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

*** * * * ***

RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**)))))))))**	**PROCEEDING NO. 17AL-______G**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 2, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
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SUMMARY OF THE DIRECT TESTIMONY OF MARK N. LOWRY

Mark N. Lowry is President of Pacific Economics Group Research, LLC ("PEG"). He is an expert on multiyear rate plans ("MYPs") and pioneered the use of productivity and rigorous benchmarking research in North American energy utility regulation. In addition to his management duties, Dr. Lowry serves as principal investigator for many of his company's projects. His work includes research on utility performance and new forms of regulation, consultation with clients, and expert witness testimony. Work for a mix of utilities, regulators, consumer and environmental groups, and government agencies have 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"), 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 that the Company is proposing for its gas services. His appraisal draws both on his decades of experience in the field and on statistical research undertaken expressly for this proceeding. The research uses well-established indexing and benchmarking methods. This kind of rigorous research to support proposed MYP revenue requirements is rarely commissioned by North American utilities.

Dr. Lowry details in his testimony many advantages of the MYP approach to regulation. Regulation is more efficient and effective. Rate trajectories can be smoother and more predictable. Benchmarking is often used in plan design, and this is a valuable complement to prudence reviews in ensuring that a utility's rates offer customers good value.

The rates established in MYPs give a utility a reasonable chance to earn its authorized return without closely tracking the costs that it actually incurs. This, along with the challenge posed by benchmarking, gives the utility a business environment more like that which its customers in competitive markets face. Incentives to embrace demand-side management can be strengthened. Research by Dr. Lowry has revealed that utility performance often improves under MYPs. Benefits can be shared between utilities and their customers. Advantages of MYPs are especially pronounced in a period like the present when the alternative is frequent rate cases triggered by adverse business conditions. His commentary specifically considers the use of MYPs in gas service regulation.

There are numerous precedents for MYPs for gas and electric utilities. Regulators recognize the strong performance incentives and more efficient regulation that MYPs can provide. The impetus for MYPs sometimes comes from regulators and other policymakers. Use of MYPs has been growing rapidly in the regulation of vertically integrated electric utilities. The Commission has already approved two MYPs (as I define them) for electric services of Public Service, along with MYPs for incumbent local telecommunications carriers. Use of MYPs to regulate gas utilities is becoming the norm in populous provinces of Canada and many countries overseas.

Public Service is proposing a comprehensive MYP for its provision of gas services, which is very much in line with industry precedent. Rate cases would be less frequent. The trajectory of gas rates would be smoothed and more predictable, thanks in part to the proposed termination after 2018 of the Pipeline System Integrity Adjustment.

Proposed plan provisions are typical of first-generation plans. Many provisions are already part of the regulatory system for the Company's gas services. An earnings test that shares surplus earnings but not earnings shortfalls with customers is similar to that in the MYP for the Company's electric services.

Statistical research undertaken by PEG and supervised by Dr. Lowry revealed that the proposed revenue requirements during the plan years offer customers good value. Using two well-established benchmarking methods, the proposed revenue requirements for non-gas operations and maintenance ("O&M") expenses and total non-gas cost were found to be commensurate with good cost performance. These results are remarkably favorable given the integrity management costs that the Company has had to incur in recent years. The proposed escalation of revenue for O&M expenses is considerably less than would be yielded by an O&M escalation index. Further support for the proposal comes from the extensive information the Company has provided about its gas business plan.

The alternative to an MYP is a continuation of a regulatory system that has produced high regulatory costs, weak performance incentives, and chronic under earning. Dr. Lowry recommends that the Commission embrace the MYP approach to regulation for the Company's gas services and approve the plan proposed.

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DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ARM	Attrition Relief Mechanism
Capex	Capital Expenditures
CMP	Central Maine Power
Commission	Colorado Public Utilities Commission
COSR	Cost of Service Approach to Regulation
DSM	Demand-Side Management
ECM	Efficiency Carryover Mechanism
ESM	Earnings Share Mechanism
FERC	Federal Energy Regulatory Commission
FTY	Forward Test Year
GDPPI	Gross Domestic Product Price Index
HTY	Historical Test Year
LDCs	Local Gas Distribution Companies
LRAM	Lost Revenue Adjustment Mechanism
MFP	Multifactor Productivity
MYP	Multiyear Rate Plan
M&S	Material and Service

Acronym/Defined Term	**Meaning**
O&M	Operations and Maintenance
PBR	Performance Based Regulation
PEG	Pacific Economics Group Research, LLC
PEG Report	Report on empirical research
PIM	Targeted Performance Incentive Mechanism
PSIA	Pipeline System Integrity Adjustment
Public Service, or the Company	Public Service Company of Colorado
QSP	Quality of Service Plan
ROE	Rate of Return on Equity
U.S.	United States
VIEU	Vertically Integrated Electric Utility

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DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS

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. I, together with other members of the PEG team, pioneered the use of rigorous benchmarking and productivity research in the regulation of North American energy utilities. We have also played a prominent role in the growing use of the multiyear rate plan ("MYP") approach to regulation in North America. Work for a mix of clients that includes regulators, government agencies, and consumer and environmental groups as well as utilities have given our practice a reputation for objectivity and dedication to good regulation.

After more than two decades of work in these fields, I continue to serve as principal investigator for many of our projects. I supervise research on utility performance and trends in regulation, consult with clients, and provide expert witness testimony.

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 from 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. My Direct Testimony provides the Colorado Public Utilities Commission ("Commission") with background information on the MYP approach to regulation. Additionally, I appraise the plan that Public Service is proposing for its gas services. My appraisal draws on my years of work on MYPs and on empirical research undertaken specifically for this proceeding.

During the years of the proposed plan the revenue requirement for capital cost would be forecasted. Revenue for labor expenses (salaries and wages) would rise by 2 percent in each plan year while that for non-labor (e.g., material and service ("M&S") expenses would be frozen. Forecasts are permitted in Colorado rate setting as discussed by Company Witness Mr. Brockett, but in past proceedings some intervenors have questioned the reasonableness of forward test year ("FTY") projections. Stakeholders have also touted the benefits of historical test years ("HTYs") in incentivizing better utility cost performance.

Public Service has asked PEG to undertake three empirical tasks to support its filing. One is to benchmark the Company's proposed revenue requirements in the three MYP years. Another is to develop an index -based escalator for operations and maintenance ("O&M") revenue that includes a productivity adjustment. This escalator is used to appraise the Company's proposed O&M revenue escalation. A third task is to use statistical methods to consider whether HTYs improve utility cost performance. Our empirical work employs a sizable dataset on operations of United States ("U.S.") local gas distribution companies ("LDCs").

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

A. Yes. Attachment MNL-2 is a report on our empirical research ("PEG Report") for Public Service. This report also explains some basic benchmarking and productivity concepts. I supervised the empirical research and prepared the report.

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

A. Several Company witnesses explain the Company's budgeting and cost management procedures to help show why the proposed revenue requirements are reasonable. Company witness Scott Brockett presents the Company's proposed MYP.

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 study of the incentive impact of HTYs is, similarly, an attempt to shed light on this topic using statistical methods and industry data.

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

A. MYPs are a promising approach to energy utility regulation. Rate trajectories can be smoother and more predictable. Benchmarking is often used in plan design, a customer protection that challenges the utility to outperform its peers. Regulation can be more efficient and effective. Utility performance can improve, and benefits can be shared with customers. Customers can also benefit from more market-responsive rates and services. These advantages of MYPs have been recognized by regulators. Incentives for utilities to embrace demand-side management ("DSM") can be strengthened.

Use of MYPs is well established in the regulation of gas and electric utilities and growing rapidly in the regulation of U.S. vertically integrated electric utilities ("VIEUs"). This Commission has already used MYPs to regulate electric services of Public Service. MYPs are the norm for gas utilities in Canada and many companies overseas.

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

A. Based on the study detailed in the PEG Report, which uses two well-established statistical benchmarking methods, I conclude that the Company's proposed revenue requirements for non-gas O&M expenses and non-gas total cost (which includes capital cost) are low by industry standards. This is remarkable considering the substantial costs the Company has incurred in recent years to improve system integrity.

Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR WORK TO DEVELOP AN O&M REVENUE ESCALATOR?

A. We developed an O&M revenue escalation index based on cost theory, productivity research, and regulatory precedent. This index is useful for benchmarking the O&M revenue escalation that Public Service proposes for the three MYP years. Our research suggests that the Company's proposed escalation provides material customer benefits.

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

A. After examining trends in non-gas O&M expenses of LDCs operating under different types of test years, I find no support for the assertion that HTYs strengthen cost performance incentives. MYPs provide a better means of strengthening incentives.

Q. AS A RESULT OF YOUR CONCLUSIONS, WHAT RECOMMENDATION ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Commission embrace the MYP approach to regulation for the gas services of Public Service. Rate growth would be smoother and more predictable. Regulation would be more efficient, and better performance can be encouraged.

Public Service is proposing in this proceeding an MYP for its gas services that has ample precedent. Features of the proposed plan are commensurate with those of good MYPs throughout the country. Several features of the proposed plan are already used by the Commission to regulate the Company's gas or electric services. There are extensive customer protections. My statistical work suggests that the proposed revenue requirement offers customers good value. The alternative to the MYP for the Company's gas services is frequent rate cases that involve high regulatory cost, rate “bumps”, and weak performance incentives. I recommend that the Commission approve the Company’s MYP proposal.

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

A. I will explain in this section the basic idea of an MYP and 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 MULTIYEAR RATE PLAN APPROACH TO REGULATION?

A. Multiyear rate plans 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. In Section 3 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. WHAT IS AN 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). Between rate cases, an ARM permits rates (or the revenue requirement) to grow in the face of cost pressures without closely tracking the cost that the utility actually incurs.[1] These mechanisms sometimes contain productivity growth commitments. Some costs that are difficult to address through the ARM may be addressed separately using cost trackers and associated rate riders or deferral arrangements.

Here is a generic formula for rate escalation in an MYP:

growth Rates = growth ARM + Y + Z.[1]

In this formula, the "Y factor" indicates the rate adjustment for costs, such as energy procurement expenses, which are chosen in advance for tracker treatment. The "Z factor" indicates the rate adjustment for miscellaneous changes in cost beyond the control of the utility which may occasionally be accorded tracker treatment. Events that can trigger a Z factor adjustment include government mandates (e.g., to relocate facilities due to highway construction) and force majeure events such as severe storms. I discuss ARM design further in Section 3 of this testimony.

[1] MYPs are thus quite different from the cost of service formula rate plans used to regulate gas utilities in several southeastern states.

Q. WHAT IS A 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 performance metrics. Targets are established for some metrics, and performance can be gauged by comparing the utility's value to the target. Some metrics are used in performance incentive mechanisms ("PIMs") that link revenue to measured performance in targeted areas. Most commonly, there are PIMs to strengthen incentives for utilities to maintain or improve safety, reliability, and customer service quality.

Q. CAN PROVISIONS BE ADDED TO PLANS TO ENCOURAGE DSM?

A: Yes. DSM can lower the cost of meeting customer energy needs. Many MYPs contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked. Performance incentive mechanisms can be added to plans which reward utilities for successful DSM programs. Revenue decoupling and/or a lost revenue adjustment mechanism can reduce the short-term link between a utility's revenue and system use.[2]

[2] A good reference on revenue decoupling is J. Lazar, F. Weston, and W. Shirley, "Revenue Regulation and Decoupling: A Guide to Theory and Application," Regulatory Assistance Project, 2016.

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") deviates from the commission-approved target.[3] Off-ramp mechanisms permit review of a plan under pre-specified outcomes such as extreme ROEs. I provide more detail on ESMs later in my Direct Testimony.

Q. WHAT IS THE MARKETING FLEXIBILITY AND PLAN TERMINATION PROVISIONS REFERRED TO IN FIGURE MNL-D-1?

A. Some MYPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. This 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 in fulfillment of commission-approved goals.

Plan review and termination provisions are also important in MYPs. Some plans provide for a review towards the end of the term. These reviews sometimes result in a plan extension without a general rate case.

To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited in the next rate case.

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[3] Earnings sharing mechanisms are discussed further in the next section.

For example, the utility may be permitted to keep a share of any measurable cost savings that are reflected in the new revenue requirement. Provisions of this kind are sometimes called efficiency carryover mechanisms.

B. MYPs and Traditional Cost of Service Approach

Q. WHAT IS THE RATIONALE FOR USING MYPS?

A. To explain the rationale for these plans I will first consider basic features of the cost of service approach to regulation ("COSR"), which is still widely used in the U.S., and then discuss reasons that some jurisdictions have adopted MYPs.

Q. WHAT ARE THE BASIC FEATURES OF COSR?

A. Under COSR the base rates that address costs of capital, labor and materials are reset in rate cases at levels that more effectively recover that portion of a utility's cost of service which regulators deem prudent. Historical test years were traditionally used in rate cases but forward test years are now used in many jurisdictions where COSR is practiced. 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. 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 is drawn from usage charges (e.g., charges per Dth of deliveries). The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (i.e., the capacity to provide peak day sendout and deliver gas to multiple, scattered locations) than by growth in system use. The number of customers served is highly correlated with peak demand and an important cost driver in its own right.[4] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (also known as average use). An energy distributor's earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining 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. My research over the years has suggested that the efficacy of COSR depends on external business conditions. When conditions are favorable, revenue growth matches or may even exceed cost growth. Rate cases are infrequent and performance incentives can be strong.

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 the operating conditions facing utilities are

[4] This is 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.

continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

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 can be diminished, and this weakens utility incentives to contain cost growth. Expanded use of cost trackers can reduce the frequency of rate cases and thereby helps to preserve incentives to contain many costs. However, incentives to contain newly tracked costs may be weakened unless these costs are carefully monitored.

Since frequent rate cases and expanded use of cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable. With historical test years, chronically adverse business conditions can also cause utilities to chronically under earn.

Rates that closely track a utility's cost of service also produce occasional rate "bumps". These can harm customers and make it difficult 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 biennial 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.[5]

Q: IS THERE EMPIRICAL EVIDENCE TO SUBSTANTIATE YOUR CLAIM THAT ADVERSE BUSINESS CONDITIONS IMPAIR COSR'S EFFECTIVENESS?

A: Yes. As one example, the federal government calculated an index of the multifactor productivity ("MFP") growth of the electric, gas, and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[6] PEG has compared the MFP growth of this sector in a period when business conditions for utilities were favorable with growth 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 growth reflects changes in diverse

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

[6] 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.

business conditions that affect costs, including technological change and realization of scale economies. A multifactor productivity index considers productivity in use of capital, labor, and materials. The PEG Report 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 the average use of energy by residential and commercial customers; and
- price inflation, measured here by the gross domestic product price index ("GDPPI").[7]

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 average use of energy (gas or electricity) by residential and commercial customers. We report trends in the attrition indicators over several subperiods between 1931 and 2015.

Results show that these business conditions were quite favorable on balance from the late 1920s until the late 1960s. Except in the 1940s, inflation

[7] The GDPPI is the federal 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	Average Annual Electricity Use			Average Annual Natural Gas Use			GDPPI Inflation[4]	Summary Attrition Indicators	
	Residential[1]	Commercial[1]	Average [A]	Residential[2]	Commercial[3]	Average [B]	[C]	Electric [C]-[A]	Natural Gas [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% [6]	0.94% [6]	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).

was generally slow. Average use of gas and electricity grew rapidly. Rapid demand growth presented outsized opportunities to realize scale economies.

Inflation accelerated markedly after 1967. Business conditions grew even more adverse for gas and electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities, like coal and natural gas, which utilities purchased in large quantities, was especially rapid. Combined with slower economic growth, this caused growth in average use of electric power by residential and commercial customers to slow markedly. Average use of gas started falling. Slowing demand growth reduced opportunities to realize further scale economies.[8]

Rate cases were much more frequent. Figure MNL-D-3 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[9] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

From 1987 to 2007, inflation slowed to a pace more typical of the 1950s and 1960s. However, average use of gas continued to decline, while sluggish growth in average use of electricity continued. Business conditions thus improved for utilities on balance but were less favorable than those in the decades preceding the first oil price shock.

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[8] Some utilities may have exhausted their potential to realize economies.

[9] Braeutigam, R. and Quirk, J., "Demand Uncertainty and the Regulated Firm," *International Economic Review*, Vol. 25, No. 1, 1984, p. 47.

Figure MNL-D-3 U.S. Electric Utility Rate Cases: 1948-1977[10]

Period	Number of	Company Initiated Rate Cases			PUC Initiated
	Rate Cases	Number	Rate Increases	Rate Decreases	Rate Cases
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 and Figure MNL-D-5 show the trend in MFP growth of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1949 to 1998. 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 growth of electric, gas and sanitary utilities fell to 2.31 percent during the 1968-72 period and to zero on average 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 U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[11]

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[10] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potentially excessive utility earnings.
[11] A basis point is one-hundredth of 1 percent.

Figure MNL-D-4 Multifactor Productivity Growth of Electric, Gas, and 6Sanitary Utilities and the U.S. Private Business Sector: 1949-1998

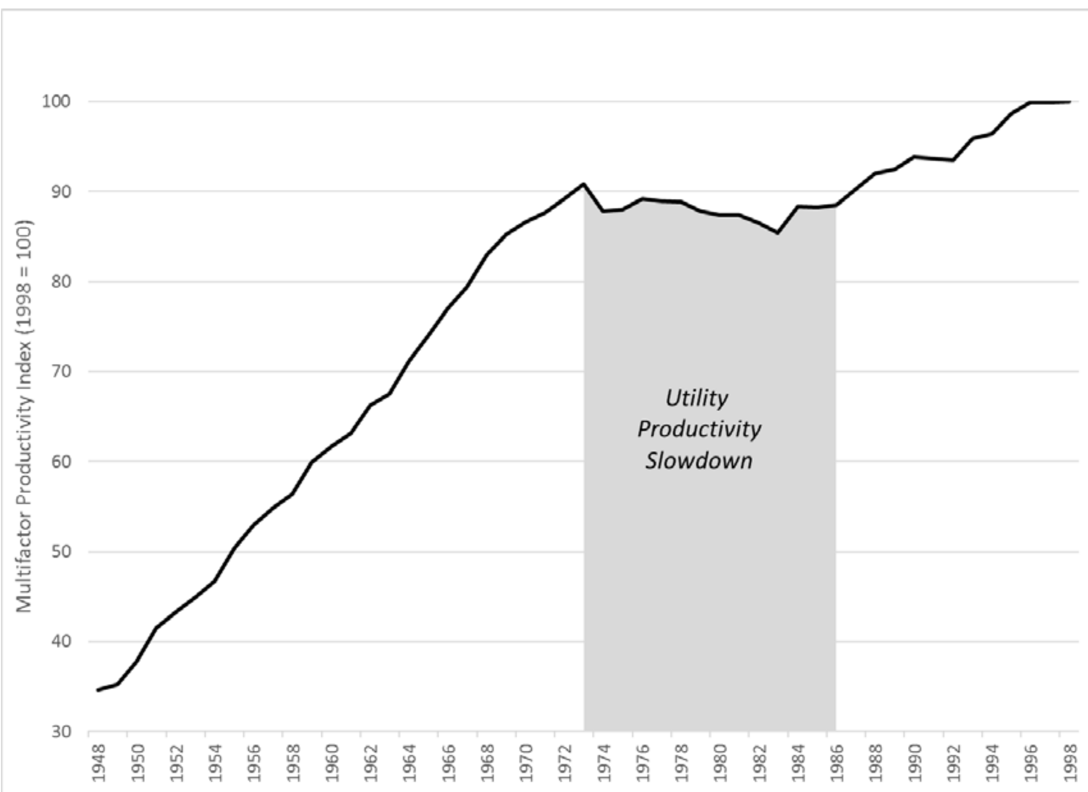
	Electric, Gas, and Sanitary Utilities[1] [A]	U.S. Private Business Sector[2] [B]	MFP Growth Differential [A - B]
Annual Averages			
1949-1967	**4.36%**	**2.24%**	**2.12%**
1968-1972	**2.31%**	**1.58%**	**0.73%**
1973-1986	**-0.05%**	**0.67%**	**-0.72%**
1987-1998	**1.02%**	**0.73%**	**0.29%**

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

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

Figure MNL-D-5 Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948-1998)



MFP growth of utilities resumed at a slower 1.0 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP growth exceeded that in the private business sector by a modest 29 basis points annually on average in these years.

We conclude that the MFP growth of the utility sector was much more rapid in the decades before 1973 when business conditions generally favored utilities. This was the "golden age" of COSR when this regulatory system became a tradition.

Q. HOW DO THE BUSINESS CONDITIONS LDCS LIKE PUBLIC SERVICE FACE TODAY COMPARE TO THOSE IN THE "GOLDEN AGE" OF COSR?

A. Figure MNL-D-2 above shows that business conditions since 2007 have been considerably less favorable to gas and electric utilities than in the golden age. In the case of LDCs brisk growth in average use has been replaced by static or declining average use. There are fewer opportunities to realize scale economies. Spurred by aging systems and state and federal policies such as the Pipeline Safety Improvement Act, many LDCs need high levels of capex that don't automatically trigger extra revenue. The situation would be much worse were it not for unusually slow price inflation. Unfortunately, price inflation may well rebound in coming years.

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 good 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. Benefits of adopting MYPs are greater to the extent that rate cases are adverse and rate cases are frequent.

Q. PLEASE DISCUSS HOW 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, ARM escalation is based on a forecast of the utility's cost, industry cost trends, or both, and not on growth in the cost that the utility actually incurs. This increases opportunities for a utility 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 customers serving competitive markets experience. The addition of a well-designed efficiency carryover mechanism to the plan termination provisions can magnify the incentive "power" of an MYP.

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

A: No. Rate cases that use HTYs tend to undercompensate utilities in periods like the present, when cost is rising faster than billing determinants. This feature of HTYs does strengthen performance incentives. But utilities retain the right to file rate cases as needed. The same business conditions that cause undercompensation cause rate cases to be filed more frequently, and this erodes incentives. What matters for incentives is that revenue does not track the utility's own cost too closely. Undercompensating a utility is only one way of achieving this. MYPs can provide stronger performance incentives at the same time that they provide timely and compensatory rate relief.

Q: CAN MYPS ENCOURAGE BETTER PERFORMANCE IN OTHER WAYS?

A: Yes. MYPs can also encourage good utility performance by increasing operating flexibility in areas where such need is recognized. Reduced rate case frequency means that the prudence of utility actions must be considered less frequently. Furthermore, utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). 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 (e.g., discounts and special contracts offered to large-load customers).

Q. DO MYPS HAVE OTHER NOTEWORTHY BENEFITS?

Yes. Customers can benefit from more predictable rate growth and more market-responsive rates and services. Rate trajectories can be sculpted to diminish rate bumps. Statistical benchmarking is often used in plan design. This is a useful complement to prudence reviews in ensuring that the rates utilities charge are commensurate with good operating performance.

The PIMs added to MYPs also play a role in encouraging good utility performance. 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 abruptly if the quality of its offerings falls. Safety problems can trigger costly lawsuits. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.

Advantages of MYPs in encouraging utilities to consider cost-effective DSM are material but not widely recognized. These plans can strengthen incentives to use DSM to contain load-related costs of base rate inputs. The combination of an MYP, revenue decoupling and/or a lost revenue adjustment mechanism ("LRAM"), PIMs to encourage efficient DSM, and the tracking of DSM-related costs can provide four "legs" for the DSM "stool."[12]

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[12] 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.

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 create 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 careful ARM design.

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 the gas and electric services of the Company 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 such as rate designs and system planning. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively.

Q. WHAT ARE SOME DISADVANTAGES OF THE MYP APPROACH?

A. MYPs are often 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. There are opportunities for strategic behavior that erodes potential plan benefits. However, best practices in the MYP approach to regulation have evolved continually to address such problems.

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, which faced significant competitive challenges and complex, changing customer needs that complicated regulation. US West and its successor, Qwest, have operated under MYPs in Colorado.[13] MYPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn a superior return for superior performance. Both industries achieved rapid productivity growth under MYPs. Some states still use MYPs to regulate telecommunication services in less competitive markets.[14] The Federal Energy Regulation Commission ("FERC") uses MYPs to regulate oil pipelines.[15]

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[13] 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.

[14] See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.

[15] 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.

MYPs have also been used to regulate natural gas and electric utilities.[16] California's commission has required utilities to use MYPs since the 1980s. MYPs became popular in several northeastern states in the 1990s. In addition to formal rate plans, 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-6 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 diverse states that include Arizona, Georgia, Virginia, and Washington. This Commission has already approved the MYP approach for electric services of the Company.[17] An MYP was recently approved for electric services of Public Service's affiliate in Minnesota, Northern States Power Company, a Minnesota corporation. Many states also have recently experimented with "mini" MYPs involving only two plan years.

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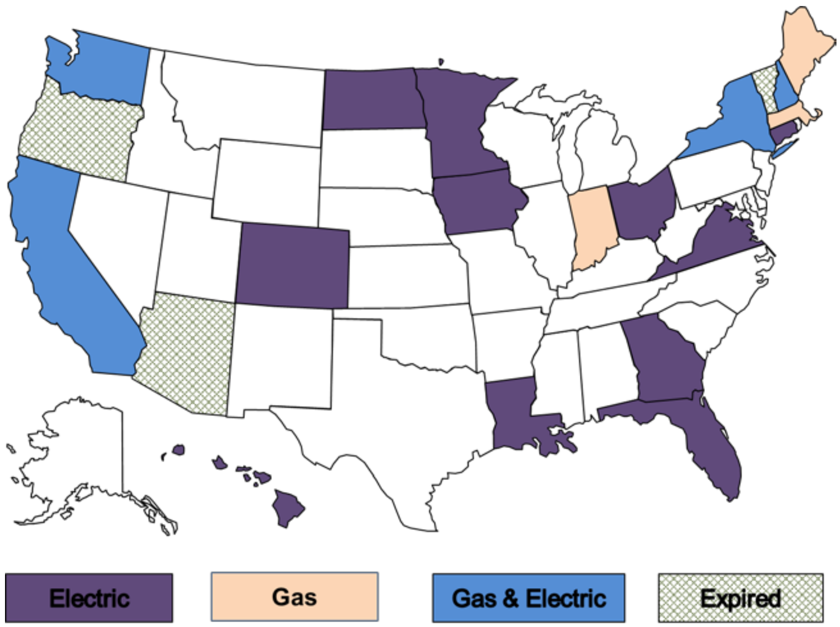
[16] MYP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The latest is Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

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

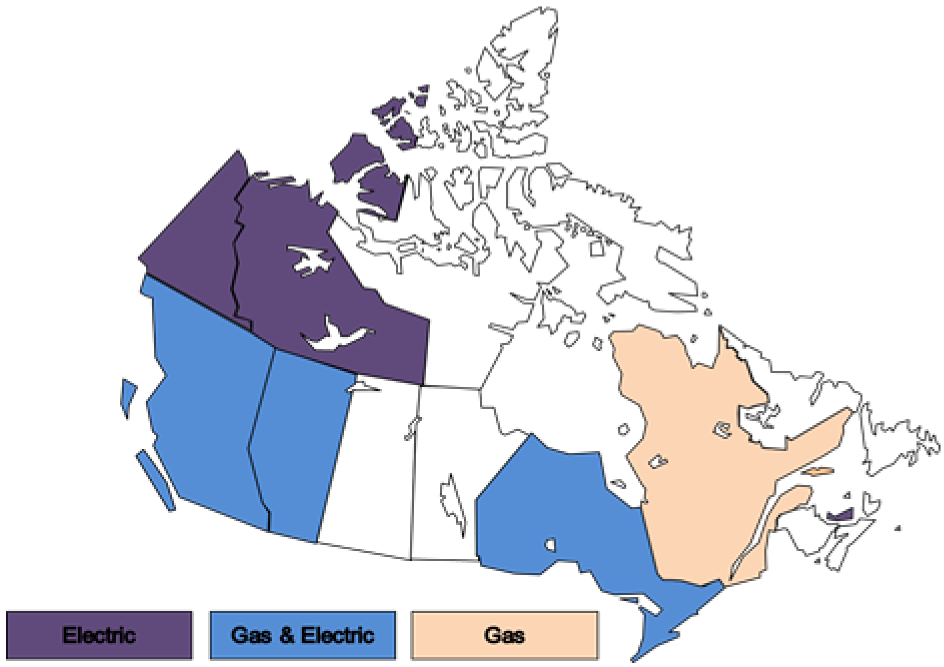
Figure MNL-D-6 *MYPs in the U.S.*



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

A. Yes. Figure MNL-D-7 shows that MYPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MYPs are the norm in Australia, Ireland, New Zealand, and the United Kingdom. Countries that use MYPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MYPs are also common in Latin America.

Figure MNL-D-7 Recent MYPs in Canada.



Q: DOES THE IMPETUS FOR MYPS IN THESE COUNTRIES TYPICALLY COME FROM UTILITIES?

A: No. Impetus for adopting MYPs in other countries has often come from regulators and other policymakers. For example, provincial law in Quebec requires the Régie de l'Energie to use approaches to regulation for the large electric utility in the province (Hydro-Québec) that streamline regulation, encourage continual performance gains, and share benefits with customers.[18] The Régie has ordered Hydro-Québec to operate prospectively under an MYP that it opposed.

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[18] 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.

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

A. Yes. For example, the Washington Utility and Transportation Commission stated the following in recently approving MYPs for 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.[19]
>
> 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.[20]

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

[19] Washington Utilities and Transportation Commission's Order 07 in Dockets UE-121697, UG-121705, UE-130137, and UG-130138, June 2013, p. 66.
[20] *Ibid*., p 75.

> 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.[21]

This Commission has twice rejected MYPs for the Company's gas services but stated in one of its decisions that:

> we agree with Public Service that an MYP can be beneficial for both customers and the Company, particularly due to reduced rate case expenses and the stability and predictability of rate increases that an MYP provides.[22]

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

A. Yes. I have written several treatises on MYP design.[23] Lawrence Berkeley National Laboratory will soon release a new white paper I have written about MYPs. It discusses the rationale for MYPs and plan design challenges and presents six case studies. The study found that MYPs generally improve utility performance in addition to lowering regulatory cost.

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

[22] Public Utilities Commission of Colorado, Decision C13-1568, Docket No. 12AL-1268G, December 2013, p. 11.

[23] See, for example, M. Lowry and L. Kaufmann, "Performance-Based Regulation of Utilities," *Energy Law Journal*, October 2002. Other notable treatises 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.

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 lawyer. In a 1993 rate case decision, Maine's commission encouraged CMP to operate under an MYP. 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."[24] The 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; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[25]

Maine's 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

[24] Maine Public Utilities Commission, Order dated December 14, 1993, Docket No., 92-345, pp. 14-15.
[25] Maine Public Utilities Commission, *op. cit.*, p. 126.

> 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.[26]

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

A. CMP operated under three successive "alternative rate plans" from 1995 to 2013. Full rate cases did not occur between these plans. During these years, CMP achieved distributor productivity growth well above the national norm, as shown in Figure MNL-D-8. CMP's success in containing capital spending during these years is especially notable.

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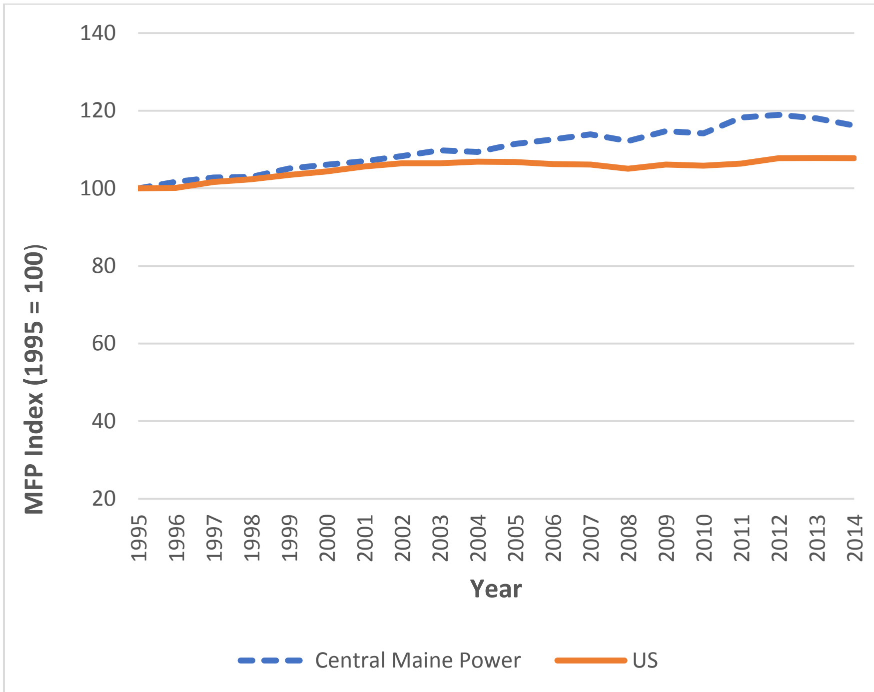
[26] Maine Public Utilities Commission, *op. cit.,* p. 130.

Figure MNL-D-8 CMP's Distributor Productivity Growth Under MYPs



Source: Mark Newton Lowry, Matthew Makos, and Jeff Deason, *Multiyear Rate Plans for U.S. Electric Utilities*, 2017 forthcoming.

II. 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.

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 utility cost trends. For example, a revenue requirement escalator for a gas distributor might take the following form:

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Customers} + Y + Z \qquad [2]$$

The inflation measure in relation [2] is often a macroeconomic price index such as the U.S. Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes used in ARM design. The X variable, which is sometimes called the productivity factor or “X factor,” usually reflects the average historical trend in the productivity of a group of peer utilities. A stretch factor (sometimes called a consumer dividend) is often added to the X variable to guarantee customers a share of the benefit of productivity growth that is expected to exceed the peer group norm due, for example, to the stronger performance incentives that are expected under the plan. Stretch factors are sometimes based in whole or in part on statistical benchmarking studies on the premise that poor (good) operating performances are capable of more rapid productivity growth.

Index-based 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, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging. Cost trackers may be needed to address capital revenue shortfalls. Design of indexed ARMs that apply to capital as well as O&M cost can involve statistical cost research that is complex and sometimes controversial.

Q. IS THERE PRECEDENT FOR USE OF INDEXED ARMS?

A. Yes. The index approach to ARM design has been extensively used to regulate U.S. railroads, telecommunications carriers, and oil pipelines. A price cap index was used in an MYP of Qwest in Colorado. Indexed ARMs have also been used to regulate several gas and electric utilities in California and New England. O&M revenue requirement escalators have also been used for many years by gas and electric utilities in Vermont.[27] Outside the U.S., indexed ARMs have been used several times by regulators in Canada and New Zealand to regulate energy utilities. The Régie de l'Energie has ordered Hydro-Québec and Gaz Métro to operate under indexed ARMs prospectively.

Q. WHAT IS THE FORECAST APPROACH TO ARM DESIGN?

A. A forecasted ARM is based on multiyear 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 chiefly on mechanistic depreciation. The focus of a proceeding to approve a capital cost forecast is instead on the value of plant additions during the plan. The Commission and customer organizations have an opportunity to weigh in on the utility's business 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. Yet rate trajectories can be still be smoothed to reduce rate bumps. 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.

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[27] Capital cost is subject to COSR in these Vermont plans. Hence, I do not consider them to be MYPs.

On the downside, forecasted ARMs do not protect utilities from unforeseen growth of input prices and operating scale. It can be difficult for regulators to identify just and reasonable multiyear cost forecasts. It can also 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. Shortcuts are sometimes taken in preparing forecasts for ARM design. This can simplify the preparation and review of forecasts and reduce the discretion of the forecaster. In California MYPs, for instance, forecasted plant additions are sometimes set at the utility's average value in recent years,[28] or at its value for the test year of the rate case.

The Ontario Energy Board asks utilities to base forecasted ARMs on productivity and cost benchmarking research.[29] Regulators in Britain and

[28] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[29] The Board, additionally, requires power distributors to use econometric benchmarking to appraise their proposed revenue requirements in forward test year rate cases.

Australia have commissioned their own benchmarking and engineering 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.[30] O&M revenue is indexed, while 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 customer growth) 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. Indexes of prices for materials and services that energy utilities use are maintained by Global Insight.

The forecast approach to capital revenue, meanwhile, accommodates diverse capital cost trajectories. Rate 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.

[30] A “hybrid” designation can in principle be applied to other ARM design methods, including the method used in Great Britain.

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

A variant on the hybrid theme is to forecast O&M expenses using index-based formulas like that in relation [2]. This approach has been used several times in California and Australia and was used to develop the ARMs in the current MYPs for gas and electric services of Puget Sound Energy.

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

A. Some MYPs feature a rate freeze in which the ARM provides no rate escalation during the plan. This is sometimes combined with one or more trackers for rapidly growing costs. 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. This approach is currently used in the regulation of the Company's electric services. Other VIEUs that have operated under tracker/freeze mechanisms include Arizona Public Service, Central Louisiana Electric Co-Op, Florida Power and Light, and Virginia Electric and Power.

B. <u>Earnings Sharing</u>

Q. PLEASE DISCUSS THE EARNINGS SHARING PROVISIONS OF MYPS.

A. ESMs share earnings variances that arise when a utility's ROE deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands 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.[31] 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 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 electric services of the Company.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[32] 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 such as inflation and customer indexing, Z factors, or revenue decoupling.

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[31] An ESM is therefore sometimes referred to as a “banded ROE.”
[32] This problem can be contained by sharing only the utility’s earnings surpluses.

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 current U.S. and Canadian MYPs.

C. Efficiency Carryover Mechanism

Q. HOW DOES AN EFFICIENCY CARRYOVER MECHANISM WORK?

A. An Efficiency Carryover Mechanism ("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 is used to establish rates for the first year of the next plan. Performance is typically established by comparing the revenue requirement to a benchmark. The benchmark can be based on statistical benchmarking or the ARM from the expiring MYP.[33]

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,

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

Australia, and Ontario. The Ontario Energy Board uses an econometric benchmarking model to appraise the total costs of most provincial power distributors in every year of the MYP period. My company developed and annually updates this model. Superior cost performers are assigned lower X factors in their price cap indexes. Sustainable cost reductions achieved in one plan can therefore produce higher earnings in future plans.

III. AN APPRAISAL OF THE COMPANYS MYP PROPOSAL

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

A. Key provisions of the Company's proposed plan are summarized in Figure MNL-D-9. The plan would establish terms of service for the three calendar years 2018 through 2020. The ARM would escalate rates, not revenue. Rates would rise uniformly each year by percentages set in advance, which are determined with hybrid methods. Escalation of the revenue requirement for

Figure MNL-D-9 Summary of the Proposed Gas MYP

Basic Approach to Incentive Regulation	Multiyear Rate Plan
Revenue Caps or Price Caps	Rate Caps
Relaxing the Revenue/Usage Link	LRAM
Attrition Relief Mechanism	Hybrid
Y Factors	Gas supply and upstream transmission (GCA), damage prevention, property taxes, pension benefits, pipeline system integrity (2018 only)
Z Factors	Yes
Performance Incentive Mechanism	Safety Customer Service Demand-side management
Earnings Sharing Mechanism	Yes
Marketing Flexibility	Yes
Plan Term	3 years

capital cost would be based on a conventional forecast. Escalation of labor cost revenue would be 2 percent in each plan year. The revenue requirement for non-labor expenses would be frozen. The revenue requirements for property taxes and regulatory amortizations would be sculpted to smooth rate growth. The pipeline system integrity adjustment ("PSIA") tracker would expire after 2018, making rates more predictable. The plan would also include an ESM called an earnings test.

Tracker treatment is proposed for some cost categories.

- Gas supply and upstream transmission (Gas Commodity Adjustment)
- Damage prevention
- DSM
- Property taxes
- PHMSA regulations
- Pipeline System Integrity (in 2018 only)
- Pensions

Z factor treatment is proposed for changes in generally-accepted accounting principles, tax laws, or federal, state, or municipal laws or regulations. 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 gas 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 gas service quality. There are PIMs for meter reading errors and the time to complete permanent repairs on recorded leaks. The QSP for electric services already addresses several aspects of the Company's customer service quality. The proposed Enhanced Emergency Response Program also contains a performance metric.
- Public Service has a LRAM and a performance incentive mechanism for its gas DSM program.

- The Company has some flexibility in the marketing of gas services. The Flexible Pricing Policy is sanctioned by Colorado statue.[34]
- 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 proposal. The particular package of provisions the Company is proposing is unique, as in any plan, but very much in the mainstream of MYPs in use today. There is no efficiency carryover mechanism, but these are not yet the norm in MYP design.

The general approach to ARM design proposed by Public Service is widely used.[35] Basing capital revenue on a forecast is not a radical departure from current ratemaking. Rate growth is smoothed. Capital cost forecasts usually play some role in ARM design when capex is high. Public Service has demonstrated the value of its proposed revenue requirements by filing extensive planning evidence and by commissioning the benchmarking and indexing work I am presenting in this testimony. Supportive statistical research is recommended for forecasted ARMs but rarely undertaken by North American utilities. The Company's funding of this 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 ESM that Public Service proposes is unusual in that

[34] See Colorado Revised Statutes, Section 40-3-104.3.
[35] A comprehensive indexed ARM may merit consideration in future plans for the Company's gas services.

it 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 plans have a deadband in which the utility keeps 100 percent of small earnings surplus. Public Service proposes instead that customers have a share in *all* earnings surpluses. The strong customer protection provided by the earnings test should further reduce concern that the proposed revenue requirements are too high.

The three-year period of the proposed plan is shorter than many, but this is common in first-generation plans. The MYPs that the Commission has approved for electric services of Public Service have also had three-year terms.

DSM is encouraged by a performance incentive mechanism, an LRAM, and the tracking of the Company's DSM expenses. Revenue decoupling merits consideration for residential and commercial customers in future plans. Decoupling removes disincentives for the Company to embrace a wider range of DSM initiatives. The proposed price caps incentivize the Company to make its services to large volume customers more responsive to their needs.

Q: WHAT IS THE OUTLOOK FOR THE COMPANY'S GAS REGULATION IF AN MYP IS NOT APPROVED?

A: I explained in Section 2 of my testimony that business conditions facing LDCs today are less favorable than in the golden age of COSR. In particular, average use by residential and commercial customers is trending downward, and capex that doesn't automatically produce revenue is often high. COSR today can thus involve frequent rate cases for LDCs, over a repetitive set of issues, and weak performance incentives. Public Service has in fact been filing frequent rate cases for its gas services and has an integrity management cost tracker. Due in part to historical test years, the Company has also been chronically under earning. This situation is likely to continue if an MYP is not approved.

IV. 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 undertook 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 revenue requirement forecast is an important consideration for the Commission in determining appropriate annual rate adjustments. Benchmarking can be used to appraise the proposed revenue requirements.

Statistical benchmarking uses statistics to establish benchmarks that can be used in quantitative cost performance appraisals. Utility operating data can be used to establish benchmarks for these appraisals. These data are available from reports that LDCs 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 historical costs and proposed revenue requirements during the plan using two statistical benchmarking methods: econometric modelling and unit cost indexing. We benchmarked the proposed revenue requirements for non-gas O&M expenses and total non-gas cost. Total cost was defined as non-gas O&M expenses plus capital costs. 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 gas supply and transmission by others, compressor station fuel, customer service and information, pensions and benefits, uncollectible bills, franchise fees, and taxes.[36]

Data used in the study were drawn from respected sources. The cost data were chiefly drawn from LDC reports to state utility commissions. These reports typically use FERC Form 2 as a template.

[36] Customer service and information expenses include costs of LDC DSM programs.

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. However, our statistical benchmarking also examined total costs, which matter the most to customers.

Q. PLEASE DISCUSS YOUR ECONOMETRIC BENCHMARKING METHODOLOGY.

A. Guided by economic theory, we developed models of the impacts that various business conditions have on the included non-gas O&M expenses and total non-gas costs of LDCs. The parameters of each model, which measure the impact of the business conditions on cost, were estimated statistically using historical data on utility operations. The econometric research was based on a sample of data for 33 U.S. LDCs. These are companies for which the good data needed for *total* cost benchmarking, as well as O&M benchmarking, are available. The sample includes more than 60 percent of the U.S. LDCs that, like Public Service, serve more than one million gas customers.[37]

The sample period for cost model estimation was 1998 through 2015. The sample has 594 observations and is large and varied enough to permit development of sophisticated cost models in which several drivers of LDC cost can be identified. All estimates of model parameters were plausible and most are

[37] Several large LDCs (e.g., Southwest Gas) have problematic data that could not be used.

statistically significant. Models fitted with econometric parameter estimates and values for the business condition variables which Public Service expects during the MYP generated benchmarks for their proposed revenue requirements.

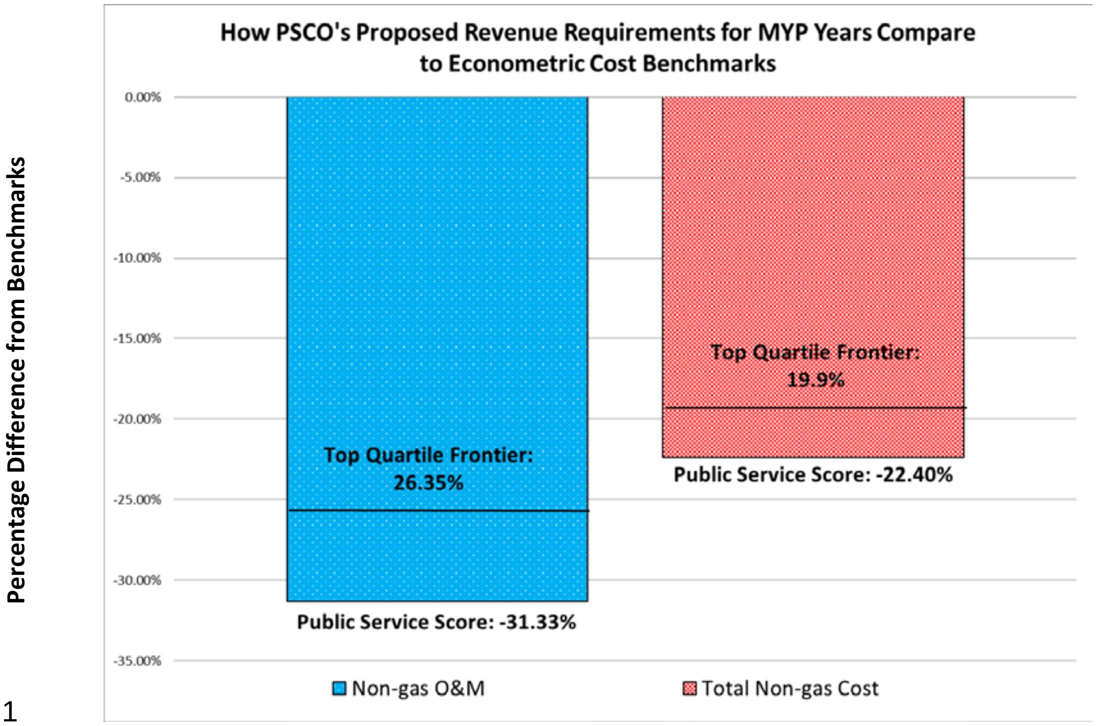
Q. WHAT ARE THE RESULTS OF YOUR ECONOMETRIC BENCHMARKING WORK?

A. The non-fuel O&M revenue proposed by Public Service is about 31 percent below the benchmarks generated by our econometric O&M cost model on average during the MYP years. This score is commensurate with a top quartile (specifically number seven) ranking. The proposed total non-gas revenue requirement is about 22 percent below the benchmarks generated by our total cost model on average. This score is also commensurate with a top quartile (specifically number seven) ranking. These results are depicted in Figure MNL-D-10.

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

A. We compared the Company’s proposed real (inflation-adjusted) unit non-gas O&M and total unit non-gas revenue during the MYP years to the corresponding unit costs of a peer group of six western LDCs in 2015. These LDCs had an operating scale that was slightly larger on average than that of Public Service. The proposed unit O&M revenue requirement for 2018 was about 42 percent below the peer group mean on average. This score is commensurate with a top

Figure MNL-D-10 Results of Econometric Benchmarking Work



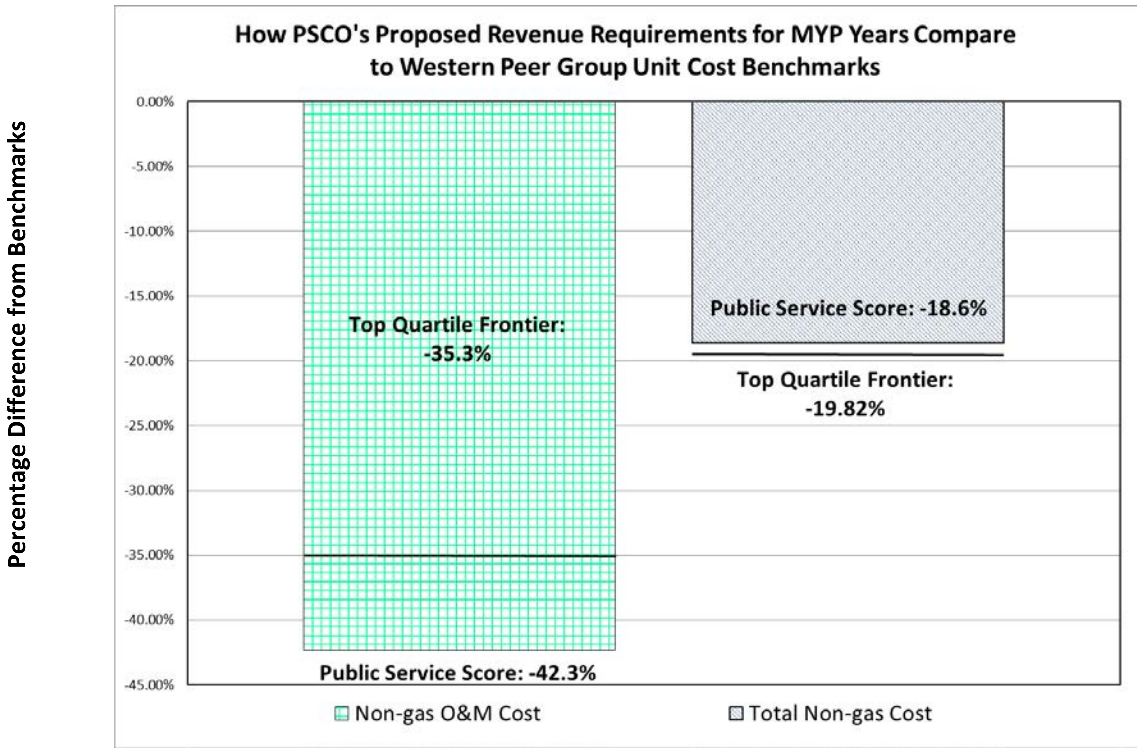
quartile (specifically number one) ranking. The proposed unit total non-gas revenue requirement was about 19 percent below the corresponding peer group means on average. This score is good despite a number four ranking among eight utilities because the unit cost performance of the companies ranked two, three and four are separated by less than 2%. The unit cost results are 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 revenue requirements during the MYP years offer customers good value. These findings are all the more remarkable when it is considered that the

Company has been obliged in recent years to incur sizable system integrity costs.

Figure MNL-D-11 Results of Unit Cost Benchmarking Work



B. <u>O&M Revenue Escalator</u>

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

A. We developed an O&M revenue escalator that is consistent with cost theory and regulatory precedent. This work used the same dataset on which our econometric benchmarking study is based. The formula for the escalator is

$$\textit{growth Revenue}^{O\&M} = \textit{growth Input Prices}^{O\&M} - X + \textit{growth Customers.}$$

Here the X variable is the 0.57 percent long-term trend in the O&M productivity of the 33 sampled LDCs.

From 2018 to 2022, the non-gas O&M input price index we used in the benchmarking work is forecasted to average 2.46 percent growth.[38] Public Service forecasts the number of its gas customers to average 1.11 percent annual growth. Given, additionally, the 0.57 percent non-gas O&M productivity trend, our O&M revenue escalator is forecasted to average 2.99 percent annual growth.

The Company forecasts growth in the part of the non-gas O&M revenue requirement that we benchmark to average 0.87% during the MYP period. The difference between the forecasted growth in our O&M revenue escalator and the growth which the Company proposes is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 2.12%. Approved stretch factors in indexed rate and revenue caps of North American energy utilities typically range between 0 and 0.60%. Thus, the proposed rate of O&M revenue requirement escalation is unusually slow.

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

V. IMPACT OF HISTORICAL TEST YEARS ON LDC 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 premise 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 the growth in real non-gas O&M expenses of LDCs. We found that real cost growth depends on growth in residential and commercial throughput. The throughput growth rates of sampled LDCs operating under historical and forward test years varied. We need to control for this phenomenon if we wish to identify the effect of the type 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, we found no tendency for real cost to grow more slowly for utilities operating in jurisdictions that use historical test years. 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. Under adverse business conditions, historical test years can prevent a full true-up of revenue to cost, but the incentive impact of this characteristic can be more than offset by the greater frequency of rate cases. Public Service is proposing an MYP in this proceeding that expressly limits rate case frequency.

VI. RECOMMENDATIONS

Q: DO YOU RECOMMEND THAT THE COMMISSION APPROVE THE MYP THAT PUBLIC SERVICE PROPOSES?

A: Yes. All in all, I consider this plan a sensible and prudent first step in the establishment of MYP regulation for the Company's gas operations.

Public Service has proposed a comprehensive MYP that is well within the mainstream of industry precedents. Customer protections are unusually strong. My empirical research found the proposed revenue requirement to offer customers good value. These results are remarkably favorable given the gas system integrity costs Public Service has had to incur in recent years.

Implementation of the plan is especially appealing in view of the fact that, under foreseeable business conditions, the alternative is a continuation of frequent gas rate cases. This alternative scenario is one of high regulatory cost, uneven and unpredictable rate growth, and weak performance incentives. I recommend that the Commission approve the proposed plan and stick with the MYP approach to gas service regulation in the years after this plan expires.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Mark Newton Lowry

Mark Newton Lowry is President of PEG 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. Multiyear rate plans and utility performance measurement have been his chief professional focus for almost three decades. He has testified dozens of times on MYPs, benchmarking, and productivity 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 natural gas utilities is a specialty. He has also benchmarked the reliability of electric utilities and the costs these utilities incur in power generation, transmission, distribution, and administrative and general services. He has 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 ("OEB"), 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 ("CEA") (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. He has published articles on his gas 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.

Dr. Lowry 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 (United States).

Multiyear rate plans are another of Dr. Lowry's specialties. He has testified on the MYP approach to regulation in numerous jurisdictions. He has for many years advised the Edison Electric Institute on MYPs and other forms of Altreg, preparing several surveys and white papers on Altreg. 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 of Mineral Economics at the Pennsylvania State University. His resume also includes numerous professional publications and speaking engagements. He has chaired several conferences on alternative regulation and utility performance measurement. A Cleveland, Ohio native, he attended Princeton University and holds a Ph.D. in Applied Economics from the University of Wisconsin – Madison (“UW”).