**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 3, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

*** * * * ***

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-______E**

SUMMARY OF THE DIRECT TESTIMONY OF MARK N. LOWRY

Mark N. Lowry is President of Pacific Economics Group Research, LLC ("PEG"). A former Pennsylvania State University energy economics professor, Dr. Lowry pioneered the use of rigorous productivity and benchmarking research in North American energy utility regulation. He is also an expert on multi-year rate plans ("MYPs"), forward test years ("FTYs"), and revenue decoupling.

In addition to his management duties, Dr. Lowry serves as principal investigator for many of his company's projects. He supervises research on utility performance and new forms of regulation, advises clients, and testifies in proceedings across North America. Work for a mix of utilities, regulators, consumer and environmental groups, and government agencies has given his practice a reputation for objectivity and dedication to good regulation.

In his Direct Testimony for Public Service Company of Colorado ("Public Service" or the "Company") in this proceeding, Dr. Lowry provides an overview of the MYP approach to regulation, discussing its common provisions, precedents, and rationale. He also provides an appraisal of the plan Public Service is proposing in this proceeding for its electric services. His appraisal draws on his decades of experience in the field and on statistical cost research undertaken for this proceeding. His research used well-established indexing and benchmarking methods. Rigorous statistical studies in support of their future revenue requirements are rarely commissioned by U.S. utilities. Dr. Lowry also presents empirical results on the impact of historical test years on cost performance and on the need for revenue requirement escalation when a company is subject to revenue decoupling.

Dr. Lowry explains in his testimony that the efficacy of the traditional cost of service approach to regulation varies with the business conditions utilities face. When conditions are chronically unfavorable, regulatory cost is high and frequent rate cases can weaken performance incentives. Business conditions facing electric utilities today are much less favorable than in the years before 1968 when cost of service regulation ("COSR") became a tradition.

Dr. Lowry explains in his testimony several advantages of the MYP approach to regulation under today's business conditions. Regulation is more efficient and effective. Rate growth can be smoother and more predictable. Benchmarking and productivity research are often used in MYP design, and these are valuable complements to prudence reviews in ensuring that rates offer customers good value.

Rate cases are held less frequently under MYPs, especially when traditional regulation uses historical test years in rate cases. Rate adjustments that are made give a utility a reasonable chance to earn its authorized rate of return without closely tracking the costs that it actually incurs. These features of MYPs can strengthen utility performance incentives. Managers experience a business environment more like that which their commercial and industrial customers face. Research by Dr. Lowry has revealed that a reduction in the frequency of rate cases can improve utility performance. Benefits can be shared between utilities and their customers. Regulators have acknowledged the streamlined regulation and stronger performance incentives that MYPs can provide.

Dr. Lowry also explains special advantages of MYPs in electric utility regulation today. Strong performance incentives are desirable in a period when good performance is needed to meet competitive challenges. Utility incentives to embrace conservation, peak load management, and distributed generation and storage can be strengthened. Streamlined regulation frees up resources to consider the industry's many challenging generic regulatory issues. Marketing flexibility can be facilitated at a time when the need for flexibility is rising. An MYP is a useful complement to the approved revenue decoupling system for Public Service since it provides more automatic revenue escalation to address cost growth.

There are numerous precedents for MYPs for electric and gas utilities. Impetus for MYPs has often come from regulators and other policymakers. Use of MYPs by vertically integrated electric utilities has been growing rapidly in the United States. Colorado's commission has twice approved MYPs for electric services of Public Service, as well as plans for local telecommunications carriers. Use of MYPs to regulate energy utilities is becoming the norm in populous provinces of Canada and in countries overseas.

Public Service is proposing a comprehensive MYP for its electric services which is in line with industry precedent and similar in many respects to the Company's previously approved plans. A rate case would not be held for several years. The trajectory of electric rates would be smoothed and more predictable.

Statistical research supervised by Dr. Lowry explored whether the revenue requirements that the Company proposes for its non-fuel operation and maintenance ("O&M") expenses during the plan years offer customers good value. Using two well-established benchmarking methods, he found that the proposed revenues are commensurate with good cost performance. Moreover, the proposed *rate* of revenue escalation is less than would be yielded by an O&M revenue escalation index that Dr. Lowry developed. His revenue escalation index would also be useful in a rate case with a single forward test year. Further support for the proposal comes from the extensive information that Public Service has provided about its electric business plan.

With respect to his other empirical research for this proceeding, Dr. Lowry found no evidence that historical test years improve the cost performance of vertically integrated electric utilities. He also shows why utilities operating under revenue decoupling need some form of automatic revenue escalation. Due to miscellaneous drivers that include input price inflation, growth in the non-fuel cost of vertically integrated electric utilities makes it very unlikely that escalation of allowed revenue for customer growth will produce overearning.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
AGIS	Advanced Grid Intelligence and Security
ARM	Attrition Relief Mechanism
CACJA	Clean Air Clean Jobs Act
Capex	Capital Expenditures
CMP	Central Maine Power
Commission	Colorado Public Utilities Commission
COSR	Cost of Service Regulation
DGS	Distributed Generation and Storage
DSM	Demand-Side Management
ECM	Efficiency Carryover Mechanism
EEI	Edison Electric Institute
ESM	Earnings Share Mechanism
FERC	Federal Energy Regulatory Commission
FTY	Forward Test Year
GDPPI	Gross Domestic Product Price Index
HTY	Historical Test Year
LRAM	Lost Revenue Adjustment Mechanism

Acronym/Defined Term	**Meaning**
MFP	Multifactor Productivity
MYP	Multi-year Rate Plan
O&M	Operations and Maintenance
PBR	Performance-Based Regulation
PEG	Pacific Economics Group Research, LLC
PIM	Performance Incentive Mechanism
Public Service, or the Company	Public Service Company of Colorado
QSP	Quality of Service Plan
RAM	Revenue Adjustment Mechanism
RDM	Revenue Decoupling Mechanism
ROE	Rate of Return on Equity
UDC	Utility Distribution Company
UPC	Usage per Customer
U.S.	United States
VIEU	Vertically Integrated Electric Utility

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

*** * * * ***

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Newton Lowry. My business address is 44 East Mifflin Street Suite 601, Madison, WI 53703.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the President of Pacific Economics Group Research LLC ("PEG").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service" or the "Company").

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am responsible for managing PEG, a consulting firm that works primarily in the field of utility economics. Together with other members of PEG's team, I pioneered the use of rigorous benchmarking and productivity research in the regulation of North American energy utilities. I am also an expert on multi-year rate plans ("MYPs"), forward test years ("FTYs"), and revenue decoupling.

After more than two decades of work in these fields, I continue to serve as principal investigator for many of PEG's projects. I supervise research on utility performance and trends in regulation, consult with clients, and provide expert witness testimony. Work for a mix of utilities, regulators, government agencies, trade associations, and consumer and environmental groups has given my practice a reputation for objectivity and dedication to good regulation.

Before entering consulting I was a professor teaching energy economics at the Pennsylvania State University. I have chaired several conferences on utility regulation and performance measurement and have published papers in these and other fields. I earned a Ph.D. in applied economics at the University of Wisconsin. An abbreviated version of my qualifications is set forth in my Statement of Qualifications after the conclusion of my Direct Testimony. Attachment MNL-1 is a résumé containing further details of my qualifications, duties, and responsibilities.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. Public Service is proposing an MYP for its electric services in this proceeding. The plan includes revenue decoupling which, as I understand it, was recently approved by the Colorado Public Utilities Commission ("Commission") for the Company in another proceeding. The revenue requirement would be escalated by a hybrid mechanism. Capital revenue would be based on a capital cost forecast. Revenue for O&M expenses would reflect a forecast of expenses for advanced grid intelligence and security ("AGIS"). Revenue for other labor operation and maintenance ("O&M") expenses would be escalated by 3 percent from the normalized 2016 level to account for expected wage increases in 2017 and then escalated by 2 percent in each of the 2018, 2019, 2020 and 2021 Forward Test Years. Revenue for other material and service O&M expenses would be unchanged.

Rates of Colorado utilities can reflect expected future business conditions, but in past proceedings some parties have questioned the reasonableness of and support for the Company's proposals. Revenue decoupling will reduce concerns about *billing determinant* forecasts but there may still be concerns about proposed revenue requirements. Parties have also claimed that the historical test years ("HTYs") traditionally used in Colorado incentivize better utility cost performance.

My Direct Testimony provides the Commission with background information on the MYP approach to regulation. My analysis also supports the use of FTYs in rate cases. Additionally, I appraise the plan Public Service is proposing for its electric services.

I also discuss in my testimony four empirical tasks I undertook for Public Service to inform the Commission on key issues in this proceeding. One task was to benchmark the Company's proposed revenue requirements for non-fuel O&M expenses in the four MYP years. Another was to develop an index-based escalator for O&M revenue and use it to appraise the reasonableness of the Company's proposed *rate* of O&M revenue escalation. This escalator is also useful for establishing revenue requirements in forward test year rate cases.

A third task I undertook was to explore the need for automatic revenue requirement escalation when a utility operates under revenue decoupling. A fourth was to use statistical methods to consider whether HTYs improve utility cost performance. Our empirical work used a sizable dataset on operations of United States ("U.S.") vertically integrated electric utilities ("VIEUs").

Q. ARE YOU SPONSORING ANY OTHER ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. Attachment MNL-2 is a report I prepared on our empirical research ("PEG Report") for Public Service. This report also provides background information on benchmarking and productivity measurement.

Q. HAVE YOU ALSO SUBMITTED TESTIMONY IN PROCEEDING NO. 17AL-0363G?

A. Yes, I submitted direct testimony in that proceeding where I likewise discuss MYPs, appraise the Company's proposed plan for its gas services, and consider the cost impact of historical test years.

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

A. Public Service witness Ms. Alice Jackson presents the Company's proposed MYP. Several Company witnesses explain the Company's budgeting and cost management procedures to help show why the proposed revenue requirements are reasonable.

My Direct Testimony and empirical report provide a qualitative assessment of the reasonableness of the Company's proposed plan and a quantitative assessment of the proposed revenue requirements for the MYP years. My work on the cost impact of HTYs and the need for revenue escalation under decoupling are, similarly, an attempt to shed light on these issues using statistical methods and industry data.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE MYP APPROACH TO REGULATION?

A. I believe that MYPs are a promising alternative to traditional cost of service regulation ("COSR"). COSR became a tradition under business conditions that were much more favorable than those that utilities face today. MYPs work better under today's business conditions. Rate trajectories can be smoother and more predictable. Regulation can be more efficient and effective, freeing resources to better address important generic issues. Utility performance can improve, and benefits can be shared with customers. These advantages of MYPs have been recognized by regulators. Incentives for utilities to embrace demand-side management ("DSM") and distributed generation and storage ("DGS") can be strengthened. Benchmarking and productivity research are often used in plan design, a customer protection that challenges utilities to outperform their peers.

MYPs are a well-established approach to electric utility regulation. In the United States, use of MYPs to regulate vertically integrated electric utilities like Public Service has grown considerably in recent years. This Commission has already used MYPs twice to regulate the Company's electric services. MYPs are extensively used for electric utilities in Canada and many countries overseas.

Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR BENCHMARKING STUDY?

A. Based on the study detailed in the PEG Report, which used two well-established statistical benchmarking methods, I conclude that the Company's proposed revenue requirements for non-fuel O&M expenses are low by industry standards.

Q. WHY DID YOU DEVELOP AN O&M REVENUE ESCALATOR AND WHAT WERE THE RESULTS?

A. Index-based formulas have been used to escalate O&M revenue requirements in MYPs and forward test year rate cases. We developed an index to escalate the revenue requirement for the Company's non-fuel O&M expenses which is based on cost theory, statistical research, and regulatory precedent. We used the index to appraise the rate of non-fuel O&M revenue escalation which Public Service proposes for the four MYP years. This research indicates that the Company's proposed escalation for non-fuel O&M revenue provides material customer value.

Q. WHAT REGULATORY SYSTEM MAKES SENSE FOR THE COMPANY'S ELECTRIC SERVICES?

A. I believe that the MYP approach to regulation makes sense for the Company's electric services. Rate growth would be smooth and predictable. Regulation would be more efficient, and better performance can be encouraged.

Public Service is proposing in this proceeding an MYP for its electric services which has ample precedent. Features of the proposed plan are commensurate with those of MYPs throughout the country. Several provisions of the plan have been in the plans the Commission has previously approved. There are extensive customer protections. My statistical work suggests that the proposed revenue requirement for non-fuel O&M expenses offers customers good value. The alternative to an MYP for the Company's electric services is frequent rate cases that involve high regulatory cost and weak performance incentives.

Q. WHAT ARE THE IMPLICATIONS OF THE COMMISSION'S RECENT DECISION TO APPROVE REVENUE DECOUPLING FOR THE COMPANY'S ELECTRIC SERVICES?

A. As a longtime advocate of decoupling who has testified in support of decoupling for the Natural Resources Defense Council and other environmental groups, I strongly support inclusion of decoupling in MYPs today. Decoupling strengthens utility incentives to embrace DSM and DGS and reduces uncertainty about billing determinants in forward test year rate cases. However, a companion mechanism was not approved to escalate the revenue requirements for residential and small commercial customers for gradual growth in the numbers of these customers. This is unfortunate since a revenue decoupling mechanism by itself slows revenue escalation. Utilities have traditionally relied on revenue escalation between rate cases to help finance growth in their fixed costs. Revenue decoupling is most commonly combined with escalation of the revenue requirement for customer growth. The Commission rejected this approach on the grounds that it might over-recover fixed cost. I present results of empirical research that show that the base rate revenue requirements of vertically integrated electric utilities tend to grow much more rapidly today than the number of customers that they serve. Thus, over-recovery of fixed cost is unlikely from customer escalation.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE HTY INCENTIVE ISSUE?

A. After examining trends in non-fuel O&M expenses of VIEUs operating under different types of test years, I find no support for the assertion that HTYs strengthen cost performance incentives. This is consistent with my view that the kind of test year used in a rate case has little effect on incentives. MYPs provide a better means of strengthening incentives, as I discuss later in my testimony.

II. THE MYP APPROACH TO REGULATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. I will explain in this section the MYP approach to regulation and discuss salient MYP precedents. The general rationale for using MYPs is then set forth.

A. Components of a Multiyear Rate Plan

Q. WHAT ARE THE BASIC PROVISIONS OF THE MYP APPROACH TO REGULATION?

A. MYPs are a common form of performance-based regulation ("PBR"). Basic provisions of such plans are summarized in the plan design checklist I present in Figure MNL-D-1 below. In Section III I will discuss certain elements of this checklist in more detail.

Figure MNL-D-1 MYP Plan Design Checklist

MYP Checklist

- Plan Term ☐
- Attrition Relief Mechanism ☐
- Cost Trackers ☐
- Revenue Decoupling ☐
- Performance Metric System ☐
- Earnings Sharing and Off Ramps ☐
- Marketing Flexibility ☐
- Low Income Provisions ☐
- Plan Termination Provisions ☐

Q. PLEASE EXPLAIN THE ATTRITION RELIEF MECHANISM ("ARM") REFERRED TO IN THE CHECKLIST.

A. Rate cases are held infrequently under the MYP approach to regulation (typically every three to five years). There is thus often a need to adjust rates for changing business conditions between rate cases. Here is a generic formula for revenue requirement escalation in an MYP:

$$growth\ Revenue = growth\ ARM + Y + Z. \qquad [1]$$

The ARM permits revenue to grow in the face of cost pressures without closely tracking the cost that the utility actually incurs. I discuss ARM design further in Section 3 of my testimony below.

Q. PLEASE EXPLAIN THE Y- AND Z-FACTOR TERMS IN THIS FORMULA.

A. Costs that are difficult to address with the ARM may be addressed separately using cost trackers and associated rate riders or deferral arrangements. The "Y factor" indicates the revenue adjustments for costs, such as energy procurement expenses, which are chosen in advance for tracker treatment. The "Z factor" indicates the rate adjustments for miscellaneous changes in cost, which are hard to foresee and largely beyond the control of the utility, that may occasionally be accorded tracker treatment. Events that can trigger a Z factor adjustment include government mandates (e.g., to increase system undergrounding or relocate facilities due to highway construction) and force majeure events such as severe storms.

Q. WHAT IS THE PERFORMANCE METRIC SYSTEM REFERRED TO IN THE PLAN DESIGN CHECKLIST?

A. Performance metric systems aid measurement of utility performance in areas of special concern to customers and the public. These systems typically involve several metrics. Targets are established for some metrics, and performance can be gauged by comparing the utility's value to the target. Some metrics are components of performance incentive mechanisms ("PIMs") that link revenue to measured performance in targeted areas. In multiyear rate plans, PIMs most commonly strengthen incentives for utilities to maintain or improve reliability and customer service quality.

Q. CAN PROVISIONS BE ADDED TO PLANS TO STRENGTHEN UTILITY INCENTIVES TO EMBRACE EFFICIENT DSM AND DGS?

A. Yes. Utility expenditures on DSM are usually tracked. Performance incentive mechanisms can be added to plans which reward utilities for successful DSM and DGS initiatives. Revenue decoupling and/or lost revenue adjustment mechanisms can reduce the sensitivity of earnings to DSM and DGS.

Q. WHAT ARE THE EARNING SHARING AND OFF-RAMP MECHANISMS REFERRED TO IN THE PLAN DESIGN CHECKLIST?

A. Some MYPs feature an earnings sharing mechanism ("ESM") that shares surplus or deficit earnings, or both, between utilities and their customers which result when the utility's rate of return on equity ("ROE") varies from the commission-approved target. Off-ramp mechanisms permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs.

Q. WHAT ARE THE MARKETING FLEXIBILITY AND PLAN TERMINATION PROVISIONS REFERRED TO IN THE CHECKLIST?

A. Some MYPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. These provisions can help utilities respond to the complex and changing needs of customers. Utilities may also be permitted (or required) to gradually redesign rates for standard services during the plan in fulfillment of commission-approved goals. For example, default rate designs for residential customers can move towards a time of use pattern.

Plan review and termination provisions are also important in MYPs. Some plans provide for a review towards the end of the term. To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited when the plan expires. For example, mid-term reviews sometimes result in a plan extension without a general rate case. If a rate case does occur, an efficiency carryover mechanism ("ECM") can permit the utility to keep a share of any lasting cost savings that are embodied in the new revenue requirement.

B. MYPs and Traditional Cost of Service Regulation

Q. WHAT IS THE RATIONALE FOR USING MYPS?

A. To explain the rationale for MYPs I will first appraise the cost of service approach to regulation, still widely used in the U.S., and then discuss reasons why some jurisdictions have adopted the alternative MYP approach.

Q. WHAT ARE THE BASIC FEATURES OF COSR?

A. Under COSR the base rates that compensate utilities for costs of capital, labor and materials are reset in rate cases at levels that more effectively recover a utility's prudent cost of service. Rate cases occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Historical test years were traditionally used in rate cases but forward test years are now used in many jurisdictions where COSR is practiced.

Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue has traditionally been drawn from usage charges (e.g., charges per kWh of sales or kW of peak demand). The "horse race" between cost and system use is thus an important determinant of the need for rate cases.

In the short and medium term, costs of base rate inputs are driven more by growth in system *capacity* (e.g., the capacity to supply peak load and deliver power to scattered locations) than by growth in system *use*. They are for this reason often called “fixed” costs even though they grow. The number of customers served is an important driver of capacity growth and is highly correlated with other drivers such as expected peak demand.[1] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in usage per customer (“UPC”).

Under legacy rate designs, with their high usage charges, UPC growth bolsters earnings, reducing the need for rate cases to finance cost growth. A decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between depreciation in the value of existing assets due to depreciation and capital expenditures (“capex”) that don’t automatically trigger revenue growth.

Q. WHAT IS YOUR CRITIQUE OF COSR?

A. The regulatory cost of COSR is high for utility commissions, utilities, and other stakeholders when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that a jurisdiction has many utilities and the business conditions facing utilities are chronically unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

---

[1] Customer growth is highly correlated with peak demand growth because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.

Regulators understandably take measures to contain regulation's costs. Some of these measures have adverse consequences. For example, the scope and thoroughness of prudence reviews are contained, and this weakens utility incentives to perform well. Expanded use of cost trackers can reduce rate case frequency and thereby helps to preserve incentives to contain costs that are not tracked. However, incentives to contain newly tracked costs may be weakened unless these costs are carefully monitored.

This analysis suggests that the efficacy of COSR varies with the business conditions that utilities face. When conditions are favorable, revenue growth between rate cases roughly matches (and can even exceed) cost growth. Rate cases are infrequent, regulatory cost is low, and performance incentives can be strong. When conditions are chronically unfavorable, however, cost tends to grow more rapidly than revenue. Utilities respond by filing rate cases more frequently and/or by asking for more expansive cost trackers. Regulatory cost can be high and performance incentives can be weak. Utility performance tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

Frequent rate cases are especially likely under chronically unfavorable business conditions when historical test years are used to set revenue requirements. That is because HTYs do not fully recognize the tendency of cost to grow more rapidly than billing determinants between the test year and the rate effective year. HTYs made more sense in the golden age of COSR when cost and billing determinant growth were more balanced.

Note, also, that rates that closely track a utility's cost of service also produce occasional rate "bumps". These can harm customers and make it difficult for them to budget for their energy needs.

Q. DO REGULATORS SOMETIMES CONCUR WITH YOUR ANALYSIS?

A. Yes. For example, Alberta's utility commission ordered all gas and electric power distributors in the province to operate under MYPs after years of frequent rate cases. In announcing the start of the generic hearing that ultimately led to this decision the commission stated the following:

> This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources…. Regulators…must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing…The Commission is seeking a better way to carry out its mandate.[2]

Q. IS THERE EMPIRICAL EVIDENCE TO SUBSTANTIATE YOUR CLAIM THAT FREQUENT RATE CASES CAUSED BY ADVERSE BUSINESS CONDITIONS IMPAIR UTILITY PERFORMANCE?

A. Yes. As one example, the federal government calculated an index of the multifactor productivity ("MFP") trend of the electric, gas, and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[3] In recently-

---

[2] Alberta Utilities Commission, "AUC letter of February 26, 2010," pages 1-2, Exhibit 1.01 in Proceeding 566.

[3] Computation of this index ended in 1998. For a discussion of this research, see John L. Glaser, "Multifactor Productivity in the Utility Services Industries," *Monthly Labor Review*, May 1993, pp. 34-49.

published work for Lawrence Berkeley National Laboratory, I compared the MFP trend of this sector in an extended period when business conditions for utilities were favorable with the trend in a period when conditions were unusually unfavorable. Since rate cases were more frequent when business conditions were unfavorable, this is a useful test of the performance problems that can arise under COSR.

Q. PLEASE DISCUSS THE CONCEPT OF PRODUCTIVITY.

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity grows to the extent the real (inflation-adjusted) unit cost of utilities decline. Drivers of productivity growth include technological change, the realization of scale economies, and the elimination of inefficiencies. A *multifactor* productivity index considers productivity in the use of multiple inputs (e.g., capital, labor, materials and services). My report on PEG's empirical work in Attachment MNL-2 discusses productivity more extensively.

Q. HOW DID YOU GAUGE THE ADVERSITY OF BUSINESS CONDITIONS FACING UTILITIES?

Figure MNL-D-2 presents evidence on two of the most important sources of potential financial attrition for gas and electric utilities:

- trends in residential and commercial energy UPC; and

- price inflation, measured here by the gross domestic product price index ("GDPPI").[4]

We constructed from these data summary indicators of the potential attrition facing gas and electric utilities. The indicator for each kind of utility is the difference between inflation and the average of the growth in residential and commercial energy UPC. The table itemizes trends in these attrition indicators over several subperiods between 1931 and 2015.

The table shows show that these business conditions tended to be favorable to utilities on balance from the late 1920s until the late 1960s. Inflation was generally slow. Gas and electric UPC grew rapidly. In addition, rapid demand growth presented outsized opportunities to realize scale economies.

[4] The GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.

Figure MNL-D-2 Indicators of U.S. Energy Utility Financial Attrition (1927-2014)

Multiyear Averages	Electricity UPC			Natural Gas UPC			GDPPI Inflation[4]	Summary Attrition Indicators	
	Residential[1]	Commercial[1]	Average	Residential[2]	Commercial[3]	Average		Electric	Natural Gas
			[A]			[B]	[C]	[C-A]	[C-B]
1927-1930	7.06%	6.67%	6.86%	NA	NA	NA	NA	NA	NA
1931-1940	5.45%	2.00%	3.73%	0.54% [5]	0.94% [5]	0.74%	-1.59%	-5.31%	-2.33%
1941-1950	6.48%	5.08%	5.78%	3.90%	4.60%	4.25%	5.26%	-0.52%	1.01%
1951-1960	7.53%	6.29%	6.91%	3.40%	3.16%	3.28%	2.42%	-4.49%	-0.86%
1961-1967	5.37%	10.48%	7.93%	2.42%	4.94%	3.68%	1.77%	-6.15%	-1.90%
1968-1972	6.38%	6.43%	6.41%	1.78%	3.97% [7]	2.88%	4.66%	-1.75%	1.78%
1973-1982[6]	1.34%	1.61%	1.47%	-2.15%	-1.10%	-1.63%	7.24%	5.77%	8.86%
1983-1986[6]	0.90%	2.26%	1.58%	-3.07%	-4.26%	-3.66%	3.13%	1.55%	6.79%
1987-1990	1.39%	2.29%	1.84%	-1.25%	1.33%	0.04%	3.33%	1.49%	3.29%
1991-2000	1.15%	1.68%	1.41%	-0.37%	-1.77%	-1.07%	2.03%	0.62%	3.10%
2001-2007	0.73%	0.64%	0.68%	-2.12%	0.30%	-0.91%	2.47%	1.79%	3.38%
2008-2015	-0.47%	-0.20%	-0.34%	-0.85%	-1.55%	-1.20%	1.53%	1.87%	2.73%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, *Historical Natural Gas Annual 1930 Through 1999* (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014). U.S. Bureau of Mines, *Minerals Yearbook,* various issues prior to 1968.

[3] Includes vehicle fuel. Sources: U.S. Bureau of Mines, *Minerals Yearbook*, various issues prior to 1968. Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. "Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers," Revised April 28, 2017.

[5] Growth rates are for 1932-1940. Data are not available before 1931.

[6] Shaded years had unusually unfavorable business conditions.

[7] Prior to 1968, the reported commercial gas data do not include values for other consumers (e.g., deliveries to municipalities and public authorities).

These conditions deteriorated after 1967 and were especially unfavorable from 1973 to 1976. Rate cases were much more frequent during these years as shown in Figure MNL-D-3.

Figure MNL-D-3 U.S. Electric Utility Rate Cases: 1948-1977[5]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

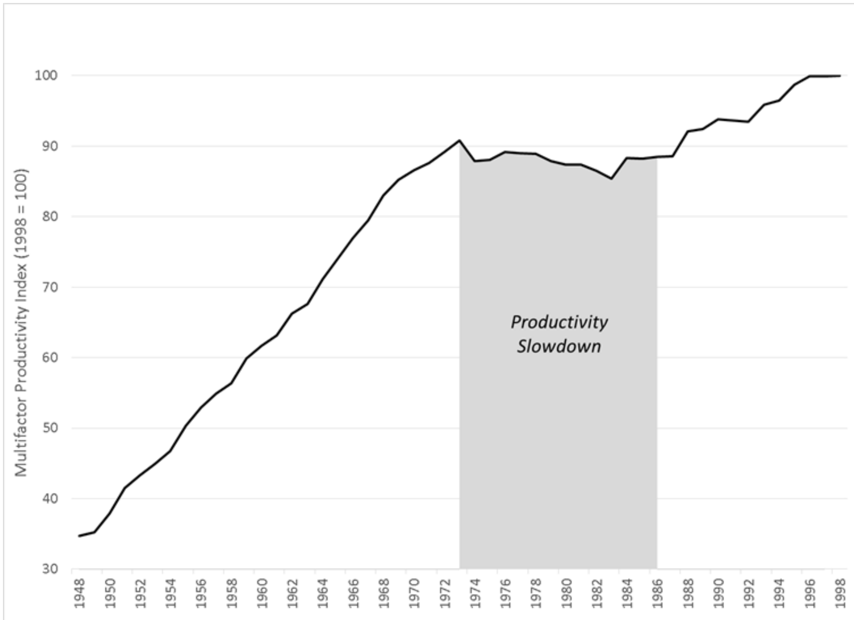
Q. DID INDUSTRY PRODUCTIVITY GROWTH VARY WITH THE ADVERSITY OF BUSINESS CONDITIONS?

A. Yes. Figure MNL-D-4 shows the trend in MFP growth of the electric, gas, and sanitary sector of the economy over the 50 years from 1949 to 1998. It can be seen that the MFP growth of the sector was remarkably brisk until 1968, averaging 4.4 percent annually compared to the 2.2 percent trend in the MFP of the entire private business sector of the economy.

The MFP trend of electric, gas and sanitary utilities fell to 2.31 percent during the 1968-72 period of accelerating inflation and to zero during the following years of markedly unfavorable business conditions. Both capital and labor productivity growth of this utility sector slowed markedly. MFP growth of the electric, gas and sanitary utilities trailed that of the U.S. private business sector by around 72 basis points annually on average during these years.[6]

[5] *Ibid*.
[6] A basis point is one-hundredth of 1 percent.

Figure MNL-D-4 Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948-1998)[7]



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS RESEARCH?

A. I conclude that the MFP growth of the utility sector was much more rapid in the decades before 1973 when business conditions generally favored utilities and rate cases were infrequent. This was the "golden age" of COSR when this regulatory system became a tradition in the United States.

[7] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

C. Advantages and Disadvantages of MYPs

Q. DOES THE MYP APPROACH TO REGULATION HAVE ADVANTAGES OVER COSR?

A. Yes. One key advantage is the potential of MYPs to encourage better utility performance. Another is their ability to make regulation more efficient. These benefits can be shared with customers. Rate growth can be smoother and more predictable.

Q. HOW CAN MYPS ENCOURAGE GOOD UTILITY PERFORMANCE?

A. As I noted above, the attrition relief mechanism of an MYP can provide timely rate escalation that permits an extension of the period between rate cases and reduced use of cost trackers. Between rate cases, revenue escalation from the ARM is based on a forecast of the utility's cost, industry cost trends, or both, and not on growth in the exact cost that the utility incurs. This increases opportunities for utilities to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). Loosening the link between a utility's cost and its revenue gives managers an operating environment more like that which their commercial and industrial customers experience. Avoiding a full true up of revenue to cost when the plan expires can magnify the incentive "power" of an MYP.

The PIMs added to MYPs also play a role in encouraging good performance. For example, I have noted that MYPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall materially if the quality of its offerings falls below industry norms. Moreover, customers of firms in competitive markets provide no relief if a company's safety problems trigger costly lawsuits. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.

Q. HISTORICAL TEST YEARS ARE SOMETIMES USED IN RATE CASES. DOESN'T THIS FEATURE PRODUCE COMPARABLY STRONG PERFORMANCE INCENTIVES IN A COSR REGIME?

A. No. No matter what kind of test year is used, rate cases provide an opportunity for a utility to hold its cost below the established revenue requirement for the rate effective year Timely adjustments to rates for external business conditions like input price inflation do not weaken performance incentives. Prices in competitive markets, after all, routinely change with business conditions. Air fares, for example, tend to rise with jet fuel prices.

When business conditions are adverse, the revenue from a historical test year rate case will be less compensatory. However, utilities have the option under COSR to file rate cases as needed. Unfavorable business conditions that cause undercompensation from rate cases encourage utilities to file rate cases more frequently, and this erodes incentives. An MYP reduces the frequency of rate cases and can provide stronger performance incentives while also providing timely and compensatory rate relief through the ARM.

Q. DO MYPS HAVE OTHER ADVANTAGES?

A. Yes. MYPs can also encourage good utility performance by increasing operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency means that the prudence of utility actions must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., relatively low O&M expenses that do not reduce service quality). Knowledge of stronger incentives informs prudence reviews when they are made. One area where the advantage of MYPs in facilitating operating flexibility has been most developed is marketing flexibility.

With stronger performance incentives and greater operating flexibility, MYPs can encourage better utility performance. The strengthened performance incentives and reduced preoccupation with rate cases which MYPs provide can encourage a more performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, the occasional rate cases, an efficiency carryover mechanism, and/or careful ARM design.

Note also that customers can benefit from the more predictable rate growth that MYPs make possible. Rate trajectories can be sculpted to diminish rate bumps. Moreover, statistical benchmarking and productivity research are often used in plan design. These are useful complements to prudence reviews in ensuring that the rates utilities charge are commensurate with good operating performance.

Q. HOW CAN MYPS IMPROVE THE EFFICIENCY OF REGULATION?

A. Under MYPs, rate cases are less frequent and can be better planned and executed. Fewer costs need to be tracked. Terms of MYPs can be staggered so that rate cases overlap less. For example, rate cases for gas and electric services of Public Service could be scheduled to occur in different years. Streamlining the rate escalation chore can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues. Also, senior utility managers have more time to attend to their basic business of providing quality service cost-effectively.

Q. WHAT ARE SOME DISADVANTAGES OF MYPS?

A. MYPs are complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR over different issues such as the prudency of costs and the target rate of ROE. There are opportunities for strategic behavior that erodes potential plan benefits. However, best practices in the MYP approach to regulation have evolved to address such problems.

Q. PLEASE DISCUSS THE NEED FOR MYPS IN REGULATION OF ELECTRIC UTILITIES TODAY.

A. Benefits of MYPs tend to be greatest where traditional regulation is especially disadvantageous. These include situations where rate cases are frequent, many utilities must be regulated, marketing flexibility is especially desirable, and regulators have numerous complicated generic issues to ponder. Benefits of MYPs are also enhanced where they are especially easy to implement.

Q. DO ELECTRIC UTILITIES TODAY HAVE A PARTICULAR NEED FOR FREQUENT RATE CASES OR EXPANSIVE COST TRACKERS?

A. Yes. Figure MNL-D-2 above shows that key business conditions that cause electric utility attrition are considerably less favorable today on balance than they were in the decades before 1968 when COSR was becoming a tradition. Since the start of the Great Recession in 2008, declining residential and commercial UPC of electricity has been widespread. Large DSM programs have been a contributing factor. Increased penetration of customer-side DGS has also materially slowed UPC growth in some jurisdictions. Power use per residential customer of Public Service is trending downward by more than 1 percent annually.

The attrition challenge would be worse were it not for unusually slow price inflation since the Great Recession. However, inflation may be higher in the future due, for example, to faster growth in the world economy and tighter U.S. labor markets.

The need for frequent rate cases does vary among electric utilities. Differences in capex requirements is a major reason. In a period of sustained high capex, utilities need brisk escalation in rates when the capex does not automatically produce new revenue. For example, some electric utilities need sustained high capex to replace aging distribution assets. Technological change has created opportunities for advanced metering infrastructure and other "smart grid" capex that improves utility performance but may also not trigger much new revenue.[8]

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a utility distribution company ("UDC"). Furthermore, slow demand growth and requirements by state regulatory commissions for VIEUs to buy rather than build generation capacity that *is* needed is reducing VIEU capacity additions. On the other hand, some VIEUs are refurbishing or replacing old power plants and some need investments in emissions control equipment.

Q. YOU HAVE NOTED THAT DECLINING UPC IS A CHALLENGE FOR PUBLIC SERVICE. PLEASE DISCUSS THE ABILITY OF REVENUE DECOUPLING TO ADDRESS THIS PROBLEM.

A. Revenue decoupling adjusts a utility's rates periodically to help its *actual* revenue track its *allowed* revenue more closely. Many approved decoupling systems have two basic components: a revenue *decoupling* mechanism ("RDM") and a revenue

[8] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue, and adjusts rates to draw down these variances. Meanwhile, the RAM adjusts allowed revenue between rate cases to reflect changing cost pressures. The cost of utilities tends to rise for various reasons that include input price inflation and growth in operating scale. The RAM therefore typically escalates allowed revenue. These mechanisms thus address different sources of financial attrition utilities experience between rate cases. The RDM addresses *revenue*-related attrition, while the RAM addresses *cost*-related attrition. Other decoupling systems escalate allowed revenue via special RDM provisions.

In the absence of automatic revenue requirement escalation, decoupled revenue may not grow between rate cases and to that extent cannot help finance cost growth. For this reason, most approved decoupling systems have some form of revenue escalation. Utilities operating with an RDM but no form of automatic revenue escalation often file frequent rate cases. When developing a decoupling system, the *need* for an automatic revenue escalation mechanism is thus less of an issue than its *design*.

Most decoupling systems of U.S. energy utilities escalate allowed revenue only for retail customer growth.[9] I noted above that the number of customers is an important driver of cost in its own right and is highly correlated with other scale-related cost drivers like peak demand. The number of customers has

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

frequently been the most important scale variable in PEG's econometric studies of electric utility cost. My econometric work for Public Service in this proceeding found that 1 percent growth in the number of customers typically raised non-fuel O&M expenses of sampled VIEUs by about 0.55 percent in the long run. Meanwhile, growth in generation volume and capacity raised these expenses by 0.12 percent and 0.18 percent respectively. Escalating revenue for customer growth reduces the need for rate cases but rarely eliminates it because cost has several other drivers. Utilities operating under revenue per customer RAMs therefore rarely agree to rate case moratoriums.

Some approved RAMs for gas and electric utilities have been “broad based” in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. Broad-based RAMs can reduce the need for rate cases substantially and thereby serve as the attrition relief mechanism for an MYP.

Q. DOES THIS DISCUSSION HAVE IMPLICATIONS FOR PUBLIC SERVICE?

A. Yes. This Commission recently approved a pilot revenue decoupling mechanism for the Company’s residential and small commercial electric services. The Commission rejected the Company’s proposal for an RDM that would effectively escalate allowed residential and small commercial base revenue each year by growth in the number of customers served. The Company will benefit only from growth in customer and line extension charges. However, no part of the contribution new customers make to fixed costs through their volumetric charges will be available to Public Service to help it finance growth in its fixed costs. There is no compensation for the declining UPC of additional customers, even though managing the demand of these customers is a key to containing load-related costs. The customer's benefit from decoupling is actually negative if the number of customers is growing faster than use per customer is declining. The Commission's rationale for rejecting escalation of allowed revenue for customer growth is that the added revenue might overcompensate Pubic Service for its fixed costs.

Q. WHAT IS YOUR VIEW OF THIS DECISION?

A. This decision is unfortunate for several reasons. Public Service expects customer growth in the next few years that is fairly brisk by today's standards. Growth in demand will also affect other dimensions of its operating scale. Since customer growth is highly correlated with growth in peak demand and other scale variables, escalation of revenue for customer growth can effectively compensate a utility for growth in other dimensions of operating scale as well. In the absence of an MYP, I am therefore concerned that the approved Revenue Decoupling Adjustment would deny Public Service the revenue growth needed to fund growth in its scale.

Even if escalating revenue for customer growth did overcompensate the Company a little for growth in its scale, that is not in my view a problem. Growth in fixed cost (defined as cost that is insensitive to fluctuations in system use) is not solely driven by growth in scale. The additional cost drivers include input price inflation and increased undergrounding requirements. Because of these other cost drivers, escalation for customer growth is very unlikely to produce overearnings, as I demonstrate later in my testimony.

There is no principle in utility regulation that growth in revenue between rate cases should solely compensate utilities for growth in their operating scale. In fact, I showed I Figure MNL-D-2 that until the Great Recession, growth in residential and commercial UPC of electric utilities was positive so that revenue growth between rate cases *exceeded* customer growth. This helped utilities finance other sources of cost growth and reduced the frequency of rate cases. In the years before 1968 when growth in UPC was quite rapid, I have shown that rate cases were infrequent, lowering regulatory cost and strengthening performance incentives. Utility productivity growth was rapid.

Note, finally, that a revenue decoupling mechanism is designed to weaken the incentive for the utility to resist DSM and DGS. Decoupling does not achieve this by fully compensating the utility for the base rate revenue it loses due to DSM and DGS. Instead, it achieves it by making revenue insensitive to system use. A utility could reasonably request compensation for all revenue lost due to DSM and DGS. In fact, some utilities have lost revenue adjustment mechanisms ("LRAMs") that accomplish this. Lost revenue depends on growth in delivery volumes that would occur in the absence of DSM and DGS. Customer growth may be equal or even less than this hypothetical billing determinant growth.

My analysis points to the conclusion that escalation of allowed revenue for customer growth by some means is just and reasonable when a utility has revenue decoupling. This is tantamount to giving the utility the revenue growth it would receive were UPC static. The great majority of revenue decoupling systems for U.S. gas and electric utilities are either based on use (or revenue) per customer or include a separate RAM that escalates allowed revenue for customer growth. In the absence of such provisions, revenue growth between rate cases may not be sufficient to fund growth in operating scale. This strengthens the Public Service's argument for a new MYP using a FTY.

Q. RETURNING TO YOUR ANALYSIS OF REASONS TO ADOPT MYPS, IS THE NUMBER OF ELECTRIC UTILITIES THAT MUST BE REGULATED A PROBLEM?

A. Not in the United States. Many states, including Colorado, don't regulate many electric utilities. However, states must also typically regulate some natural gas, telecommunications, and water utilities and some ground transportation (e.g., taxi and limo) businesses.[10] Thus, streamlined regulation of electric utilities is always welcomed. Note also that mergers and acquisitions over the years have caused the number of utilities owned by some companies to rise. Companies which own multiple utilities have a legitimate interest in adopting more efficient approaches

[10] In contrast, regulation outside the United States is often conducted at the national level.

to regulation like MYPs. Xcel Energy currently provides retail utility services in portions of eight states.

Q. CAN MYPS ENCOURAGE UTILITIES TO EMBRACE EFFICIENT DSM AND DGS?

A. Yes. I have already noted that provisions can be added to MYPs which strengthen a utility's incentive to embrace DSM and DGS. In addition MYPs can, by strengthening general incentives to contain cost, provide their own incentive for utilities to use DSM and DGS to contain load-related costs of base rate inputs. A utility might, for example, be more incentivized to use DSM and well-sited customer-side DGS to delay a costly distribution system upgrade. Time of use pricing is encouraged since this can help contain load-related costs. Note also that MYPs strengthen incentives to embrace DSM and DGS without requiring complicated load or cost savings calculations. The combination of an MYP, revenue decoupling and/or an LRAM, demand-side management PIMs, and the tracking of DSM-related costs can thus provide four "legs" for the DSM "stool."[11]

Q. ARE THERE ALTERNATIVE USES FOR REGULATORY RESOURCES ENGAGED IN RATE CASES TODAY?

A. Very much so. Regulatory resources that are currently devoted to electric rate cases have many alternative uses in this era of rapid change. Among the areas

---

[11] A *three*-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in Dan York and Martin Kushler, "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," ACEEE, September 2011.

where thoughtful review is currently needed are distribution system planning, rate design, and compensation to DGS customers for their services. Colorado has more than its share of these issues given the competitiveness of renewable resources today and public interest in green energy.

Q. DO SOME ELECTRIC UTILITIES NEED MARKETING FLEXIBILITY?

A. Yes. Marketing flexibility is increasingly useful for electric utilities. There is growing interest in green power packages and in miscellaneous new services that may be enabled by "smart grid" technologies. Greater reliance on intermittent renewable resources for power has increased the need for time-sensitive rates. These resources loom large in the future supply plan of Public Service.

Note also that vertically integrated electric utilities like Public Service generally have greater need for marketing flexibility than UDCs. One reason is that the large-load customers whose demand has traditionally been most sensitive to the terms of service make a much larger contribution to a VIEU's base rate revenue. Another reason is that VIEUs may benefit more from offering green power and electric vehicle service options since they may provide some of the power from company-owned generation. Time-sensitive pricing can contain generation costs as well as transmission and distribution costs.

Q. ARE THERE CONCERNS ABOUT THE STABILITY OF THE ELECTRIC UTILITY INDUSTRY TODAY?

A. Yes. I noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises questions about the ability of electric utilities to cope with increased DSM and DGS. If utility performance incentives are weak, performance can deteriorate despite mounting competition. Utilities may, for example, choose such a time for high replacement capex.

The end result can be higher rates that further discourage use of grid services. This is a source of potential instability in the electric utility industry that is more worrisome where the competitive threat from DGS is large. I have discussed above a prior episode when utility industry productivity growth slowed under challenging business conditions. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut costs.

Q. ARE SOME CHANGES IN MYP DESIGNS NEEDED TO ACCOMMODATE EMERGING BUSINESS CONDITIONS?

A. Yes. I have already mentioned the desirability of including revenue decoupling and conservation PIMs in MYPs today. In addition, regulators and many stakeholders are concerned today that utilities increase the effectiveness of peak load management as they rely more on renewable sources of power. Regulators in jurisdictions where MYPs are standard practice have taken the lead in developing new PIMs for their plans which address emerging concerns and challenges. For example, regulators in New York and California have added PIMs or other incentives to MYPs to reward utilities for peak load management and/or embrace of miscellaneous non-wire alternatives to local investments in the grid. Performance metric systems are expanding to address other new dimensions of performance like the quality of service to DGS customers and the utilization of smart grid capabilities. The “RIIO” approach to energy utility regulation in Britain has garnered considerable attention from U.S. regulators. This approach features MYPs with extensive performance metric systems.

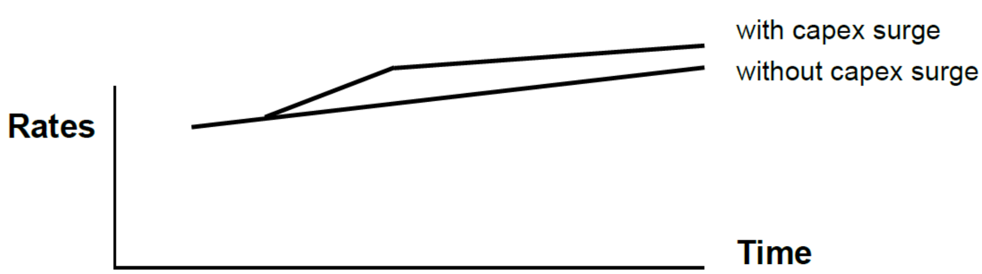
Q. PLEASE DISCUSS THE DIFFICULTY OF MYP IMPLEMENTATION.

A. The difficulty of implementing MYPs has changed over time and varies considerably among utilities. The biggest challenge is usually identification of a reasonable ARM. Implementation of indexed ARMs has traditionally been easier for UDCs than for vertically integrated utilities. The cost of UDC base rate inputs tends to grow gradually and predictably as the economies that UDCs serve gradually expand. In contrast, VIEUs have in the past had “stair step” cost trajectories with large rate increases when solid-fuel power plants came into service alternating with periods of slow cost growth as the new units depreciated. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays.

Today, many UDCs are proposing accelerated grid modernization programs involving several years of high capex. The need for these programs can be difficult for regulators to judge in an era of rapid technical change and shifting demand for electric utility services. VIEUs, meanwhile, are experiencing *more gradual* cost growth than in the past since fewer generation capacity additions are needed and capacity that *is* built tends to be more modular natural gas-fired or wind-powered units. Depreciation of older generation plant meanwhile slows rate base growth. However, some VIEUs are building new, cleaner generating facilities (including emissions control equipment) or modernizing older generation plants. Aging generating capacity can have rising operating costs.

Figures MNL-D-5 and MNL-D-6 illustrate the changing needs for rate escalation for UDCs and VIEUs. They suggest that it has become easier over time to develop ARMs for VIEUs and more difficult to develop ARMs for UDCs. This helps to explain why use of MYPs has recently grown more rapidly in VIEU regulation.

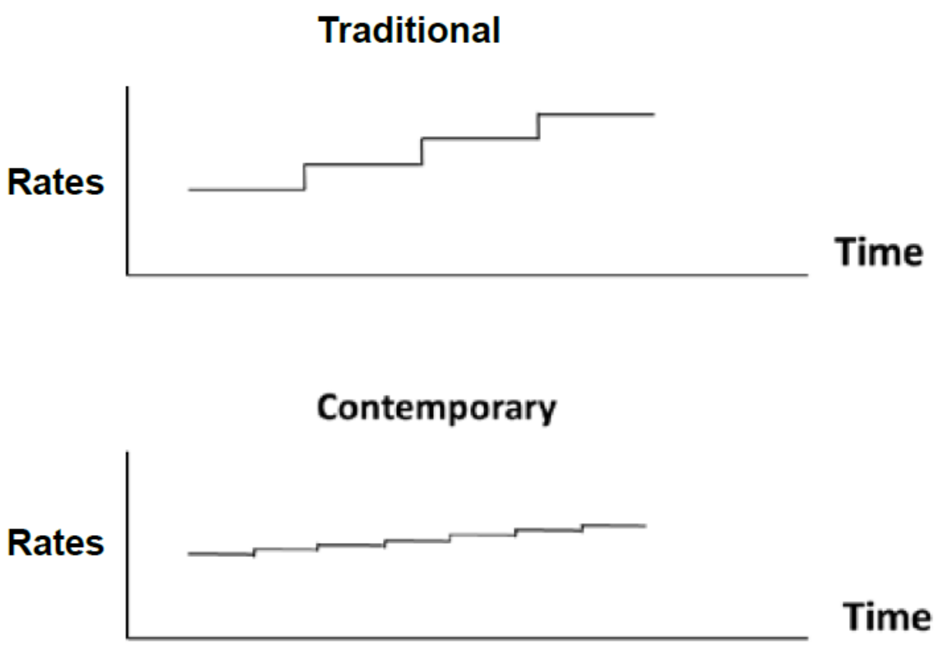
Figure MNL-D-5 Rate Escalation Requirements for UDCs. Capex surges can accelerate the normally gradual escalation of UDC rates.



Consider also that jurisdictions vary in their regulatory traditions and human capital (the experience and the expertise of regulatory practitioners).

Generally speaking, adoption of MYPs is easier for jurisdictions that have experience with the use of forward test years in rate cases. Colorado's Commission has not used FTYs but does have experience in the design of MYPs.

Figure MNL-D-6 Rate Escalation Requirements for VIEUs. Rate escalation requirements of VIEUs are becoming more gradual.



D. <u>Precedents for MYPs in Other Jurisdictions</u>

Q. ARE THERE MANY PRECEDENTS FOR USE OF MYPS?

A. Yes. MYPs have been used to regulate U.S. utilities since the 1980s. They were first used on a large scale for railroads and telecommunication carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated continuation of COSR. MYPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. Both industries achieved rapid productivity growth under MYPs. US West and its successor, Qwest, have operated under MYPs in Colorado.[12] Some states still use MYPs to regulate incumbent local exchange carriers.[13] The Federal Energy Regulation Commission ("FERC") uses MYPs to regulate oil pipelines.[14]

MYPs have also been used to regulate gas and electric utilities.[15] California's commission has required use of MYPs since the 1980s. MYPs became popular in several northeastern states in the 1990s. In addition to MYPs, several states established extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also been part of the ratemaking treatment for many mergers and acquisitions.

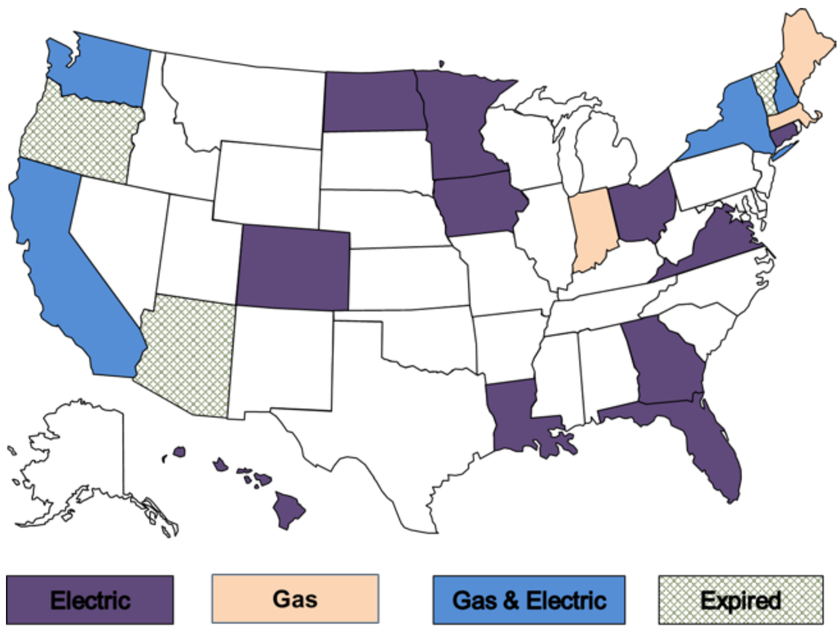
Q. HOW MANY STATES CURRENTLY HAVE MYPS FOR ENERGY UTILITIES?

A. Figure MNL-D-7 shows states that currently use MYPs to regulate retail services of U.S. gas and electric utilities. It can be seen that MYPs are a common form of alternative regulation. Use of MYPs has recently spread to VIEUs in such diverse states as Arizona, Florida, Virginia, and Washington. This Commission has twice

---

12 Colorado Public Utilities Commission, Decision No. C99-222 in Docket Nos. 97A-540T and 90A-665T, March 1999 and Decision No. C05-0802 in Docket Nos. 04A-411T and 04D-440T, June 2005.
13 See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.
14 See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.
15 MYP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The latest is Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

Figure MNL-D-7 MYPs in the U.S.



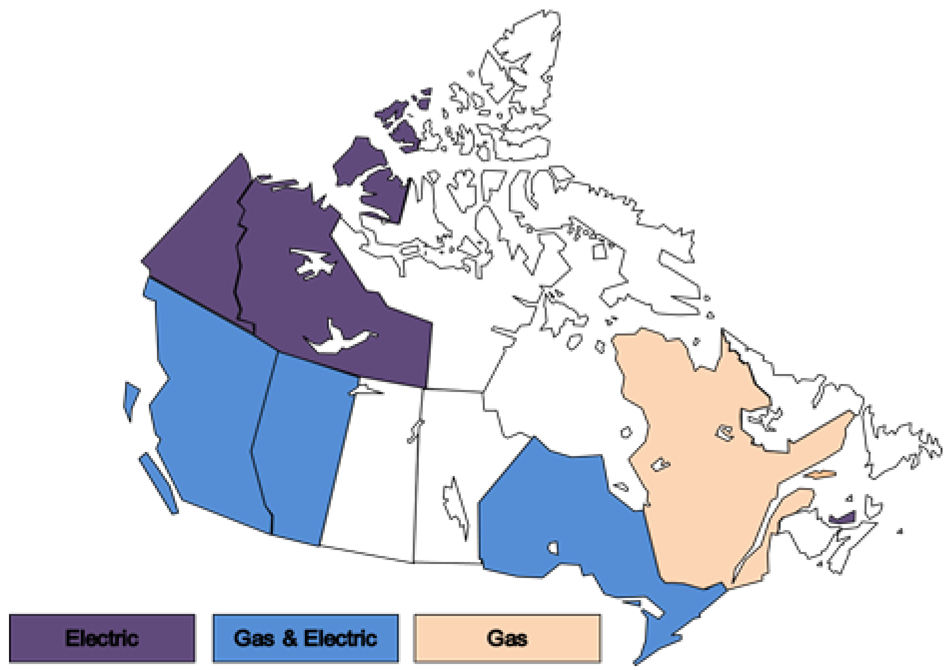
approved MYPs for the Company's electric services.[16] An MYP was recently approved in Minnesota for electric services of an affiliated company, Northern States Power Company. In addition, several states have recently experimented with "mini" MYPs involving only two plan years.

Q. ARE MYPS USED OUTSIDE THE U.S.?

A. Yes. Figure MNL-D-8 shows that MYPs are widely used to regulate Canadian energy utilities. Overseas, MYPs are the norm in Australia, Ireland, New Zealand, and the United Kingdom. Countries in continental Europe that use MYPs include

[16] Public Utilities Commission of Colorado, Decision C12-0494, Docket No. 11AL-947E, April 2012 and Decision C15-0292, Docket No. 14AL-0660E, February 2015.

Figure MNL-D-8 MYPs in Canada.



Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MYPs are also common in Latin America.

Q. DOES THE IMPETUS FOR MYPS ALWAYS COME FROM UTILITIES?

A. No. Use of MYPs in some American states has been driven by Commissions or lawmakers. In other countries, impetus for MYPs has come from the public sector even more frequently. For example, provincial law in Quebec requires the Régie de l'Energie to use approaches to regulation for Hydro-Québec, the large electric utility in the province, which streamline regulation, encourage performance gains, and share benefits with customers.[17] The Régie recently ordered Hydro-Québec to operate prospectively under an MYP for its power distributor services. Utilities in some jurisdictions have mounted legal challenges to MYPs that regulators have chosen.

Q. HAVE REGULATORS BASED THEIR APPROVAL OF MYPS ON AN ANALYSIS LIKE THE ONE YOU HAVE MADE IN THIS TESTIMONY?

A. Yes. For example, Washington's Utility and Transportation Commission stated the following in recently approving MYPs for both the gas and electric services of Puget Sound Energy:

> The rate plan provides a degree of relative rate stability, or at least predictability, for customers for several years. The rate plan is an innovative approach that will provide incentives to PSE to cut costs in order to earn its authorized rate of return. Moreover, the lack of annual rate filings will provide the Company, Staff, and other participants in PSE's general rate proceedings with a respite from the burdens and costs of the current pattern of almost continuous rate cases with one general rate case filing following quickly after the resolution of another.[18]
>
> We are satisfied on the basis of the record that our approval of the rate plan strikes a reasonable balance and will result in rates that are fair to customers and the company, leaving PSE with an improved opportunity to earn its authorized return while protecting customers by requiring PSE to improve the efficiency of its operations thus building savings that, over the long term, will keep rates lower than they otherwise might be.[19]

---

[17] National Assembly of Québec, 40th legislature, 1st session, Bill n°25 (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed June 2013.
[18] Washington Utilities and Transportation Commission's Order 07 in Dockets UE-121697, UG-121705, UE-130137, and UG-130138, June 2013, p. 66.
[19] *Ibid*., p 75.

The Commission here in Colorado stated the following in approving the first MYP for electric services of the Company:

> The fact that the Settlement Agreement results in certainty regarding Public Service's non-energy electric rates is an important aspect of the Settlement Agreement. Certainty over rates assists the residential customers in budgeting for future rate changes. Likewise, it is advantageous for the commercial and industrial customers. This allows existing businesses to plan their future utility costs with more certainty. It also provides new business in Public Service's Colorado territory with information regarding not only current commercial electric rates, but also where those rates will be over the next two years. . .
>
> The multi-year aspect of the Settlement Agreement is another commendable aspect with respect to regulatory filings. Given that inflation and interest rates are low and stable, the Settlement Agreement takes advantage of that environment. Annual filings by utilities are not as needed or as productive during such economic times. This should result in lower regulatory expenses for both Public Service and the stakeholder groups concerned about electric rates. The "stay-out" provision should also provide incentive for Public Service to strive for efficiency.[20]

Q. HAVE STUDIES BEEN DONE WHICH EXPLORE PLAN DESIGN ISSUES AND CONSIDER MYP EXPERIENCE?

A. Yes. I have authored or co-authored several papers on MYP design.[21] My new paper for Lawrence Berkeley National Laboratory discusses the rationale for MYPs and plan design challenges and presents six case studies. The productivity growth of utilities operating under MYPs (and, more generally, infrequent rate cases) is compared to norms for a larger sample. I also present

---

[20] Public Utilities Commission of Colorado, Decision C12-0494, Docket No. 11AL-947E, April 2012, pp. 22-23.

[21] See, for example, M. Lowry and L. Kaufmann, "Performance-Based Regulation of Utilities," *Energy Law Journal*, October 2002. Other notable treatises on MYPs include G.A. Comnes, S. Stoft, N. Greene, and L.J. Hill, "Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues," Berkeley Lab, November 1995.

results of a numerical analysis designed to gauge the incentive power of alternative regulatory systems. The study found that MYPs and extended rate stayouts generally improve utility performance.

The case study of Central Maine Power ("CMP"), Maine's largest electric utility, is illustrative. MYPs were encouraged there by the Maine Public Utilities Commission when it was led by Thomas Welch, a former telecommunications industry lawyer. In a 1993 rate case decision, Maine's commission encouraged CMP to operate under an MYP when it was still a vertically integrated electric utility like Public Service. This decision took into consideration CMP's then-recent history of rapid rate escalation and losses of margins from large-volume customers. The commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[22] Maine's commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers;

[22] Maine Public Utilities Commission, Order dated December 14, 1993, Docket No., 92-345, pp. 14-15.

> and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[23]

The commission outlined its views of potential costs and benefits of MYPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[24]

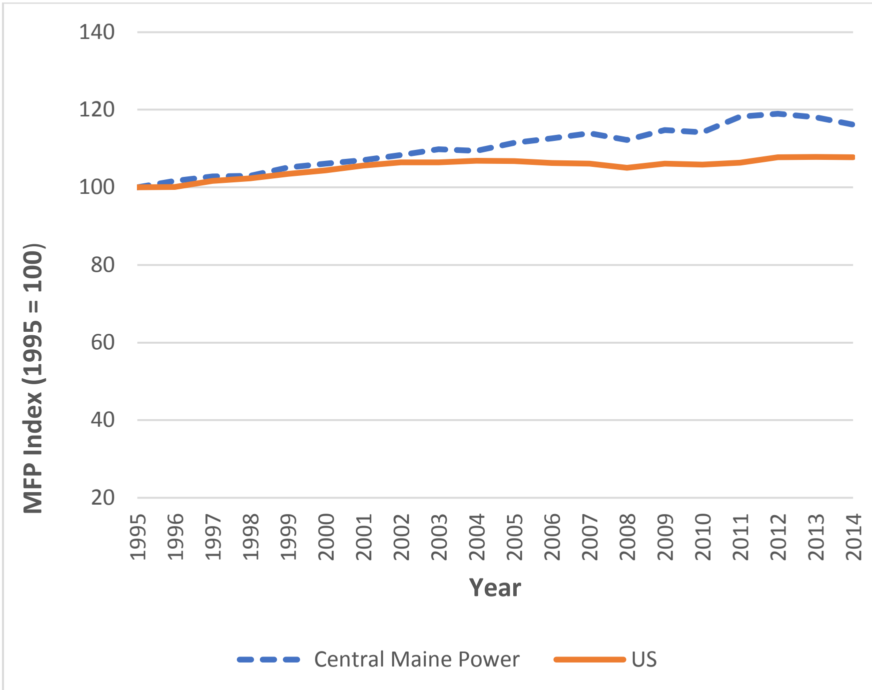
Q. WHAT WAS CMP'S EXPERIENCE OPERATING UNDER MYPS?

A. CMP operated under three successive "alternative rate plans" from 1995 to 2013. The company exited the generation business during the first plan. Full rate cases did not occur between the plans. We found that CMP achieved productivity growth in the provision of distributor services which was well above the national norm, as shown in Figure MNL-D-9. CMP's success in containing capital spending during these years is especially notable.

---

[23] Maine Public Utilities Commission, *op. cit.*, p. 126.
[24] Maine Public Utilities Commission, *op. cit.,* p. 130.

Figure MNL-D-9 CMP's Distributor Productivity Growth Under MYPs



Source: Mark Newton Lowry, Matthew Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 2017, Lawrence Berkeley National Laboratory, p. 6.5.

III. KEY ISSUES IN MYP DESIGN

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I would like to discuss in more detail some key issues in MYP design. I focus on ARMs, earnings sharing, and efficiency carryover mechanisms.

A. ARMs

Q. PLEASE DISCUSS THE DESIGN OF THE ARM IN A MULTIYEAR RATE PLAN.

A. Four well-established approaches to ARM design can, with sensible modifications, be used to escalate rates or allowed revenue: indexing, forecasting, hybrid approaches, and the tracker/freeze approach.

Q. WHAT IS THE INDEX APPROACH TO ARM DESIGN?

A. An indexed ARM is developed using indexes and other statistical research on cost trends in the utility industry. Cost theory reveals that the growth of cost can be decomposed into the inflation in an input price index less the growth in a productivity index plus the growth in a scale index.

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Scale}. \quad [2]$$

This result has provided the basis for revenue cap indexes of general form

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Scale} + Y + Z. \quad [3]$$

The number of customers served by the utility is typically used as the scale index in these formulas. A more sophisticated scale index might summarize trends in several scale variables. The inflation measure can be a custom index of utility input price inflation, but macroeconomic inflation measures like the GDPPI are also used. Some indexed ARMs have escalated allowed revenue only for inflation on the premise that the cost impacts of growth in productivity and operating scale are offsetting.

The X variable in the ARM formula, which is sometimes called the productivity factor or "X factor," often reflects the average historical trend in the productivity of a group of peer utilities. A stretch factor (sometimes called a consumer dividend) is then added to X to guarantee customers a share of the benefit of productivity growth if it is expected to exceed the peer group norm due, for example, to the stronger performance incentives expected under the plan. Stretch factors are sometimes based in whole or in part on statistical benchmarking studies on the premise that historically poor (good) cost performers are capable of more rapid (slower) productivity growth.

Q. WHAT ARE SOME PROS AND CONS OF INDEXED ARMS?

A. Indexed ARMs compensate utilities automatically for important external business conditions that drive cost growth. Rate growth is typically gradual. Escalation can be based on actual inflation and customer growth rather than forecasts. This provides timely attrition relief that reduces operating risk without weakening performance incentives. Controversies over cost forecasts can be avoided. Between rate cases, customers can be guaranteed benefits of productivity growth that equals or, with a stretch factor, exceeds industry norms.

On the other hand, indexed ARMs typically reflect long-run productivity trends. They may therefore undercompensate utilities if their capex is surging. Cost trackers may then be needed to address capital revenue shortfalls. Design of indexed ARMs that apply to capital as well as O&M cost involves statistical cost research that can be complex and controversial.

Q. ARE THERE PRECEDENTS FOR INDEXED ARMS?

A. Yes. In the United States, indexed ARMs have been extensively used to regulate railroads, telecommunications carriers, and oil pipelines. A price cap index was used in an MYP of Qwest in Colorado. Indexed ARMs have been used to regulate gas and electric utilities in California and New England. Indexed ARMs have also been used several times by regulators in Canada and New Zealand to regulate energy utilities.

Q. WHAT IS THE FORECAST APPROACH TO ARM DESIGN?

A. A forecasted ARM is based on multi-year cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019, and 3 percent in 2020). The trend in the cost of *existing* plant is relatively straightforward to forecast since it depends mechanistically on depreciation. The focus of a proceeding to approve a capital cost forecast is instead on the value of plant *additions* during the plan.

Advantages of forecasted ARMs include their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Rate trajectories can be still be smoothed to reduce rate “bumps.” In considering multi-year cost forecasts, the commission and customer organizations have an opportunity to weigh in on the utility’s business plan. Some forecasted ARMs do not adjust rates during the plan if the actual cost a utility incurs differs from the forecast. This ARM design approach can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

On the downside, forecasted ARMs do not protect utilities from unforeseen and unusual growth of input prices and operating scale. It can be difficult for regulators to identify just and reasonable multiyear cost forecasts. For example, it can be difficult to ascertain the value to customers in a given cost forecast.

Q. IS THERE PRECEDENT FOR USE OF FORECASTED ARMS?

A. Yes. Forecasted ARMs have been routinely used in New York MYPs. Other U.S. jurisdictions that have used forecasted ARMs include California, Connecticut, Georgia, and Washington. Outside the U.S., forecasted ARMs have long been used in Australia and Britain and are sometimes used in Canada.

Q. HOW HAVE REGULATORS REDUCED CONCERN ABOUT COST FORECASTS FOR THIS KIND OF ARM?

A. The Ontario Energy Board asks utilities to substantiate forecasted ARMs with productivity and cost benchmarking research. The Board, additionally, requires power distributors to use econometric benchmarking to appraise their proposed revenue requirements in forward test year rate cases. Regulators in Britain and

Australia have commissioned their own engineering as well as benchmarking research with hopes of developing an independent view on needed cost escalation.

Q. PLEASE DISCUSS THE HYBRID APPROACH TO ARM DESIGN.

A. "Hybrid" approaches to ARM design use a mix of escalation methods. The most popular hybrid approach in the U.S. involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs.[25] O&M revenue is indexed. Meanwhile, capital revenue is based on other methods that often involve forecasts.

Indexing O&M revenue reduces the risk of unexpectedly high and low inflation and limits the need to file and review forecasting evidence. Rate escalation is typically gradual. Good data on O&M input price trends of gas and electric utilities are available in the U.S. These include Bureau of Labor Statistics labor cost indexes and Global Insight's indexes of prices for M&S inputs that energy utilities use.

Indexed O&M revenue requirement escalators have been used for many years by gas and electric utilities in Vermont.[26] They have also been used in rate cases with forward test years. For example, in California it is common to index O&M revenue in rate cases for input price inflation.

[25] A "hybrid" designation can in principle be applied to other ARM design methods, including the method used in Great Britain.
[26] Capital cost is subject to COSR in these Vermont plans. Hence, I do not consider them to be MYPs.

The forecast approach to capital revenue, meanwhile, accommodates diverse capital cost trajectories. Revenue growth can nevertheless be smoothed. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the downside, forecasts of plant additions are still required and these can be controversial.

A variant on O&M revenue indexing is to fix O&M revenue escalation *in advance* but base it on index formulas. This approach has been used several times in California and Australia. A variant on capital cost forecasting is to update the capital revenue forecast when new information on capital prices (e.g., construction cost indexes and/or the rate of return on capital) becomes known.

Note also that shortcuts are sometimes taken in preparing capital revenue requirements. For example, the budget for plant additions is sometimes set for several years at the utility's average value in recent years, or at the value for the test year of the rate case. Both of these options have been used in California.

Q. ARE THERE PRECEDENTS FOR HYBRID ARMS?

A. Yes. Hybrid ARMs have been used many times in California since the 1980s. They are currently used in MYPs of Southern California Edison and the Hawaiian Electric companies.

Q. WHAT IS THE "TRACKER/FREEZE" APPROACH TO ARM DESIGN?

A. Some MYPs feature a rate freeze in which the ARM provides no base rate escalation during the plan. This is sometimes combined with one or more trackers for rapidly growing costs. Under this approach, the cost of generation plant additions is often tracked.

The tracker/freeze approach to ARM design has recently been used in MYPs for several U.S. VIEUs. An example is the current plan for the Company's electric services. Other VIEUs that have operated under tracker/freeze mechanisms include Arizona Public Service, Cleco Power, Florida Power and Light, and Virginia Electric and Power.

B. Earnings Sharing

Q. PLEASE DISCUSS THE EARNINGS SHARING PROVISIONS OF MYPS.

A. ESMs share earnings variances that arise when a utility's ROE deviates from the commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there is often a "dead band" in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band, there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[27] While most ESMs share both surplus and deficit earnings, some share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Advantages of ESMs include reduced risk of undesirable earnings outcomes. Unusually high or low earnings may be undesirable insofar as they

---

[27] An ESM is therefore sometimes referred to as a "banded ROE."

reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases. These advantages of ESMs help to explain why they have been used in MYPs for the Company's electric services.

On the downside, ESMs weaken utility performance incentives. Marketing flexibility can be complicated by an ESM because discounts and other special terms of service that are offered to some customers can affect earnings variances that are shared with all customers.[28] ESM filings can be controversial. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures like inflation and customer indexing, Z factors, or revenue decoupling.

Whether or not to add earnings sharing to an MYP is one of the more difficult decisions in MYP design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of the current U.S. and Canadian MYPs.

[28] This problem can be contained by sharing only the utility's earnings surpluses.

C. Efficiency Carryover Mechanism

Q. HOW DOES AN EFFICIENCY CARRYOVER MECHANISM WORK?

A. An ECM permits a utility to "carry over" to future plans a portion of the lasting performance gains that it achieves. This rewards the utility for achieving long-term performance gains and helps ensure that customers benefit from plans. Our research suggests that the incentive benefits of ECMs can be substantial, especially in MYPs with shorter terms.

A well-designed ECM focuses on the value to customers of the revenue requirement in the next plan. The focus is often on the revenue requirement for the test year in the rate case that establishes rates for the first year of the next plan. Performance can be measured by comparing this revenue requirement to a benchmark. The benchmark can be based on statistical benchmarking or the ARM from the expiring MYP.[29]

Q. ARE THERE PRECEDENTS FOR ECMS?

A. Yes, ECMs have been approved in several U.S. jurisdictions (e.g., Massachusetts, Missouri, and New York) and are currently used in Alberta and Australia. The Ontario Energy Board uses an econometric benchmarking model to appraise the total costs of most provincial power distributors in every year of their MYPs. My company developed the model and annually updates the study. Superior cost performers are assigned lower X factors in their price cap indexes.

---

[29] In the latter case, the ARM may need to be extended hypothetically to benchmark the revenue requirement for a forward test year.

Sustainable cost reductions achieved in one plan can therefore produce higher earnings in future plans.

IV. AN APPRAISAL OF THE COMPANYS MYP PROPOSAL

Q. PLEASE DESCRIBE THE MYP WHICH PUBLIC SERVICE IS PROPOSING FOR ITS ELECTRIC OPERATIONS.

A. Key provisions of the Company's proposed plan are summarized in Figure MNL-D-10. The plan would establish terms of service for the four calendar years 2018 through 2021. The revenue requirements would be determined by hybrid methods. Escalation of capital revenue would be based on a conventional cost forecast with possible adjustments for changes in utility bond yields in years 2-4 of the MYP term. Expenses for Advanced Grid Intelligence and Security would also be forecasted. Escalation of revenue for other labor O&M expenses would be escalated by 3 percent in the 2016 HTY to account for expected wage increases in 2017 and then escalated by 2 percent in each of the 2018, 2019, 2020 and 2021 Forward Test Years. Revenue for other non-labor (e.g., material and service) O&M expenses would be held flat with the 2016 HTY. The plan would also include an ESM called an Earnings Test.

Tracker treatment is proposed for some cost categories.

- Power supply and transmission by others
- DSM
- Pension benefits
- Transmission capital

Figure MNL-D-10 Summary of the Proposed Electric MYP

Basic Approach to Incentive Regulation	Multiyear Rate Plan
Revenue or Rate Escalation	Revenue Escalation
Relaxing the Revenue/Usage Link	Revenue Decoupling for Residential and Small Commercial Customers
Attrition Relief Mechanism	Hybrid
Y Factors	Power Supply Upstream Transmission Property Taxes Pension Benefits
Z Factors	Yes
Performance Incentive Mechanisms	Reliability Safety Customer Service Demand-Side Management Off-System Energy Transactions
Earnings Sharing Mechanism	Yes
Marketing Flexibility	Yes
Plan Term	4 Years

However, the Clean Air Clean Jobs Act ("CACJA") rider would be eliminated. Costs of property taxes, the costs of Mountain West Transmission Group, including joining a regional transmission organization, and of potential early retirement Comanche Units 1 and 2 as part of the Colorado Energy Plan would be deferred by creating regulatory assets. Z factor treatment is proposed for changes in generally-accepted accounting principles, tax laws, and federal, state, and municipal laws and regulations, natural disasters, and major acquisitions or divestitures.

The following provisions, which are occasionally found in approved MYPs, are already part of the regulatory system the Commission has approved for the Company's electric services and would continue:

- A performance metric system called the Quality of Service Plan ("QSP") has been in place for many years to aid regulation of electric service quality. There are PIMs for reliability and several aspects of the Company's customer service quality. Revenue decoupling was recently approved for the Company's residential services.
- The Company has some flexibility in the marketing of electric services. The Flexible Pricing Policy is sanctioned by Colorado statue.[30]
- There are various initiatives underway to assist low-income customers.

Q. PLEASE PROVIDE A QUALITATIVE APPRAISAL OF THE PROPOSAL

A. All of the key provisions of a typical MYP have been addressed in the Company's proposal. The particular package of provisions Public Service is proposing is unique, as in any plan, but lies in the mainstream of MYPs used today. There is no efficiency carryover mechanism, but these are not yet the norm in MYP design.

---

[30] See Colorado Revised Statutes, Section 40-3-104.3.

The general approach to ARM design proposed by Public Service is widely used. Rate growth is smoothed. Public Service has demonstrated the value of its proposed revenue requirements by filing extensive in-house evidence and by commissioning the benchmarking and indexing work I am presenting in this testimony. Supportive statistical research for proposed revenue requirements is rarely initiated by North American utilities. The Company's decision to sponsor such work reflects its dedication to offering customers good value.

Some plans do not have ESMs, but these mechanisms are also common in first generation plans. The Earnings Test that Public Service proposes asymmetrically shares *surplus* earnings but not earnings *shortfalls*. Placing the Company at risk for earnings shortfalls protects customers, strengthens performance incentives, and facilitates marketing flexibility. In addition, many ESMs have a deadband in which the utility keeps 100 percent of small earnings surpluses. Public Service proposes instead that customers have a share in *all* earnings surpluses. All earnings exceeding 12 percent would be returned to customers. The strong customer protection provided by the Earnings Test should further reduce concern that the proposed revenue requirements are too high.

The four-year period of the proposed plan is common. The MYPs the Commission has previously approved for the Company's electric services have had three-year terms.

DSM will be encouraged by a performance incentive mechanism, revenue decoupling for residential and small commercial customers, and the tracking of the Company's DSM expenses. Decoupling removes disincentives for Public Service to embrace customer-side DGS and a wide range of DSM initiatives.

V. REASONABLENESS OF THE COMPANY'S PROPOSED REVENUE REQUIREMENTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I will discuss in this section the statistical benchmarking and index research that PEG has undertaken to assess the reasonableness of the Company's proposed revenue requirements.

A. Benchmarking Research

Q. WHAT IS STATISTICAL BENCHMARKING AND HOW IS IT USEFUL IN A RATE CASE?

A. The efficiency implicit in the Company's proposed revenue requirement is an important consideration for the Commission in determining the merit of the plan. Statistical cost benchmarking can be used to appraise proposed revenue requirements. Historical data on utility operations are used to establish benchmarks that can be used in quantitative cost performance appraisals. These data are available from reports utilities file with governmental agencies.

Accurate benchmarking is still challenging since variations in the costs of utilities are attributable as much or more to differences in the local business conditions they face as they are to differences in their efficiency. A cost benchmark for a particular utility should therefore reflect the performance that might be expected given that utility's local business conditions. Statistical cost research can identify important cost drivers, and this information can be used to establish better benchmarks and draw the right conclusions about cost management.

Q. PLEASE EXPLAIN HOW YOU USED BENCHMARKING TO ASSESS THE REASONABLENESS OF PUBLIC SERVICE'S PROPOSED REVENUE REQUIREMENTS.

A. We addressed the reasonableness of the Company's proposed non-fuel O&M revenue requirements during the plan using two statistical benchmarking methods: econometric modelling and unit cost indexing. Some cost categories were excluded from the benchmarking because they are slated for tracking treatment in the MYP, unusually volatile, difficult to benchmark well, and/or are substantially beyond utility control. The excluded costs included expenses for power supply and transmission by others, customer service and information, pensions and benefits, and uncollectible bills.

Data used in the study were drawn from respected sources. The cost data were chiefly drawn from FERC Form 1. A uniform system of accounts has been established for this form.

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

A. O&M expenses are often the largest component of cost a utility can control in the short run. They are also one of the biggest sources of uncertainty regarding revenue requirement projections. An analogous study of the proposed revenue requirements for *total* non-fuel cost is complicated today by the numerous recent power plant retirements of electric utilities.

Q. PLEASE DISCUSS YOUR ECONOMETRIC BENCHMARKING METHODOLOGY.

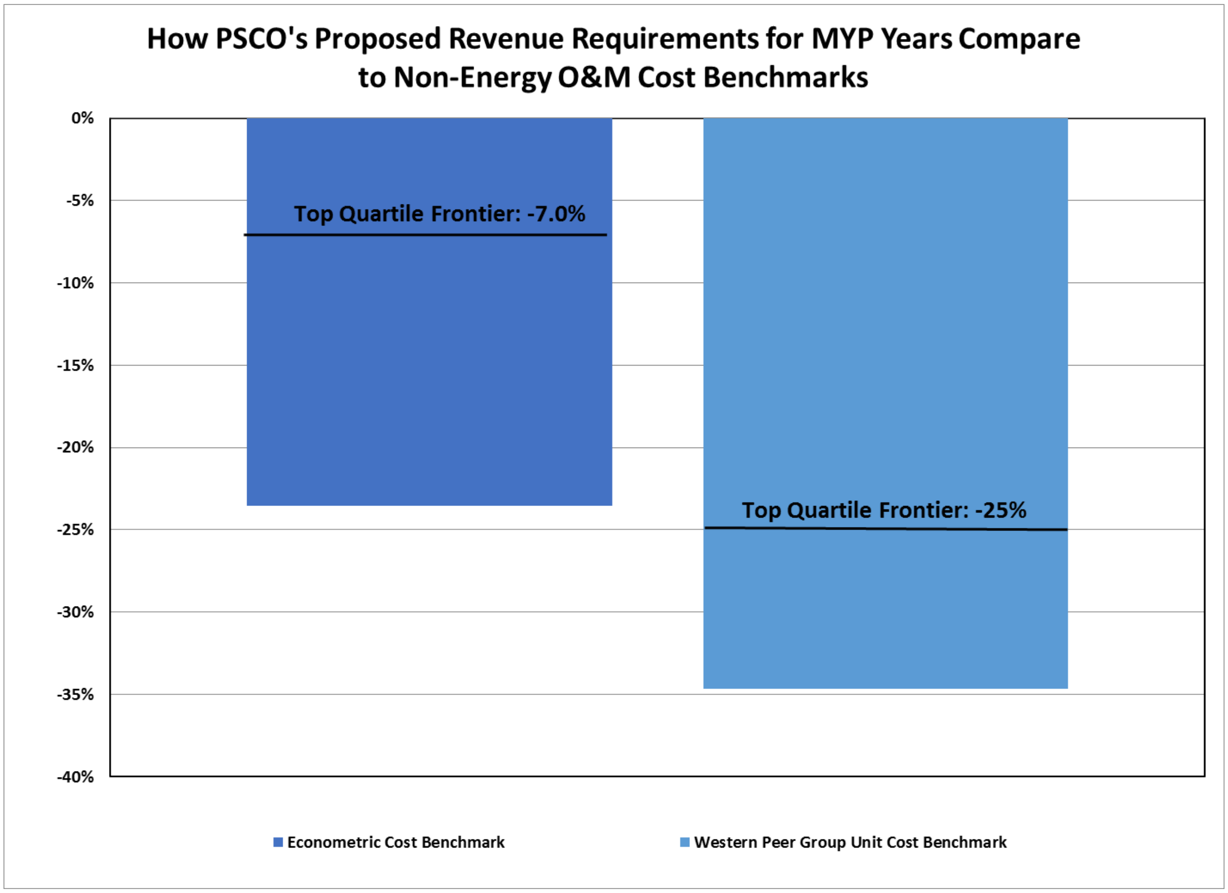
A. Guided by economic theory, we developed a model of the impacts various quantifiable business conditions have on the non-fuel O&M expenses of VIEUs. The parameters of the model, which measure the impact of each business condition variable on cost, were estimated statistically using historical data on utility operations. The econometric research was based on a sample of data for 54 American VIEUs.

The sample period for cost model estimation was 1996 through 2016. The sample has 1,134 observations and is large and varied enough to permit development of a sophisticated cost model in which several cost drivers can be identified. All estimates of business condition parameters were plausible and statistically significant. A model fitted with econometric parameter estimates and values for the business condition variables which Public Service expects to face during the years of the proposed plan generated benchmarks for their proposed revenue requirements.

Q. WHAT ARE THE RESULTS OF YOUR ECONOMETRIC BENCHMARKING WORK?

A. The non-fuel O&M revenue proposed by Public Service is about 23.6 percent below the benchmarks generated by our econometric cost model on average during the four MYP years. This score is commensurate with a top quartile (specifically fourth of 54) ranking. This result is depicted in Figure MNL-D-11.

Figure MNL-D-11



Q. PLEASE DISCUSS YOUR UNIT COST BENCHMARKING WORK AND ITS RESULTS.

A. We compared the Company's proposed real (inflation-adjusted) unit non-fuel O&M revenue during the four MYP years to the corresponding unit costs of a peer group of 12 VIEUs in 2016. The proposed unit O&M revenue requirements were about 34.7 percent percent below the peer group mean on average during the four plan years. This score is commensurate with a top quartile (specifically number two of thirteen) ranking. This result is also depicted in Figure MNL-D-11.

Q. PLEASE SUMMARIZE THE RESULTS OF THE BENCHMARKING WORK

A. Using two rigorous benchmarking methods, we have found that the Company's proposed electric O&M revenue requirements during the MYP years offer customers good value.

B. O&M Revenue Escalator

Q. PLEASE DISCUSS YOUR WORK TO DEVELOP AN O&M REVENUE ESCALATOR FOR PUBLIC SERVICE.

A. We developed a non-fuel O&M revenue escalator for Public Service which is consistent with cost theory and regulatory precedent and appropriate for a vertically integrated electric utility. This index could escalate O&M revenue in a hybrid ARM or a rate case with a single forward test year. In either case the escalation is based on market forces and reduces the role for utility forecasting.

We developed the index with data from our econometric cost research. The formula for the escalator is

$$\textit{growth Revenue}^{O\&M} = \textit{growth Input Prices}^{O\&M} - X + \textit{growth Scale}. \quad [4]$$

Here the X factor is the 0.50 percent growth trend in the non-fuel O&M productivity of the 54 sampled VIEUs from 1997 to 2016. *Scale* is an index that summarizes growth in three scale variables: generation capacity and volume and the number of customers served. The weight for each scale variable in this index is its share in the sum of the cost elasticity estimates for these variables that we obtained from the econometric research.

Q. WHAT ARE THE RESULTS OF THIS INDEXING EXERCISE?

A. In the five years from 2016 to 2021, the forecasted average annual growth rate in the summary non-fuel O&M input price index we used in the benchmarking work is 2.30 percent.[31] Public Service forecasts average annual growth of its generation capacity, volume, and number of electric customers of -0.63 percent, -1.48 percent, and 1.03 percent respectively. The summary scale index would average 0.31 percent growth. Given, additionally, the 0.50 percent industry non-fuel O&M productivity trend, the resulting average annual O&M revenue escalation during the MYP period is 2.11 percent.

Public Service is proposing growth in its non-fuel O&M expenses not slated for tracker treatment that would average 1.77 percent annually from 2016 to 2021. The difference between the 2.11 percent forecasted average annual growth in our O&M revenue escalation index and the 1.77 percent growth in allowed revenue which the Company proposes is an estimate of the stretch factor that is implicit in their proposal. This implicit stretch factor is 0.34 percent. Approved stretch factors in indexed rate and revenue caps of North American energy utilities typically range between 0 and 0.60 percent. Stretch factors in the neighborhood of 0.3 percent are typically reserved for *average* cost performers whereas Public Service has been shown to be a *superior* O&M cost performer.

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

VI. IMPACT OF HISTORICAL TEST YEARS ON UTILITY COST MANAGEMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I discuss in this section my statistical research to consider the contention that the use of historical test years in rate cases improves utility performance.

Q. PLEASE SUMMARIZE THE METHODS YOU USED TO STUDY THE IMPACT OF HTYS.

A. We developed an econometric model of growth in real (inflation-adjusted) non-fuel O&M expenses of VIEUs. We found that real cost growth depends on growth in a scale index like that used in our O&M revenue escalation index. We need to control for this business condition if we wish to identify the effect of a particular kind of test year on cost trends. We added to the cost growth model a binary ("dummy") variable to measure any tendency of cost to grow more slowly for utilities that operated under historical test years throughout the sample period.

Q. WHAT ARE THE RESULTS OF THIS RESEARCH?

A. After controlling for the identified cost drivers (inflation and scale growth), we found that the cost growth of utilities operating under historical test years was slightly *more* rapid but the estimated impact was not statistically significant. I obtained similar results in previous studies I prepared for Public Service rate cases. All of my studies square with my conviction, based on more than two decades of incentive regulation research, that the type of test year a utility uses in rate cases is not a major determinant of its cost containment incentives.

VII. NEED FOR REVENUE ESCALATION UNDER DECOUPLING

Q. PLEASE DISCUSS YOUR EMPIRICAL RESEARCH TO ADDRESS CONCERNS THAT ESCALATING REVENUE FOR CUSTOMER GROWTH COULD OVERCOMPENSATE PUBLIC SERVICE UNDER REVENUE DECOUPLING.

A. Earlier in my testimony I noted that growth in operating scale is not the only source of utility cost growth. For example, cost growth also depends on input price and productivity growth. When input price inflation materially exceeds productivity growth, it is unlikely that a revenue decoupling system that escalates allowed revenue for customer growth will result in overcompensation.

To illustrate the likelihood of overcompensation for a VIEU today, we gathered data from FERC Form 1 and other publicly available sources on the trends in the pro forma total non-fuel cost of base-rate inputs in our sample of 54 American VIEUs. The sample period was 1998-2016. Costs considered in our study included most non-fuel O&M expenses, amortization, depreciation, and tax expenses, and a pro forma return on net plant value.

Over the full sample period, the 3.86 percent average annual growth in the pro forma non-fuel cost of base rate inputs far exceeded the 1.08 percent growth trend in the number of customers served. It also exceeded the 1.87 percent trend in the GDPPI. For the typical VIEU, overearning is therefore unlikely under revenue per customer decoupling. This helps to explain why, when a decoupling system escalates allowed revenue only for customer growth, utilities usually retain the freedom to file rate cases and occasionally do file. In the absence of an MYP there is little risk that revenue-per-customer decoupling would produce overearning for Public Service.

VIII. <u>CONCLUSIONS</u>

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE COMPANY'S MYP PROPOSAL?

A. All in all, I consider this plan a sensible and prudent next step in the regulation of the Company's electric services using MYPs. Public Service has proposed a comprehensive MYP that is well within the mainstream of industry precedents. MYPs make sense for electric and gas utilities under modern operating conditions. Customer protections in the proposed plan are unusually strong. My empirical research found the proposed revenue requirement to offer customers good value.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Mark Newton Lowry

Mark Newton Lowry is President of Pacific Economics Group Research LLC, a consulting firm that works primarily in the field of energy utility economics. He has more than thirty years of experience as an industry economist. Utility performance measurement and MYPs have been his chief professional focus for almost three decades. Dr. Lowry is also an expert on forward test years, revenue decoupling, and miscellaneous other alternatives to traditional utility rate regulation that are collectively called alternative regulation or “Altreg.” He has testified dozens of times on Altreg and utility performance measurement issues. Work for diverse clients that include regulatory commissions, government agencies, and consumer and environmental groups as well as utilities has given his practice a reputation for objectivity and dedication to good regulation.

Benchmarking costs of vertically integrated electric utilities like Public Service is a specialty. Dr. Lowry has also benchmarked the reliability of electric utilities and the costs these utilities incur in power generation, transmission, distribution, and administrative and general services. Dr. Lowry has done benchmarking research and testimony for Public Service several times. He has also testified on benchmarking for AmerenUE, Atlanta Gas Light, Boston Gas, Central Vermont Public Service, Enbridge Gas Distribution, FortisAlberta, Hydro One Networks, Kentucky Utilities, Louisville Gas & Electric, the Michigan Public Service Commission, NMGas, Oklahoma Gas & Electric, the Ontario Energy Board, Pacific Gas & Electric, Portland General Electric, Progress

Energy Florida, Public Service of Colorado, San Diego Gas & Electric, Southern California Edison, and Southern California Gas. Other clients of his benchmarking services have included the Canadian Electricity Association (Canada), AGL Electricity, the Australian Energy Regulator, Powerlink Queensland, Networks New South Wales, the Queensland Competition Authority (Australia), the Superintendencia de Electricidad (Bolivia), EDF London, EDF Eastern, EDF Seeboard, Northern Electricity Distribution, Yorkshire Electricity Distribution, and United Utilities (England), the Central Research Institute for the Electric Power Industry (Japan), and Central Maine Power, Commonwealth Edison, Delmarva Power and Light, Niagara Mohawk Power, Pennsylvania Power & Light, and Public Service Electric & Gas (United States).

Dr. Lowry pioneered the use of input price and productivity research in energy utility regulation. He has testified numerous times on the productivity trends of gas and electric utilities and published articles on his productivity research in the *Review of Network Economics* and the *AGA Forecasting Review*. He routinely calculates O&M and capital productivity as well as multifactor productivity. In addition to Public Service he has provided productivity research and testimony for Atlanta Gas Light, Atlantic City Electric, Bangor Hydro-Electric, Boston Gas, Central Maine Power, the Consumers' Coalition of Alberta, the Commercial Energy Consumers of British Columbia, Delmarva Power, Gaz Metro, the Gaz Metro Consumer Task Force, Hawaiian Electric, Hawaiian Electric Light, Maui Electric, Niagara Mohawk Power, NMGas, the Ontario Energy Board, Potomac Electric Power, San Diego Gas & Electric, Southern California Gas, and Unitil. Other clients he has assisted on productivity issues include SPI Networks

(Australia), the Superintendencia de Electricidad (Bolivia), and Baltimore Gas & Electric, Duke Energy, Illinois Power, the Interstate Natural Gas Association of America, New England Gas, NSTAR, and Public Service Electric and Gas.

Dr. Lowry has for many years advised the Edison Electric Institute ("EEI") on MYPs and other forms of Altreg. He has prepared several EEI surveys and white papers on Altreg, including a widely read paper on forward test years. He recently added to his published work on MYPs two white papers for Lawrence Berkeley National Laboratory.

Before joining PEG, Dr. Lowry was a Vice President at Christensen Associates and an Assistant Professor teaching energy economics at the Pennsylvania State University. His resume includes numerous other professional publications and many speaking engagements. He has chaired several conferences on Altreg and utility performance measurement. A Cleveland area native, he attended Princeton University and holds a Ph.D. in applied economics from the University of Wisconsin – Madison.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-_______E**

**AFFIDAVIT OF MARK N. LOWRY
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Mark N. Lowry, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Madison, Wisconsin, this 15th day of September, 2017.

Mark N. Lowry
President, Pacific Economics Group Research, LLC

Subscribed and sworn to before me this 15 day of September, 2017.

BRANDON J DAY NOTARY PUBLIC STATE OF WISCONSIN

Notary Public

My Commission expires 05/22/2021

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

Pacific Economics Group Research, LLC

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

September 28, 2017

Mark Newton Lowry, Ph.D.
President

David Hovde, M.S.
Vice President

Alex Verbny, M.S.
Economist II

Matt Makos
Consultant II

PACIFIC ECONOMICS GROUP RESEARCH LLC
44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

TABLE OF CONTENTS

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

[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:

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

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

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

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

---

[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:

$$\textit{Cost = Input Prices • Input Quantities.} \qquad [4]$$

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.

---

[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.

---

[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

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

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.

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	Peers	Comparing Results	
	2018-2021 Average	2016	Ratio	Percentage Difference
	[A]	[B]	[A/B]	[(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.

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

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

[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%**	**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]

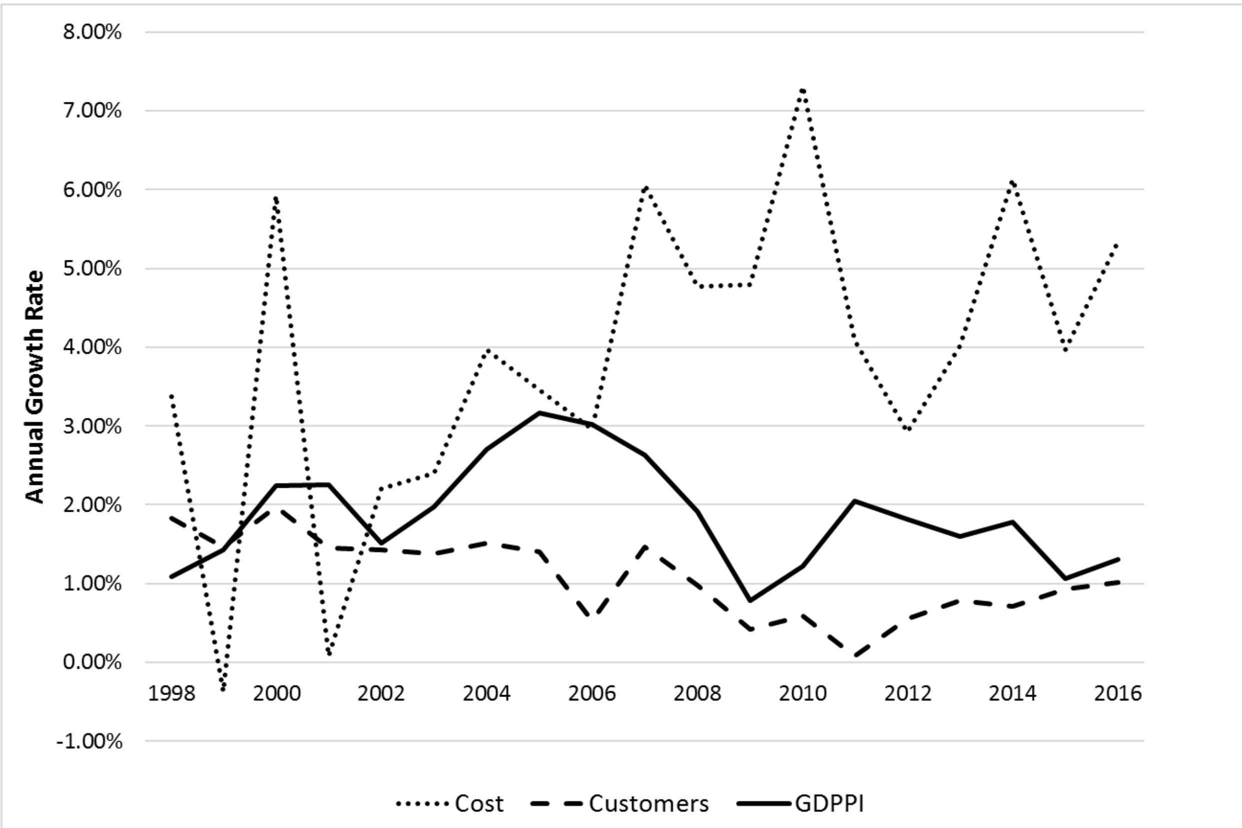
	Non-Fuel Cost [%] [A]	Customers [%] [B]	GDPPI [%] [C]
1998	3.37%	1.83%	1.08%
1999	-0.37%	1.46%	1.42%
2000	5.92%	1.98%	2.25%
2001	0.07%	1.45%	2.26%
2002	2.20%	1.43%	1.52%
2003	2.40%	1.38%	1.98%
2004	3.96%	1.51%	2.71%
2005	3.46%	1.41%	3.17%
2006	2.96%	0.53%	3.02%
2007	6.06%	1.46%	2.63%
2008	4.76%	0.98%	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%**

[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:

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

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.

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

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,

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

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.

References

Denny, Michael, 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.

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