]

4.4 Indicated O&M Revenue Escalation for Public Service

Table 7 shows the construction of the non-fuel O&M revenue escalator we developed using formula [7a], the 0.50% O&M productivity growth trend, and forecasts of input price inflation and the Company's customer growth. No stretch factor is used in the Table 7 calculations since we are using the revenue cap index to calculate an implicit stretch factor. From 2016 to 2021, the non-fuel O&M input price index we used in the benchmarking work is forecasted to average 2.30% growth.[16] Public Service forecasts the number of its electric customers and generation capacity and volume to average 1.03%, -0.63%, and -1.48% annual growth, respectively. The expected decline in generation volume and capacity reflect the Company's disposition of the Valmont and Cherokee units. Rush Creek generation volumes and capacity are not considered because the Company proposes to track the cost of this project. Given, additionally, the 0.50% non-fuel O&M productivity

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[14] This result is in line with the -.005 value of the trend variable parameter estimate in the econometric model.

[15] Over the more recent 2006-2016 period, the average annual growth rate in the non-fuel O&M productivity of all sampled utilities was a little slower, averaging 0.39 percent.

[16] This forecast makes use of forecasts of price subindexes from Global Insight.

trend of sampled VIEUs, it can be seen that our O&M revenue escalator would average 2.11% annual growth.

Table 6
Non-Fuel-O&M Productivity Results For Sampled Utilities

(Growth Rates)[1]

Year	Scale Index	O&M Input Quantity Index	O&M Productivity Index
1997	1.88%	1.21%	0.68%
1998	1.96%	1.46%	0.50%
1999	0.99%	0.74%	0.26%
2000	1.25%	2.71%	-1.46%
2001	0.70%	0.63%	0.07%
2002	1.15%	-0.08%	1.23%
2003	1.63%	-1.46%	3.08%
2004	1.45%	1.20%	0.24%
2005	1.26%	0.06%	1.20%
2006	0.90%	0.33%	0.57%
2007	2.29%	3.37%	-1.08%
2008	0.83%	-1.35%	2.18%
2009	0.02%	-0.55%	0.57%
2010	1.73%	4.77%	-3.04%
2011	0.32%	-3.06%	3.38%
2012	-0.14%	-1.86%	1.72%
2013	1.14%	0.13%	1.01%
2014	1.32%	4.99%	-3.68%
2015	0.25%	-1.99%	2.24%
2016	0.29%	-0.09%	0.38%
Average Annual Growth Rate			
1997-2016	**1.06%**	**0.56%**	$\boxed{\textbf{0.50\%}}$
2006-2016	**0.81%**	**0.43%**	**0.39%**

[1]All growth rates are calculated logarthmically.

Table 7
Forecasted Growth in O&M Revenue Cap Index

Variable		**Forecasted Growth 2016-2021**
Input Price Index[1]	I	2.30%
Scale Trend Index[2]	Y	0.31%
Customers	YN	1.03%
Total Generation Capacity	YC	-0.63% [4]
Net Generation Volume	YG	-1.48% [4]
Base Productivity Trend[3]	X	0.50%
Growth in O&M Revenue Requirement	[I + Y - X]	2.11%

[1] Forecast of growth in the summary non-fuel O&M input price index.

[2] Scale index constructed from the Company's forecast of growth in scale subindexes and cost elasticity weights based on Table 1 econometric estimates using the formula growth Y = 0.64*growth YN + 0.22*growth YC + 0.14*growth YG.

[3] X factor is the trend in the non-fuel O&M productivity of U.S. vertically integrated electric utilities in the 1997-2016 sample period as reported on Table 6.

[4] Based on PSCo forecasts.

To calculate the pace of revenue requirement escalation for expenses that aren't tracked which Public Service proposes, we first removed the expected cost savings from Valmont and Cherokee from their 2016 historical test year total since these changes are expected to occur in 2017. Public Service proposes revenue requirements for non-fuel O&M expenses during the MYP which reflect its forecast of the cost of advanced grid and intelligence security ("AGIS"). The salary and wage portion of its revenue requirement for other non-fuel O&M expenses is escalated by 3% to account for expected wage increases in 2017 and then escalated by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses is frozen. The resultant revenue requirement for non-fuel O&M expenses not slated for tracker treatment averages 1.77% growth in the five years from 2016 (as normalized) to 2021.

The difference between the forecasted average growth in our O&M revenue escalator and the Company's proposed 1.77% growth over the same years is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 0.34%. Approved stretch factors in indexed ARMs of North American energy utilities typically range between 0 and 0.60% today. Stretch factors in the neighborhood of 0.3% are typically reserved today for average cost performers.

5. Need for Revenue Requirement Escalation when Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its *actual* revenue track its *allowed* revenue more closely. Many revenue decoupling systems have two basic components: a revenue *decoupling* mechanism ("RDM") and a revenue *adjustment* mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue, and adjusts rates to draw down these variances. Meanwhile, the RAM escalates allowed revenue between rate cases to provide relief for growing cost pressures. These mechanisms thus address different sources of financial attrition that utilities experience between rate cases. The RDM addresses *revenue*-related attrition, while the RAM addresses *cost*-related attrition. Other revenue decoupling systems have some automatic revenue escalation built into the RDM.

In the absence of automatic revenue escalation, decoupled revenue will not grow. Growth in billing determinants can cause base rates to fall. Meanwhile, cost tends to rise for various reasons that include growth in input prices and operating scale. For this reason, most approved decoupling systems have some form of automatic revenue escalation. Utilities operating without such escalation in their decoupling systems often file frequent rate cases. When developing a decoupling system, the *need* for automatic revenue escalation is thus less of an issue than its *design*.

Many decoupling systems of gas and electric utilities escalate allowed revenue only for growth in the number of retail customers.[17] The number of customers is an important driver of cost in its own right and is highly correlated with other scale variables that drive cost such as peak demand. The number of customers is usually the most important scale variable in PEG's econometric studies of electric utility cost.

Escalating revenue for customer growth reduces the need for rate cases but rarely eliminates it because cost has several other drivers. Utilities operating under decoupling systems that automatically escalate revenue only for customer growth therefore rarely agree to rate case

[17] This is sometimes accomplished by adjusting rates to hold revenue-per-customer or use per customer constant.

moratoriums. Some utilities have had RAMs that are "broad based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can reduce the need for rate cases substantially and thereby serve as the attrition relief mechanism in an MYP.

To illustrate the need for escalation of allowed revenue when a vertically integrated electric utility is subject to decoupling, we gathered data from FERC Form 1 and other publicly available sources on the trend in the pro-forma total cost of base-rate inputs in our sample of 54 American VIEUs. The sample period is 1998-2016. Costs considered in our study included most non-fuel O&M expenses, amortization, depreciation expenses, taxes, and a proforma return on net plant value.

Table 8 and Figure 1 provide results of this work. The table and figure also show the trends in the U.S. gross domestic product price index ("GDPPI") and the number of retail customers served by the sampled utilities. The GDPPI is the federal government's featured index of inflation in the prices of final goods and services in the US economy. Final goods and services include consumer products, capital equipment, and exports. The GDPPI tends to grow more slowly than the economy's input prices due to the brisk productivity growth of the economy.

Inspecting the results it can be seen that, over the full sample period, the 3.86% average annual growth rate in the non-fuel cost of the VIEUs substantially exceeded the corresponding trends in the number of customers served and the GDPPI. We have obtained similar results in analogous studies for energy distribution.[18] This work suggests that regulators can permit escalation of the revenue requirement for customer growth with little concern that it will produce overearning.

[18] See, for example, the testimony by senior author Mark Newton Lowry in Pennsylvania Public Utilities Commission Docket M-2016-2518883 for the Natural Resources Defense Council, February 2016.

Table 8

Comparing Trends in VIEU Cost and Customers and Inflation[19,20]

	Non-Fuel Cost [%] [A]	Customers [%] [B]	GDPPI [%] [C]
1998	3.37%	1.83%	1.08%
1999	-0.37%	1.46%	1.42%
2000	5.92%	1.98%	2.25%
2001	0.07%	1.45%	2.26%
2002	2.20%	1.43%	1.52%
2003	2.40%	1.38%	1.98%
2004	3.96%	1.51%	2.71%
2005	3.46%	1.41%	3.17%
2006	2.96%	0.53%	3.02%
2007	6.06%	1.46%	2.63%
2008	4.76%	0.98%	1.91%
2009	4.80%	0.42%	0.78%
2010	7.32%	0.59%	1.22%
2011	4.09%	0.08%	2.04%
2012	2.92%	0.55%	1.82%
2013	4.02%	0.78%	1.60%
2014	6.14%	0.72%	1.78%
2015	3.96%	0.93%	1.06%
2016	5.35%	1.01%	1.31%
Average Annual Growth Rates			
1998-2016	**3.86%**	**1.08%**	**1.87%**
2008-2016	**4.82%**	**0.67%**	**1.50%**

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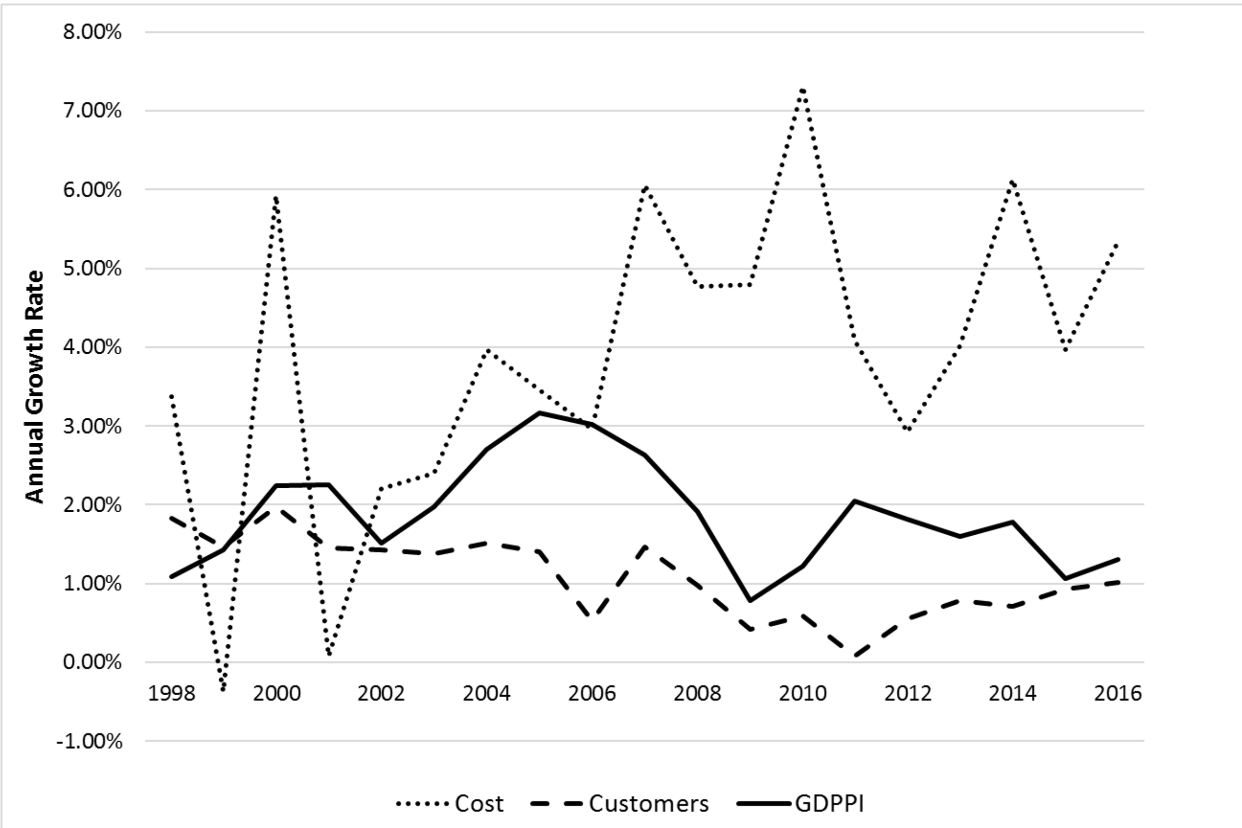
[19] Data Sources: FERC Form 1 (cost data), the Edison Electric Institute (allowed ROE), EIA Form 861 and FERC Form 1 (customers), and the Bureau of Economic Analysis (GDPPI). Cost is calculated as reported O&M expenses less fuel, purchased power, customer service and information, transmission by others, transmission dispatching, regional market, and miscellaneous power supply and transmission expenses plus an estimate of capital cost. Capital cost was calculated as the pro forma return on rate base plus depreciation and tax expenses.

[20] Growth rates are calculated logarithmically.

Figure 1

Comparing Trends in VIEU Cost and Customers and Inflation



6. Performance Impact of Test Years

To address the impact of test years on incentives for good cost management we developed an econometric model of the growth of real non-fuel electric O&M expenses. One driver of real O&M cost growth was identified in this research: growth in the scale trend index we constructed for Table 7. We added to the model a binary variable with a value of one for companies that were subject to historical test years in any and all rate case filings that occurred in the 1997-2016 sample period. If this variable had a negative and statistically significant parameter estimate, it would suggest that historical test years tend to slow annual cost growth.

Results of the exercise can be found in Table 9. It can be seen that the parameter estimate for the scale index was positive and highly significant, indicating that growth in scale tended to accelerate cost growth. The positive value of the constant term indicates a tendency for O&M cost growth to accelerate over time for reasons not captured by other model variables.

The parameter estimate for the historical test year dummy was positive, suggesting that HTYs *accelerated* cost growth, but was close to zero and highly insignificant. We accordingly cannot reject the hypothesis that a historical test year had no effect on real non-fuel cost growth. A similar conclusion was drawn on this subject with respect to vertically integrated electric utilities in our previous testimony for Public Service. These empirical results square with our experience, gathered over many years of incentive regulation research, that the choice of a test year for rate cases has little impact on cost performance incentives.

The explanatory power of the model was low. Cost growth evidently fluctuated from year to year due to miscellaneous business conditions that are difficult to measure. The parameter estimates are nonetheless meaningful and shed light on the test year performance impact.

Table 9
Econometric Model of Vertically Integrated Electric Utility Real Non-Fuel O&M Cost Growth

VARIABLE KEY

DY = Growth in Elasticity Weighted Scale Index
HTY = Historic Test Year Binary Variable
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
DY	0.313	3.328	0.001
HTY	0.002	0.277	0.782
Trend	0.000	-0.762	0.446
Constant	0.005	0.806	0.420

Rbar-Squared	0.009
Sample Period	1997-2016
Number of Observations	1080

APPENDIX

This Appendix provides additional and more technical details of our empirical research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods, unit cost indexes, and productivity calculations.

A.1 Form of the Econometric Cost Model

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

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot V_{h,t}\,. \qquad \text{[A1]}$$

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

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t}\,. \qquad \text{[A2]}$$

In the double log model the dependent variable and the business condition variables (customers and deliveries) are all logged. This specification makes 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.

Elasticity estimates are useful 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. This model specification is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\begin{aligned}\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ + a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t}\end{aligned}\,. \qquad \text{[A3]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln V_{h,t} \cdot \ln N_{h,t}$ 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 deliveries may depend on the number of customers in the service territory.

The translog form is an example of a “flexible” functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model’s cost prediction falls.

A.2 Econometric Model Estimation

A variety of estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares (“OLS”), is readily available in econometric software. Another class of procedures, called generalized least squares (“GLS”), is appropriate under assumptions of more complicated and realistic 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 scale.

In order to achieve a more efficient estimator, we corrected for autocorrelation and groupwise heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG using the widely-used R statistical software program.

Note, finally, that the model specification was determined using 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.

A.3 Unit Cost Indexes

Each summary unit cost index that we calculated for Public Service in an MYP year like 2018 is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{PSCO,2018} = \frac{Cost_{PSCO,2018}}{Scale_{PSCO,2018}} \quad [A4]$$

The cost index is the ratio of the Company's forecasted 2018 cost, deflated to 2016 dollars, to the mean cost for the peer group in 2016. Each scale index compares the forecasted 2018 values for Public Service to the corresponding sample norms in 2016. Thus,

$$Unit\ Cost_{PSCO,2018} = \left(\frac{Cost_{PSCO,2018}}{\overline{Cost_{2016}}}\right) \Bigg/ \sum se_i * \frac{Y_{PSCO,i,2018}}{\overline{Y_{i,2016}}} \quad [A5]$$

Here $Cost_{PSCO,2018}$ is the real revenue requirement projected for Public Service, $Y_{PSCO,i,2018}$ is the Company's forecasted value of scale variable *i*, and $\overline{Cost_{2016}}$ and $\overline{Y_{i,2016}}$ are the corresponding 2016 peer group means. The denominator of this formula takes a weighted average of the scale variable comparisons. The weight for each scale variable *i* (se_i) is its share in the sum of the corresponding cost elasticity estimates from the corresponding econometric cost model.

A.4 Additional Details on O&M Productivity Trend Research

We calculated an O&M productivity trend index for each company in our sample. The annual growth rate in each company's productivity index is the difference between the growth rates of its scale and input quantity indexes. These growth rates are calculated logarithmically.

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Scale_t}{Scale_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right)$$

The long-run trend in the productivity index was calculated as its average annual growth rate over the full sample period.

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