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

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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 SCOTT B. BROCKETT</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 2, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF THE DIRECT TESTIMONY OF SCOTT B. BROCKETT

Mr. Scott Brockett is Director, Regulatory Administration, for Xcel Energy Services Inc. (“Xcel Energy”). On an interim basis he is also serving as Regional Vice President, Rates and Regulatory Affairs. In these capacities he is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy.

Mr. Brockett is the Company’s primary regulatory policy witness in this Phase I rate case proceeding in which the Company is requesting Commission approval to: (1) implement a multi-year plan (“MYP”) for calendar years 2018, 2019, and 2020; (2) extend the current Quality of Service Plan for the gas department through the end of the MYP term; (3) defer certain types of expenses during the MYP period to the extent these expenses exceed the levels reflected in the MYP revenue requirements; (4)

update the Company's Charges or Rendering Service, and (5) eliminate the summation sheets from the gas tariff.

The requested incremental revenues the Company is requesting during the term of the MYP and the resulting General Rate Schedule Adjustments ("GRSA") are provided below:

Year	**Starting GRSA**	**Incremental GRSA**	**Total GRSA**	**Inc. Rev. ($)**	**Inc. Rev. – PSIA Roll-In ($)**
2018	17.12%	16.52%	33.64%	$63,195,261	$63,195,261
2019	33.64%	32.29%	65.93%	$126,826,936	$32,943,900
2020	65.93%	10.53%	76.46%	$42,915,002	$42,915,002
Total				$232,937,199	$139,054,163

After providing background information on the Company's customer base and scale of operations, Mr. Brockett turns to the MYP the Company is requesting. He explains that a MYP offers the benefits of:

- enhanced rate certainty,
- encouragement of more cost efficiency,
- reduced regulatory costs,
- more emphasis on and transparency into the Company's long-term planning,
- increased emphasis on important bottom-line metrics instead of line-by-line reviews,
- a fairer opportunity for the Company to earn its authorized ROE, and
- the facilitation of more gradual price increases.

He refers to the Direct Testimony of Dr. Mark Lowry of Pacific Economics Group Research, LLC ("PEG"), for a more complete review of MYPs in the U.S. and other countries and the common parameters of such plans, and an assessment of the Company's proposed MYP.

Mr. Brockett then explains why an MYP is particularly warranted for the Company's gas department. He documents the systemic and significant under-earnings of the gas department in recent years, despite the Company's fling of three Phase I rate cases since 2010 (with the instant proceeding being the fourth such filing), and charts the recent trends in key cost components and revenues. This history clearly demonstrates the need for forward-looking rate relief.

Mr. Brockett then turns to discussing the elements of the Company's proposed MYP. He explains that the proposed term of the plan is three years – the same MYP term approved for the electric department's MYPs.

Mr. Brockett also explains that the MYP revenue deficiencies are based on indexed O&M expenses and forecasted capital costs and revenues. He explains why the indices the Company proposes for O&M expenses incorporate significant levels of productivity improvements. He also explains that while the Company's MYP uses forecasted and indexed cost and revenues, these projections are grounded in historical information.

Mr. Brockett lists and explains the customer protections the Company is offering. The first is an Earnings Test under which the Company absorbs all under-earnings and retains 50 percent of any over-earnings up to 200 basis points above the authorized return on equity ("ROE"). Any earnings in excess of this threshold would be returned 100 percent to customers. The second protection is the extension of the Quality of

Service Plan ("QSP") for the gas department through 2020. In addition, Mr. Brockett explains the criteria by which rates would be adjusted to reflect significant cost changes outside of the utility's control, or "Adjustments for Material Changes to Expenses."

Mr. Brockett then explains that if the Commission approves the Company's proposed MYP, the Company will not seek to extend the Pipeline System Integrity Adjustment ("PSIA") beyond its current expiration date of December 31, 2018, and will commit to filing a Phase II rate case to readjust class cost responsibilities and base rates around the beginning of 2019.

Mr. Brockett also points out that the Company's MYP will allow the Commission and stakeholders more insight into the Company's long-term planning.

Finally, he explains that the Company's proposed MYP effectively limits the deferral of costs attributable to service today to future periods.

After addressing the specific elements of the Company's MYP, Mr. Brockett provides significant support for the use of forecasted or indexed costs and revenues in utility ratemaking. Specifically, he points out that using forward-looking cost and revenue projections better matched cost recovery with cost incurrence, provides a fairer opportunity for the utility to earns its authorized ROE, and maintains the Company's incentive to reduce costs and operate efficiently. Moreover, projections are reliable and can be reasonably reviewed by stakeholders.

Another litmus test of the reasonableness of the MYP is the reasonableness of the resulting rates. While line-by-line reviews are the typical test of reasonableness, an alternative, and in some ways more meaningful, test is benchmarking the resulting rates and costs against the market and against the Company's own rate history. To this end Mr. Brockett cites the statistical benchmarking studies the Company commissioned PEG to conduct. Mr. Brockett notes that PEG first conducted a statistical benchmarking study to compare the Company's costs under the proposed MYP with predicted costs for the same period – using a sample of 33 local distribution companies ("LDCs"). In his Direct Testimony Dr. Lowry summarizes this analysis and concludes that the Company's proposed costs demonstrate "first quartile" performance. PEG has also conducted a unit cost benchmarking study that confirms the Company's very good performance.

As another indication of the Company's good cost performance Mr. Brockett demonstrates that the Company offers some of the lowest rates for residential natural gas service in the country. He also shows that customer bills have decreased significantly over the last decade.

Based on PEG's benchmarking studies, rate comparisons and the Company's bill history, Mr. Brockett concludes that the Company offers customers an excellent price proposition.

Mr. Brockett then turns to the bill impacts of the Company's proposed MYP. He explains how the Company was able to use the extended test period afforded by the proposed MYP to "smooth out" bill impacts over the next three years – which promotes the traditional ratemaking goal of gradualism. Mr. Brockett provides the projected impacts of the Company's proposed MYP, as well as a second set of bill impacts that captures projected changes to all base rates and riders.

The projected bill impacts of the Company's proposed MYP on a typical residential customer and small commercial customer are provided below:

	2018 Impact		2019 Impact		2020 Impact	
	Dollars	%	Dollars	%	Dollars	%
Residential (RG)	$2.73	6.08%	$2.19	4.58%	$1.74	3.49%
Small Commercial (CSG)	$10.91	5.67%	$6.97	3.43%	$6.95	3.31%

Mr. Brockett then summarizes the HTY that the Company is providing for informational purposes and using as a starting point for the proposed MYP. Company witness Steven Berman discusses this HTY in more depth in his Direct Testimony. Mr. Brockett focuses this discussion on the Company's proposal to use year-end plant balances and amortize previously deferred costs over a relatively short period. He also lays out the Company's plan if the Commission approves an HTY in this proceeding. Specifically, the Company would be forced to file another rate case very soon after this proceeding concluded, seek an extension of the PSIA, and file for revenue decoupling.

In the next section of his testimony Mr. Brockett summarizes the drivers of the revenue deficiencies during the MYP. He demonstrates that these deficiencies are driven primarily by the fact that the Company's current rates are not compensatory (we are starting out with insufficient cost recovery today) and planned capital investments. Increases in O&M expenses and revenues have relatively less impact on the MYP deficiencies.

Mr. Brockett then offers some perspective on several cost-of-service inputs into the MYP costs of service that are sponsored and defended by other Company witnesses. These inputs include the requested ROE and capital structure, the proposed amortization of regulatory assets as of December 31, 2017, and the proposed return on regulatory assets and liabilities – including the prepaid pension asset. He also sponsors and explains the Company's position on the recovery of rate case expenses, the treatment of a gain on an asset sale, cost recovery of the Craig and Gunnison compressors, and the treatment of residential late-payment fees.

After explaining these cost-of-service inputs Mr. Brockett recaps the ongoing deferrals the Company seeks and why they are needed.

After covering the policy and technical aspects of the Company's prosed MYP, Mr. Brockett turns to administrative issues.

His first task is to explain and sponsor the tariff changes necessary to implement the Company's proposals in this proceeding.

In the next section of his testimony Mr. Brockett lists the compliance items stemming from the Company's previous Phase I rate proceedings and how the Company has complied.

Finally, he lists the specific approvals the Company seeks in this proceeding and recaps why the Company seeks approval of a MYP in this proceeding.

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DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

TABLE OF CONTENTS

SECTION **PAGE**

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2015 Phase I	Proceeding No. 15AL-0135G
AFN	Alternative Form of Notice
AGA	American Gas Association
AGIS	Advanced Grid Initiative and Security
ALJ	Administrative Law Judge
CAB	Cellulose Acetate Butyrate
CIP	Critical Infrastructure Protection
Commission	Colorado Public Utilities Commission
CLG	Large Commercial Sales Service
CPCN	Certificate of Public Convenience and Necessity
CRS	Customer Resource System
CSG	Small Commercial Sales Service
Department	Minnesota Department of Public Service
EOC	Energy Outreach Colorado
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GL	General Ledger

Acronym/Defined Term	**Meaning**
GRSA	General Rate Schedule Adjustment
Historical Test Year or HTY	Historical Test Year - 12 months ending December 31, 2016
IG	Interruptible sales service
LCDs	Local Distribution Companies
LPF	Late Payment Fee
MYP	Multi-Year Plan period of January 1, 2018 through December 31, 2020, which includes the 2018, 2019, and 2020 Test Years.
OCC	Office of Consumer Counsel
OPEB	Other Post-Employment Benefits
PEG	Pacific Economics Group Research, LLC
PHMSA	Pipeline Hazardous Materials and Safety Administration
PVC	Polyvinyl chloride pipe
PSIA	Pipeline System Integrity Adjustment
PTT	Productivity Through Technology
Public Service, or the Company	Public Service Company of Colorado
QSP	Quality of Service Plan
RG	Residential Service
ROE	Return on equity
SCADA	Supervisory Control and Data Acquisition

Acronym/Defined Term	**Meaning**
S&F	Service and Facility
TFL	Large Firm Transportation Service
TFS	Small Firm Transportation Service
TI	Interruptible Transportation Service
United Hydro	United Hydro Electric Company
WACC	Weighted Average Cost of Capital
WAM	Work Asset Management
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott B. Brockett. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. (“XES”) as Director, Regulatory Administration. XES is a wholly owned subsidiary of Xcel Energy Inc. (“Xcel Energy”), and provides an array of support services to Public Service Company of Colorado (“Public Service” or “Company”) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis. On an interim basis I am also serving as the Regional Vice President, Rates and Regulatory Affairs.

In my current roles I provide leadership, direction and technical expertise related to regulatory processes and functions for Public Service. I have testified on many occasions before the Colorado Public Utilities Commission ("Commission") on policy and technical issues. I describe my qualifications, duties and responsibilities in more detail in my Statement of Qualifications, which is set forth after the conclusion of my Direct Testimony.

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

A. I am testifying on behalf of Public Service.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I will first provide some background on the Company. I will then summarize the Company's requests in this proceeding and provide much of the policy justification for our positon. In addressing most issues I will rely in whole or part on the testimony of other Company witnesses. But I will also sponsor several of the Company's specific recommendations. A list of the issues I cover is provided below:

- Background on the Company's customer base, services, employment and price history.
- Reasons for the Company's requested rate increases and MYP.
- Summary of the Company's proposed MYP, including the term, use of cost indices and forecasts, earnings test, adjustments for material changes to expenses, termination of the Pipeline System Integrity Adjustment ("PSIA"), and commitment to file a Phase II proceeding within a specified period to realign customer rates.

- Merits of setting rates based on forecasts and indices rather than historical costs and revenues.
- Discussion of the reasonableness of the Company's proposed prices based on benchmarking metrics and studies, national price rankings, and projected customer impacts.
- Bill impacts based on both the Company's request in this proceeding only and the all-in bill impacts given projected changes all rates through 2020.
- Discussion of the Company's service quality.
- Summary of the 2016 Historical Test Year ("HTY") that the Company is providing in compliance with Decision No. R13-1307 in the 2012 Gas Rate Case (Proceeding No. 12AL-1268G). I also explain the other relief the Company would seek if the Commission approved a rate adjustment based on a single HTY.
- Drivers of the revenue deficiencies in 2018, 2019, and 2020.
- Summary and explanation of some of the cost-of-service and revenue inputs the Company proposes for the term of the MYP. These inputs include the capital structure, return on equity ("ROE"), and debt cost; the amortization of previously deferred costs; the return on the prepaid pension asset; rate case expenses; the treatment of gains/losses on asset sales; the cost of the Craig Compressor; and residential late-payment revenues. I highlight these specific issues because of their importance from either a policy or dollar perspective – or from both perspectives.
- Summary of the Company's proposal to defer for future collection expenses above base levels for property taxes, pension and benefits, Damage Prevention, and new pipeline safety regulations that may be promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA").

- Summary and introduction of the Company's proposed tariff changes to implement our requests in this proceeding.
- Company's compliance with requirements from prior rate cases.
- Company's requested approvals in this proceeding.
- Conclusions and summary.

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

A. Yes. I am sponsoring the following attachments:

- Attachment SBB-1: Comparison of Indexed O&M Expenses with WAM/GL O&M Savings
- Attachment SBB-2: Adjustments for Material Changes to Expenses
- Attachment SBB-3: American Gas Association ("AGA") Residential Gas Rate Comparison
- Attachment SBB-4: Bill Impacts of Company Proposed MYP
- Attachment SBB-5: All-In Bill Impacts
- Attachment SBB-6: Rate Case Expenses
- Attachment SBB-7: Atmos Bill Impacts – Craig Compressor
- Attachment SBB-8: Proposed Tariffs
- Attachment SBB-9: Ten Years of Capital Expenditures
- Attachment SBB-10: Ten Years of Customer Numbers and Use

Q. WHAT RECOMMENDATIONS ARE YOU OFFERING IN YOUR DIRECT TESTIMONY?

A. I recommend first that the Commission approve the Company's proposed MYP for the Gas Department through the year 2020. The proposed MYP would increase total retail customer bills by less than 6 percent in 2018, about 4.6 percent in 2019, and about 3.5 percent in 2020. As discussed in a later section of my Direct Testimony, the bill impacts in any given year will vary by type of customer.

Under this proposed MYP the Company would collect an additional $63.2 million of base revenue in 2018, an additional $127.0 million of base revenue above 2018 revenue in 2019, and an additional $42.9 million of base revenue above 2019 revenue in 2020. The proposed General Rate Schedule Adjustments ("GRSA") resulting from these increases are 33.64percent, 65.93 percent and 76.46 percent, respectively. These proposed GRSAs are designed to collect not only the additional base revenues require in each year, but also the deficiencies reflected in the current GRSA of 17.12 percent. The proposed GRSAs also capture the proposed elimination of the PSIA in 2019 and the concomitant transfer of cost recovery from the PSIA to base rates. The total requested base revenue request over the MYP period is $233 million, or $139 million net of the PSIA roll-in. These impacts are itemized in Table SBB-D-1 below:

Table SBB-D-1

Year	Starting GRSA	Incremental GRSA	Total GRSA	Inc. Rev. ($)	Inc. Rev. – Roll-In ($)
2018	17.12%	16.52%	33.64%	$63,195,261	$63,195,261
2019	33.64%	32.29%	65.93%	$126,826,936	$32,943,900
2020	65.93%	10.53%	76.46%	$42,915,002	$42,915,002
Total				$232,937,199	$139,054,163

In addition to these specific rate increases, I recommend the following;

- As part of the MYP, I recommend an Earnings Sharing Test and adjustments for material changes to expenses.
- I recommend certain adjustments to the amortization of previously incurred regulatory assets and the recovery of property-tax expenses to smooth out the bill impacts under the Company's proposal.
- I recommend that the Commission authorize the Company to defer for future recovery certain costs during the MYP period.
- I recommend that the Commission allow the PSIA to expire, except for the true-up of under- or over-collections through 2018, effective January 1, 2019.
- I recommend that the Commission approve an extension of the current Quality of Service Plan ("QSP") for the gas department through the entire MYP period – or through 2020.
- I recommend that the Commission allow the Company to split the gain resulting from a sale of utility assets near Georgetown, Colorado, equally between customers and shareholders.
- I recommend that the costs of the Craig and Gunnison compressors used to serve a Colorado LDC be recovered from the broad body of Public Service customers.

- I recommend updates to the Charges for Rendering Services.
- I recommend the elimination of the summation sheets.
- I recommend approval of the tariff changes required to implement the recommendations explained above.

II. COMPANY BACKGROUND

A. Overview of Xcel Energy and Public Service Company

Q. PLEASE PROVIDE AN OVERVIEW OF XCEL ENERGY.

A. Xcel Energy is the holding company parent of Public Service, and owns three other electric or electric and gas utilities: Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; and Southwestern Public Service Company. Xcel Energy also owns a small interstate pipeline company, WestGas Interstate, Inc. In total, Xcel Energy provides retail service in portions of eight states: Colorado, Minnesota, Texas, Wisconsin, New Mexico, North Dakota, South Dakota and Michigan. During the HTY and several years prior to that, the core utility business represented about 99 percent of Xcel Energy's total operating revenue. Xcel Energy has achieved efficiencies among the operations of its utility subsidiaries through XES, which is a centralized services company that provides and coordinates services and activities on an "at-cost" basis.

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE.

A. Public Service is a combination electric, gas, and thermal utility that is part of the Xcel Energy public utility holding company system. Public Service's gas department serves a wide variety of customers in the State of Colorado. Public Service both purchases gas for and delivers this gas to residential customers, as well as many businesses and other non-residential customers. These customers are often referred to as "sales" customers. Other non-residential customers purchase their own gas from third-party suppliers and arrange for Public Service to deliver this gas to their premises. These customers are generally referred to as "transportation" customers. They include not only our end-use transportation customers, but also Local Distribution Companies ("LDCs") to whom Public Service delivers gas. In turn, our LDC transportation customers distribute the gas delivered by Public Service to their own end-use customers.

Public Service also provides a small amount of gas transportation that is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). This jurisdiction occurs when Public Service delivers gas at interconnections with interstate pipelines for subsequent delivery outside of Colorado. This FERC-jurisdictional throughput accounted for only 0.05 percent of the Company's total throughput in 2016. The Company's testimony addresses only the Public Service intrastate gas business, which is subject to the Colorado Public Utilities Commission's jurisdiction.

Q. WHERE DOES PUBLIC SERVICE PROVIDE RETAIL GAS SERVICES WITHIN COLORADO?

A. The majority of Public Service's Residential gas sales (91.7 percent in 2016) are within the Front Range region and eastern Colorado. Other regions served include the Western Division, the San Luis Valley Division, and the Mountain Division. A map of Public Service's retail gas service territory is provided as Attachment CFC-1 to the Direct Testimony of Ms. Cheryl F. Campbell.

Additionally, Ms. Campbell provides a physical description of the Company's natural gas pipeline system.

Q. WHERE DOES PUBLIC SERVICE COMPANY RANK NATIONALLY IN TERMS OF THE SIZE OF ITS GAS OPERATIONS?

A. Public Service is the 8th largest provider of retail gas services in the United States in terms of number of customers, and 7th largest in terms of annual throughput.

B. <u>Customer Base</u>

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE'S CUSTOMER BASE.

A. Public Service provides almost all of its gas service under seven service schedules: Residential service ("RG"), Small Commercial sales service ("CSG"), Large Commercial sales service ("CLG"), Interruptible sales service ("IG"), Small Firm Transportation service ("TFS"), Large Firm Transportation Service ("TFL"), and Interruptible Transportation service ("TI"). RG and CSG customers constitute the vast majority of the Company's total customer base – about 99.4 percent in 2016. They also accounted for about 82.1 percent of the Company's base revenues in 2016.

But larger customers account for a much larger percentage of throughput. In fact, transportation customers accounted for almost 50 percent of total throughput in 2016. Table SBB-D-2 below provides the customer numbers, usage and base revenues for each of the seven service schedules in 2016.

Table SBB-D-2 2016 Customer Numbers, Usage and Base Revenues

Service Schedule	Number of Customers	%	Usage (therms)	%	Base Revenue (Excludes Rider Revenue)[1]	%
Residential (RG)	1,265,001	92.10%	908,424,309	37.44%	$242,934,859	62.71%
Small Commercial (CSG)	100,255	7.30%	317,361,027	13.08%	$75,277,852	19.43%
Large Commercial (CLG)	699	0.05%	53,574,564	2.21%	$6,009,440	1.55%
Interruptible (IG)	12	0.00%	4,674,720	0.19%	$125,790	0.03%
Sm Firm Transport (TFS)	5,560	0.40%	157,167,770	6.48%	$16,937,663	4.37%
Lg Firm Transport (TFL)	1,715	0.12%	812,964,020	33.50%	$39,705,100	10.25%
Interruptible Transport (TI)	205	0.01%	172,378,580	7.10%	$6,389,455	1.65%
Totals	**1,259,893**	**100.0%**	**2,426,310,654**	**100.0%**	**$387,405,731**	**100.0%**

C. Investment and Employee Base

Q. IS PUBLIC SERVICE A LARGE EMPLOYER AND TAXPAYER IN THE STATE OF COLORADO?

A. Yes. The Company's Gas Department employs about 800 part-time and full-time employees. The vast majority of these employees reside in Colorado. The Gas Department has also invested heavily in Colorado. At the end of 2016 the Company's gross gas plant was about $3.6 billion and our net plant was about 2.5 billion. In addition, the Company also pays the most property tax of any business in Colorado. Public Service Company paid about $165.9 million of

[1] The revenues provided in this table are gross billed revenues and have not been weather normalized.

property tax in 2016, of which about $34.9 million was attributable to the gas department.

III. POLICY BASIS FOR REQUESTED MYP

Q. WHY IS THE COMPANY REQUESTING AN MYP IN THIS PROCEEDING, RATHER THAN A RATE INCREASE BASED ON A SINGLE HISTORICAL TEST YEAR OR FORWARD TEST YEAR ("FTY")?

Q. The Company believes that setting rates based on a longer-term view of the Company's business benefits customers and merits serious consideration as a long-term ratemaking policy in Colorado. In other words, we believe MYPs are generally in the public interest. There is often a natural reluctance to depart from traditional ratemaking practices. Yet well-designed MYPs can maintain the protections of rate cases based on reviews of single test years while offering several important improvements over this more traditional approach. The degree to which MYPs are superior to rates based on a single test year varies over time and among utilities. But in this particular proceeding the Company believes the advantages of an MYP to customers and the utility are very apparent and very significant.

Q. ARE MYPS NEW TO COLORADO?

A. No. The Commission has already approved two MYPs for the Company's electric department. The Company's electric department has been operating under MYPs since 2012.

Q. WHAT ARE SOME OF THE POLICY ADVANTAGES OF MYPS?

A. One key advantage is rate certainty to customers. Under MYPs customers are assured of what their rates for base service will be, which helps them budget for their energy expenses. Admittedly, customers continue to pay riders or rate adjustments that are not fixed during the term of an MYP. Fortunately, MYPs can also facilitate the elimination of riders by recognizing projected changes to certain costs over multiple years. This proceeding provides a perfect example: The Company is not proposing an extension to the PSIA if the Commission approves an MYP that addresses forecasted changes to our costs of integrity investments. By shifting more cost recovery to predetermined base rates the Commission can achieve even more rate certainty through MYPs.

A second advantage is that MYPs encourage the utility to operate more efficiently through longer regulatory lag. In the absence of MYPs with stay-out provisions, a utility can choose to file rate cases as frequently as it wants – even annually if rates fail to keep pace with the utility's cost growth. This scenario is not always an indication that the utility is operating inefficiently, as traditional regulation with its emphasis on historical costs and test years often results in rates that are outdated even on the day they are implemented – leaving no good alternatives to frequent rate filings. But by committing to operate with predetermined rate increases for several years the utility can no longer rely on frequent rate cases to address under-earnings and has a stronger incentive to pursue cost savings and operate efficiently. Customers then benefit through lower rates.

A third advantage is reduced regulatory costs. Rate cases impose significant resource requirements on the Commission and regulatory stakeholders – as well as the utility. Reducing the frequency of rate cases can free up some time for the Commission and all stakeholders to focus on other important policy matters. Even lengthening the time between rate filings by one year offers significant resource relief.

A fourth advantage is one that is perhaps under-appreciated. When a rate case focuses on costs and revenues during a single test year, there is little opportunity to evaluate a utility's long-term business plans and determine if they conform to the Commission's vision. Using a single historical test year exacerbates this problem -- as the focus is almost exclusively on what has happened rather than what will or should happen over the next few years and beyond. Part of what the Company hopes to accomplish through MYPs is to provide the Commission and stakeholders with more transparency into our business and financial plans. In effect, they have a seat at the business planning table and can engage in more in-depth and engaged reviews and oversight than has traditionally been the case.

This focus is apparent in the Direct Testimony of Company witnesses in this proceeding. For example, Ms. Campbell addresses several planned distribution upgrades to serve our long-term needs. In the process she also explains how we evaluate our capacity needs. Mr. Litteken offers a similar long-term assessment of our efforts related to damage prevention and emergency response. Mr. Brossart explains the long-term net benefits of our General Ledger ("GL") and Work Asset Management ("WAM") investments. Ms. Schell explains our long-term outlook regarding maintaining financial integrity and strong credit metrics.

The Company is not proposing that the Commission be forced to micro-manage every aspect of our business; we have the obligation to develop business plans and attend to the day-to-day operations of the business. But we do believe the Commission should have the opportunity to direct or advise us on important long-term initiatives before resources are committed to these initiatives.

A fifth advantage is that MYPs can facilitate a greater focus on bottom-line results than the more traditional approach of scrutinizing many discrete cost and revenue elements on a line-item basis. This advantage may also be under-appreciated. Customers care primarily about bottom-line bills, service quality and safety. One important feature of MYPs is that they tend to rely on indexing to various degrees to achieve reasonable results. This is an important change in emphasis. While traditional regulation has focused on a utility's actual or projected costs, indexing takes us down the road of limiting rate increases to levels that make sense in the context of a broader market – as represented by an index. In effect, indexing represents a modest step towards reflecting outcomes more like those obtained in competitive markets.

A sixth advantage is that MYPs can provide a fairer opportunity for the utility to earn its authorized return, while also retaining the incentives of relatively low returns for bad performance and relatively high returns for superior performance. While there is certainly disagreement about how to implement economic regulation, one principle commonly agreed to is that rates during any given period should reflect conditions during that same period. MYPs allow for rate adjustments to reflect changes from year-to-year without guaranteed earnings and without frequent rate cases.

The extent to which traditional regulation fails to provide a utility with a fair opportunity to earn its authorized returns depends on the relative changes to costs and revenues after the test year. For example, using HTYs rather than FTYs certainly exacerbates the problem. Yet the important issue is not whether traditional regulation does a better job under certain conditions; well-designed MYPs will be better under virtually all conditions. What changes is simply the extent to which MYPs are superior.

As I explain in more detail below, conditions today render traditional regulation less effective for our gas department. Specifically, we are facing increasing costs and flat or slightly increasing revenues. Under those conditions, an MYP makes even more sense.

A seventh advantage is that MYPs afford some additional flexibility for mitigating or smoothing out rate increases over a longer period. In fact, in this proceeding the Company is proposing to mitigate the first- and second-year bill impacts under the MYP.

Q. ARE MYPS A NEW IDEA?

A. No. Many jurisdictions across the country have approved MYPs for energy utilities. As I noted previously, the Company has operated under an MYP for its electric department in Colorado since 2012. MYPs are even more common in other countries. MYPs have also been used in other industries – such as telecommunications.

For this proceeding the Company engaged a national expert on utility regulation – Dr. Mark Lowry of Pacific Economics Group ("PEG") – to provide some background on the use of MYPs and how they are typically designed. Dr. Lowry explains that they have been used frequently and their use is growing.

Q. HAVE ANY OF XCEL ENERGY'S OTHER OPERATING UTILITIES OPERATED UNDER MYP COMPACTS?

A. Yes. Northern States Power Company – Minnesota has operated under MYPs in Minnesota and North Dakota.

IV. NEED FOR MYP IN THIS PROCEEDING

Q. WHY IS AN MYP PARTICULARLY WARRANTED FOR THE COMPANY'S GAS DEPARTMENT UNDER CURRENT CONDITIONS?

A. As illustrated in Table SBB-D-3, the Company has experienced systemic under-earnings over the past 20 years. Since 1997 the Company has earned less than its authorized return on equity in 16 years and earned more than its authorized return in only 4 years.

Table SBB-D-3 Earned vs. Authorized ROE

Year	Authorized ROE (%)	Appendix A ROE %)	Delta (Basis Points)
1997	11.25%	9.07%	-218
1998	11.25%	6.74%	-451
1999	11.25%	8.42%	-283
2000	11.25%	11.06%	-19
2001	11.25%	10.60%	-65
2002	11.25%	11.94%	69
2003	11.00%	12.22%	122
2004	11.00%	8.76%	-224
2005	11.00%	7.00%	-400
2006	10.50%	7.79%	-271
2007	10.25%	10.14%	-11
2008	10.25%	11.37%	112
2009	10.25%	10.77%	52
2010	10.25%	9.16%	-109
2011	10.10%	8.78%	-132
2012	10.10%	7.23%	-287
2013	9.72%	9.01%	-71
2014	9.72%	7.59%	-213
2015	9.50%	6.04%	-346
2016	9.50%	6.47%	-303

Furthermore, the rates based on the authorized returns provided above exclude a wide variety of costs that the Company does not recover based on statutes or Commission precedent. For example, 91 percent ($581,000) of corporate aircraft and $926,000 of advertising expenses were removed from 2016 expenses. Similarly, the derivation of the earned returns also exclude these costs. Our authorized and earned returns would be much lower if those costs were recognized. Company witness Steven P. Berman provides a list of these adjustments in his Direct Testimony.

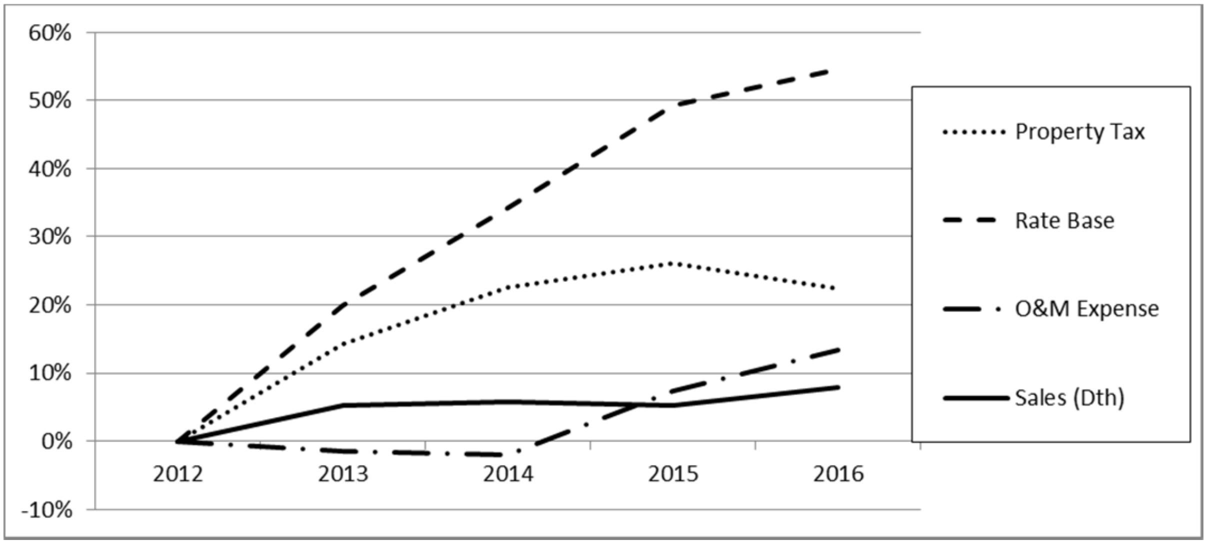
Q. IS THE COMPANY'S RECENT EXPERIENCE CONSISTENT WITH THIS LONG-TERM TREND?

A. Yes. Over the past five years the Company has earned on average 244 basis points less than its authorized return.

Q. WHY HAVE EARNINGS BEEN SO LOW?

A. The main reason is that we are facing increasing costs and flat or modestly increasing sales. Figure SBB-D-1 depicts our percentage growth in rate base, property taxes, O&M expenses, and customer usage from 2012 through 2016 – excluding costs recovered through the PSIA and PSIA revenue. We have clearly experienced consistent cost increases with very little revenue relief. Over this same period our rates have been based on HTYs with limited known and measurable changes. In fact, our current rates are based on an 2016 HTY using average rate base for the test period. When costs are increasing faster than revenues, rates based on HTYs are not compensatory.

Figure SBB-D-1



Q. ARE THE UNDER-EARNINGS SIMPLY A REFLECTION OF THE COMPANY'S FAILURE TO CONTROL COSTS AND OPERATE EFFICIENTLY?

A. No. The evidence suggests otherwise. I will address our performance in more depth later in my testimony. But our rates are very low by national standards and have remained relatively flat over time. We have maintained these relatively low rates even in the face of significant integrity initiatives. The benchmarking studies that we commissioned PEG to conduct reinforce the conclusion that we operate very efficiently and offer customers low prices for the services we provide. Dr. Lowry sponsors this study, and I will refer to it later in my testimony.

Q. WERE THE COSTS OF THE INTEGRITY INITIATIVES THE SOURCE OF THE UNDER-EARNINGS?

A. No. During each of the past five years we recovered the costs of our incremental integrity initiatives (except for the 2016 O&M expenses) on a current basis through the PSIA. Integrity work was not a driver of the under-earnings.

Q. WERE THE UNDER-EARNINGS A RESULT OF THE COMPANY'S FAILURE TO SEEK TIMELY RATE RELIEF?

A. It is difficult to reach this conclusion. The Company filed Phase I rate cases in December 17, 2010, December 12, 2012, and March 3, 2015, with final or provisional rates effective September 5, 2011, August 10, 2013 and October 1, 2015, respectively. Admittedly, the Company could have filed rate cases every year. But even annual cases would not have adequately addressed the issue if HTYs were used. For example, we earned well below our authorized ROE in both 2012 and 2016, even though rates from Phase I proceedings were implemented around the beginning of each year. More important, if the only remedy was annual rate cases, then that sad solution suggests a more fundamental ratemaking problem. I do not believe any stakeholder supports a strategy of annual rate cases.

V. MYP PROPOSAL FOR 2018 – 2020

A. Overview

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED MYP?

A. We tried to account for and balance a wide variety of goals and criteria. Some of the most important goals and criteria are listed below;

- The MYP should be conservative, since MYPs are not yet the norm in Colorado.
- The term should reflect a balance – that is, be sufficiently long to obtain the desired efficiency incentives of MYPs while recognizing the need to limit the term of the plan given that it will be the first MYP for the gas department.
- The MYP should include a movement towards using indexing and benchmarking.
- The plan should include customer protections that prevent extreme over-earnings or a degradation in service quality or safety.
- The proposed rates under the plan should be reasonable and reflect the costs incurred by an efficient utility.
- The proposed rates under the plan should not result in extreme bill impacts.
- The testimony supporting the plan should explain our long-term business planning and major initiatives and why they benefit customers.
- The plan should protect both customers and shareholders by including adjustments for material changes to expenses to capture significant changes to costs outside of the utility's control.
- The plan should be informed by the MYPs approved for our electric department.

With these criteria in mind, I will cover the following elements of the proposed MYP in order: duration of plan, basis for schedule of GRSA increases, customer protections, adjustments for material changes to expenses, commitment to file a Phase II rate case, socialization of the Company's long-term business plans, elimination of the PSIA, and minimization of impacts on rates after the MYP period.

B. <u>Plan Term</u>

Q. WHAT PERIOD DOES THE COMPANY'S PROPOSED PLAN COVER?

A. The plan covers the three years from 2018 through 2020.

Q. WHY DID THE COMPANY CHOOSE THREE YEARS?

A. We tried to balance the goal of being conservative (limit the term of the plan) with the goal of encouraging efficient operations (lengthen the term of the plan). Given that the two MYPs for our electric department were both for three-year terms, we decided to offer three years for the gas MYP as well. As Dr. Lowry explains in his testimony, three years may be on the short end of a reasonable range of plan terms. Nonetheless, he believes that three years is a reasonable term for the initial MYP. The terms of future MYPs could be extended to four or five years.

C. Proposed Test Year Costs, Revenues and Rate Increases

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED O&M EXPENSES, CAPITAL COSTS AND REVENUES FOR THE 2018, 2019, AND 2020 TEST YEARS?

A. For most categories of O&M expenses, we applied an index to actual or adjusted 2016 expenses to derive the test-year amounts in 2018, 2019, and 2020. We forecasted two types of O&M expenses: Enhanced Emergency Response expenses, and pension and benefits expenses. We are also imputing the 2016 level of Damage Prevention expenses in the 2018, 2019, and 2020 test years, and are seeking a deferral of actual Damage Prevention expenses below or above this level. These three expense types tend to be more volatile and less amenable to indexing. Mr. Litteken discusses Damage Prevention and Enhanced Emergency Response expenses in his testimony, while Mr. Wickes and Mr. Schrubbe discuss pension and benefits expenses.

We used forecasts to derive test-year revenues and non-O&M costs in 2018, 2019, and 2020.

Q. WHY IS THE COMPANY PROPOSING TO USE INDEXED O&M EXPENSES AND FORECASTED CAPITAL COSTS AND REVENUES?

A. As mentioned earlier and consistent with Dr. Lowry's observations, the Company wants to use indices where they make sense. On the other hand, we want to be cautious in how quickly we move down the road to using indices. rather than historical or budgeted costs. Our O&M expenses are a good candidate for indexing. Although they are still affected by increases in input prices such as wage rates and salaries, they are becoming less volatile.

In contrast, while our capital expenditures are not demonstrating extreme fluctuations from year to year, our capital costs are increasing at relatively high rates due to significant integrity and non-integrity initiatives. As a result, our total capital costs do not necessarily follow trends in input prices and customer growth that might be captured through indices based on historical trends in capital expenditures or other metrics. Even if the Company is paying the same prices for mains or services or spare parts, the amount of investment in these plant items in increasing. Dr. Lowry discusses the challenges with capital costs in his Direct Testimony.

While revenues are generally less volatile than capital costs, the Company ultimately decided to propose forecasted revenues instead of revenues based on historical trends or a future-looking index. This approach eliminates the need to propose and vet a decoupling mechanism in the context of this proceeding – which already involves multiple policy issues. We believe our forecasts, as presented by Ms. Marks, are very reliable and serve as a solid basis for test-year revenues in this initial gas MYP. This approach does not disadvantage customers. In fact, Ms. Marks is actually forecasting higher sales growth in 2018 and 2019 than would be suggested by historical trends.

In the future we would be amenable to revenue decoupling based on changes in use per customer for at least the residential and small commercial customers if that were the Commission's preference. Revenue true-ups for other classes might also be workable if the true-ups were calibrated to projected revenues and not historical revenues.

Q. DOES THE COMPANY HOPE TO USE INDICES MORE EXTENSIVELY IN FUTURE PLANS?

A. Yes. The extent to which the greater use of indices is possible or desirable is a matter for future proceedings. But as a long-run policy the Company does believe that the increased use of indices is probably warranted if the Commission decides to rely more on MYPs.

Q. HOW DOES THE COMPANY PROPOSE TO DERIVE ITS INDEX-BASED O&M EXPENSES FOR 2018, 2019, and 2020?

A. The Company is using actual or adjusted O&M expenses in the 2016 HTY as the baseline level. (These baseline amounts exclude the four categories of O&M expenses for which we propose to use forecasts.) We then escalate these expenses to derive 2018, 2019 and 2020 expenses.

Q. HOW DID THE COMPANY DERIVE ITS PROPOSED INDICES?

A. The Company first directed PEG to derive an O&M index based on PEG's experience with indices typically used in MYPs. PEG's derived index of 2.99 percent is based on an O&M price input price index of 2.46 percent, plus projected customer growth of 1.11 percent, minus a productivity adjustment of 0.57 percent. Dr. Lowry explains this index in more depth in his Direct Testimony and Attachments.

Q. DOES THE COMPANY PROPOSE TO USE THE INDEX PEG DERIVED?

A. No. The Company is proposing a lower index to reflect our concerted efforts to manage O&M expenses through Productivity Through Technology ("PTT") and other initiatives. Such downward adjustments are often referred to as "stretch factors."

Specifically, the Company proposes to apply an annual index of 0.0 percent to non-labor expenses and 2.0 percent to labor expenses. The resulting stretch factors are 0.99 percent for labor expenses and 2.99 percent for non-labor expenses. We believe these are very aggressive stretch factors that capture our planned productivity improvements.

Q. WHY IS THE COMPANY PROPOSING TO HOLD NON-LABOR O&M EXPENSES FLAT AT 2016 LEVELS?

A. The Company is striving to limit growth in O&M expenses. While O&M expenses increased by an annual average of 5.71 over the past 10 years, the average annual increase over the past five years declined to 2.71 percent. The Company believes it can further reduce the growth in O&M expenses through WAM, GL and other productivity improvements. For this reason the Company is willing to live with an assumption of no growth in non-labor O&M expenses through 2020. We are committing to this limitation despite the fact that customer growth is expected to exceed 1 percent annually over this same period.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED ANNUAL ESCALATION FACTOR OF 2 PERCENT FOR LABOR O&M EXPENSES?

A. Some increase in labor costs is inevitable if the Company is to maintain our compensation packages at competitive levels. (See the Direct Testimony of Company witness Ms. Sharon Koenig.) But we believe we can partially offset wage and salary increases and higher customer numbers through efficiency gains beyond what PEG believes is typical for the industry. For that reason we are proposing a stretch factor of 0.99 percent when applied to the escalator that PEG derives.

Q. IS THE WEIGHTED AVERAGE OF THESE PROPOSED ESCALATORS REASONABLE?

A. Yes. Non-labor expenses account for about 56 percent of the entire pool of labor and non-labor expenses being escalated. Consequently, the weighted escalator is 0.87 percent. In short, we are proposing aggressive stretch goals for ourselves by assuming that our expenses will increase by less than the growth in the number of customers served.

Q. DO THE COMPANY'S PROPOSED O&M ESCALATORS CAPTURE THE ANTICIPATED SAVINGS IN O&M EXPENSES FROM THE WAM AND GL INVESTMENTS THAT MR. BROSSART DISCUSSES?

A. Yes. Absent any productivity adjustment or stretch factors, the Company would have applied PEG's derived price escalator adjusted for customer growth. That escalator is 2.46 percent plus 1.11 percent, or 3.57 percent. If we escalated our

HTY O&M expenses at this rate (first netting out the expenses to which the O&M indices do not apply), the 2018, 2019 and 2020 O&M expenses would be higher than our proposed expenses using escalators of 0.0 percent and 2.0 percent. These annual differences represent the total efficiency gains (productivity adjustment and stretch factor) embedded in our proposed O&M indices.

For each year, I compared these O&M efficiency gains with the projected O&M savings from the implementation of WAM and GL. For each of the test years the efficiency gain exceeds the projected O&M savings from WAM and GL. The specific differences between the O&M efficiency gains and the O&M savings from WAM and GL gains are $88,000 in 2018, $4.3 million in 2019 and $11.5 million in 2020. The derivations are provided in Attachment SBB-1

Q. ARE YOU SUGGESTING ANY CHANGES TO LIMIT OR "SHAPE" THE GRSA INCREASES RESULTING FROM THE APPROACH YOU OUTLINED ABOVE?

A. Yes. We are always concerned about the impact of requested, necessary rate increases on our customers. Consistent with the regulatory principle of gradualism, we consider ways to mitigate increases where possible and appropriate. In this case we concluded that while the bill impacts in 2020 were reasonable without any mitigation, the bill increases in 2018 and 2019 for the typical RG and CGS customer would be too high. Through the mitigation measures explained below we were able to limit the bill impact on the typical residential and small commercial in any one year to around 6 percent.

Q. HOW DO YOU PROPOSE TO ACHIEVE THIS MITIGATION?

A. The Company proposes two mitigation measures. The first is to modify the amortization of regulatory asset balances as of December 31, 2017. In the past the Company has used an amortization period equal to the projected period between rate cases -- or based on our MYP proposal a period of 35 months. But to reduce the 2018 rate impacts the Company proposes to begin the amortizations later and shorten the amortization period to 24 months to coincide with the end of the MYP period.

The second mitigation measure is to impute property taxes for the 2018 test year at 2016 levels, and collect the difference between 2016 actual property tax and 2018 forecasted property tax in 2020.

The net impact of these adjustments is to decrease the 2018 revenue requirement by $10.8 million, decrease the 2019 revenue requirement by $5.4 million, and increase the 2020 revenue requirement by $16.2 million. The shift in cost recovery from 2018 to 2019 to 2020 smooths out the total rate increase over the three-year period. These impacts are summarized in Table SBB-D-4 below:

Table SBB-D-4

Amortization Schedule						
	Deferred Balance as of 12/31/17	***Time Period***	***Start Date***	***2018 Annual Total***	***2019 Annual Total***	***2020 Annual Total***
Work Asset Management Capital Costs	2,630,188	24 Months	1/1/2019	0	1,315,094	1,315,094
Property Tax - Actuals vs Approved Amount	12,661,799	12 Months	1/1/2020	0	0	12,661,799
Emergency Response	6,006,234	24 Months	1/1/2019	0	3,003,117	3,003,117
Damage Prevention	2,913,447	24 Months	1/1/2019	0	1,456,724	1,456,724
Rate Case Expenses	1,073,682	24 Months	1/1/2019	0	536,841	536,841
Boulder MGP	50,839	24 Months	1/1/2019	0	25,419	25,419
Property Tax - 2018 Forecast vs. 2016 Actuals	8,977,128	12 Months	1/1/2020	0	0	8,977,128

D. Customer Protections

Q. PLEASE EXPLAIN THE CUSTOMER PROTECTIONS THE COMPANY IS PROPOSING DURING THE MYP TERM.

A. The Company is proposing an Earnings Test and the continuation of the current gas QSP through 2020. The current electric MYP includes this same package of protections, which we believe have worked well for customers. However, in this proceeding the Company is proposing some modifications to the earnings sharing bands and an adjustment to the material changes to expense thresholds.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EARNINGS TEST.

A. Similar to the electric MYP filing requirements, the Company would submit a report each year by April 30 detailing its returns for the previous calendar year.

These returns would be derived consistent with historically approved regulatory principles. Mr. Berman lists these principles in his Direct Testimony.

For each performance year (2018, 2019 and 2020) the Company would absorb all under-earnings below the authorized return of 10.0 percent. Shareholders and customers would share equally any earned returns from 10.01 percent to 12.0 percent. Any return above 12.0 percent would be returned to customers. These sharing bands are depicted in Table SBB-D-5 below;

Table SBB-D-5

Earned ROE	Customer Share	Shareholder Share
10.00%	0%	100%
10.01% - 12.0%	50%	50%
> 12.0%	100%	0%

Q. WHY IS THE COMPANY PROPOSING THESE SHARING BANDS?

A. The proposed structure of the bands is similar to the sharing band structure for the current electric MYP in the following respects:

- There are three tiers.
- The mechanism is asymmetrical. The Company would absorb all under-earnings and return partially or completely any over-earnings.
- Customers and shareholders would share equally any returns in the second tier.
- Any returns in the third tier would be returned 100 percent to customers.

But there is one difference: The Company proposes to extend the second tier from 65 basis points in the electric MYP to 200 basis points in the gas MYP.

Q. WHY IS THE COMPANY PROPOSING A WIDER SECOND TIER?

A. As mentioned earlier, one of the most important advantages of an MYP is that it encourages utilities to operate efficiently. Under the current electric MYP, the Company has a pronounced incentive to reduce costs if it is in an under-earnings position. But we have a muted incentive to achieve savings if it we are in an over-earnings position. The reason is that any returns above 10.48 percent are returned 100 percent to customers. The electric earnings sharing mechanism was a conservative mechanism that may have made sense for an early MYP. But as a long-term policy, the Company believes that MYPs should include more upside earnings potential and greater efficiency incentives. The Company's proposed earnings sharing mechanism in this proceeding would allow for a modest increase in our upside earnings potential. After the application of the earnings sharing mechanism, we could earn up to 100 basis points above our authorized return on equity.

Q. HOW WOULD THE EARNINGS SHARING BANDS CHANGE IF THE COMMISSION APPROVED A DIFFERENT AUTHORIZED ROE?

A. The Company would propose the same structure outlined above, but ratchet the thresholds up or down to reflect the Commission's authorized ROE. Shareholders would absorb all under-earnings. Shareholders and customers would share equally any returns up to 200 basis points above the authorized ROE. Any returns of more than 200 basis points above the authorized return would be returned 100 percent to customers.

This same approach would also be used to adjust the thresholds in 2019 and 2020 if the Commission approved the Company's recommendation to adjust the authorized ROE in these two years for significant changes to an index of bond yields. (See the Direct Testimony of Company witness John Reed.)

Q. IS THE COMPANY PROPOSING ANY CUSTOMER PROTECTIONS REGARDING SERVICE QUALITY?

A. Yes. The Company proposes to extend the current QSP for the gas department through the term of the proposed MYP – or through 2020. This QSP includes standards for manual meter reading errors and time to complete permanent repairs on recorded leaks. Total meter reading errors must remain below 0.007484 percent of the manually read meters. Also, system average time to permanently repair a reported leak must remain under 9.77 days. The Company is subject to financial penalties up to $1 million total if these metrics are not met.

As Mr. Litteken explains in his Direct Testimony, the Company also proposes metrics that it must meet in return for approval of an Enhanced Emergency Response Program. Specifically, the Company must respond to a certain percentage of emergency calls within 60 minutes or less.

E. Adjustments for Material Changes to Expenses

Q. IS THE COMPANY PROPOSING ANY ADJUSTMENTS FOR MATERIAL CHANGES TO EXPENSES FOR THE MYP?

A. Yes. We are proposing the same adjustments for material changes to expenses as included in the current electric MYP with one exception explained below.[2] These proposed adjustments for material changes to expenses protect customers and shareholders against significant changes to costs during the MYP period resulting from changes to: Generally Accepted Accounting Principles ("GAAP"), tax laws (other than property-tax laws), or federal, state or municipal laws or regulations. These adjustments for material changes to expenses are set out in my Attachment SBB-2.

Q. WHAT MODIFICATION DO YOU PROPOSE TO THE PROVISIONS IN THE ELECTRIC MYP?

A. For the gas department, the Company proposes to lower the threshold for the minimum annual impact of any single change to $5 million. (The threshold under the current electric MYP is a minimum annual impact of $10 million.) We propose this modification to recognize that the gas department operates on a smaller scale than the electric department, such that a dollar change in expense for the gas department has a larger impact on customer bills and the Company's ROE than the same dollar change in expense for the electric department. For

[2] I am using the term "adjustments for material changes to expenses" to refer to adjustments to rates during the MYP period that do not result in the termination of the plan. Dr. Lowry uses the term "Z Factor" when referring to such adjustments in his Direct Testimony.

example, our total gas revenues are about one-third of our total electric revenues, even though we serve approximately the same number of customers.

F. Elimination of PSIA

Q. WHY IS THE COMPANY NOT REQUESTING AN EXTENSION OF THE PSIA PAST ITS CURRENT EXPIRATION DATE OF DECEMBER 31, 2018, AS PART OF IT MYP PROPOSAL?

A. The Company initially requested the PSIA in a 2010 general rate proceeding because our integrity costs met the typical criteria for a rider or adjustment clause: they were large in magnitude, volatile, and difficult to predict, and largely outside of the utility's control.

The expenses are still large, growing and subject to fluctuation. But the Company has gained experience with these programs and can predict the costs better than it could when the PSIA was first implemented. If growing costs can be predicted with a reasonable degree of accuracy, then a MYP can substitute for a rider in terms of allowing a fair opportunity for cost recovery. In other words, the increasing levels of integrity costs can be recovered through a series of base rate adjustments instead of a rider. Notably, that approach would not work under the scenario of rates based on a single test year – regardless of whether that test year was an HTY or FTY. Under that scenario there would be a need for annual rate cases to capture the increases in integrity costs.

The support the Company has received from the Commission and Commission Staff over the past decade for our essential integrity work and the

PSIA has been critical and very much appreciated. But the end goal has always been to incorporate our integrity programs into the ordinary course of business and eliminate the rider. The proposed MYP provides the vehicle to accomplish this objective.

Q. DOES THE ELIMINATION OF THE PSIA ELIMINATE ANY CONCERNS THAT THE COMMISSION PREVIOUSLY EXPRESSED ABOUT MYPs?

A. Yes. In his Recommended Decision in Proceeding No. 15AL-0135G ("2015 Phase I rate case") the Administrative Law Judge ("ALJ") cited the availability of cost recovery through the PSIA as a primary reason for concluding that a MYP was not warranted (Decision No. R15-1204, paragraphs 92 and 94). The ALJ's findings are reproduced in part below:

> Had Public Service approached this gas rate case without the PSIA rider currently in place, or should the rider have expired, there may have been adequate support for the adoption of the proposed MYP. Here however, as discussed in more detail below, the PSIA will be extended an additional three years. Consequently, Public Service should not suffer the earnings attrition or a lag in revenue it anticipates as the projects it proposes are undertaken. Nor is there evidence that the use of an HTY renders the Company's gas system unsafe or unreliable.
>
> Public Service provides no compelling or persuasive evidence that its business practices have changed significantly

> since its last gas rate case, or that it is suffering from any adverse situations outside of its control such as high inflation, high interest rates, or rapid expansion in utility facilities. Public Service provides little information to support a finding that implementation of its proposed MYP would serve the public interest and benefit ratepayers. Most importantly, however, is the evidence provided by the Office of Consumer Counsel ("OCC") and Staff that the Company has a recovery mechanism in the PSIA for capital costs and expenses related to its current infrastructure spending which protects Public Service from the harm it claims the MYP would protect against.

As evidenced by the Company's recent under-earnings that I will discuss later in my Direct Testimony, the Company disagrees with the finding that the PSIA obviated the need for an MYP. Nonetheless, because the Company is not requesting an extension of the PSIA beyond its current expiration date, we have eliminated this concern about approving an MYP.

G. <u>Long-Term Planning</u>

Q. HAS THE COMPANY PROVIDED TESTIMONY EXPLAINING LONG-TERM PLANNING AND INITIATIVES?

A. Yes. The testimony of the 17 witnesses in this proceeding provides a very good perspective on our long-term planning. Some examples are provided below:

- Ms. Campbell and Mr. Litteken discuss a variety of initiatives to improve integrity and ensure adequate delivery capacity through 2020. These initiatives include the Enhanced Emergency Response Program; the Damage Prevention Program; the on-going effort to replace inside meters, carried over from the 2015 Phase I proceeding; the Downtown Denver Reinforcement (now called the North Metro Reinforcement), which adds an additional source of gas to the Denver Metro area; and the Tungsten to Blackhawk pipeline, which adds capacity to the suburban and foothills communities.
- Ms. Campbell discusses how we ensure adequate system capacity to meet customers' peak needs over the long term.
- Ms. Campbell discusses initiatives beyond the MYP term, such as the upgrades to the Mountain System and meter exchanges.
- Mr. Brossart discusses how the Work Asset Management and General Ledger investments will benefit customers over the long term.
- Mr. Robinson discusses our capital budgeting processes and planned expenditures for Property Services.
- Ms. Schell and Mr. Reed discuss the Company's five-year forecasts of capital expenditures and potential future changes to capital markets.
- I discuss the Company's hope to rely on MYPs in the future instead of frequent rate cases.

The Company is using our MYP filing to socialize our long-term plans with the Commission and stakeholders. Phase I rate filings that are based on a single test year do not facilitate this discussion.

H. Commitment to File a Phase II Rate Case

Q. IS THE COMPANY PROPOSING TO READJUST ITS CUSTOMER RATES DURING THE MYP TERM?

A. Yes.

Q. WHY?

A. One common ratemaking practice in Colorado is to separate into two different proceedings the revenue deficiency and rate-design portions of traditional rate cases. The first proceeding determines the total amount of money that utility rates should be designed to collect; or the size of the pie. The second determines how much of this total revenue requirement should be collected from each class of customers and the specific rate design that should applied to each class, or how the pie should be sliced. These proceedings are referred to as “Phase I” and “Phase II” proceedings, respectively.

This practice reduces the scope of issues that must be addressed in any one proceeding, which in that respect eases the burden on the Commission and stakeholders. Nonetheless, in the past stakeholders have expressed concern about multiple Phase I proceedings being processed without any realignment of class cost responsibilities and rates through a Phase II proceeding. In this particular case, the transfer of costs from the PSIA to a base-rate adjustment will affect the relative share of costs borne by our various customer classes. This significant shift reinforces the need for a Phase II proceeding.

To address these concerns about the equitable allocation of costs and rate design, the Company commits to filing a Phase II rate case within three months of receiving a final Commission Decision in this proceeding. This filing would allow for a Commission Final Decision at or around the beginning of 2019. Moreover, the Company would propose base rates designed to collect the 2019 GRSA that the Commission approves in the instant proceeding. This approach would allow the reallocation of costs and new rate design to become effective at the same time or shortly after the date on which the PSIA is eliminated – which would significantly reduce or eliminate the recovery of integrity costs through a GRSA.

I. Impacts on Rates After the MYP Period

Q. WHAT IS THE RELEVANCE OF RATES SET FOR THE MYP PERIOD TO A FUTURE PERIOD?

A. In utility ratemaking one issue that often lurks under the surface is the deferral of cost recovery to future periods. The salient example is an explicit regulatory asset. A regulatory asset -- to the extent there is reasonable certainty of future cost recovery -- represents an obligation to recover previously incurred costs from future customers. While there are often good reasons for such deferrals, they do cut against the objective of charging customers in any given period for the costs of providing service during this same period. This result does not promote the ratemaking goal of ensuring “inter-generational equity” among vintages of customers.

Q. ARE REGULATORY ASSETS THE ONLY EXAMPLE OF DEFERRING COSTS TO FUTURE PERIODS?

A. No. Deferring depreciation rate increases is another, less explicit way of deferring costs to future customers. Recording expenses on a cash rather than an accrual basis could also lead to cost-shifting from one period to another.

Q. HAS THE COMPANY ATTEMPTED TO MITIGATE SUCH INTER-GENERATIONAL INEQUITIES IN THIS PROCEEDING?

A. Yes. The revenue requirements for the proposed MYP ensure that all deferred balances up to the start of the MYP period will be recovered during the MYP period. Also, The Company is limiting ongoing deferrals to only those expenses that are difficult to predict. When warranted we are calibrating the deferred amounts to projected levels of costs. This approach tends to reduce the balances that customers would be responsible for after 2020, as opposed to using historical levels of expenses. Finally, the Company is requesting updated depreciation rates for our most significant accounts. Such updates prevent the need for more significant updates in future proceedings. Frequent updates to depreciation rates help ensure that customers receiving service during one period do not subsidize customers receiving service during another period.

I think it is fair to conclude that we, are not “kicking the can down the road” regarding cost recovery or running up bills for service provided today that future customers must pay.

VI. USE OF FORECASTS TO SET RATES

A. Overview

Q. WHY DOES THE COMPANY BELIEVE THAT SETTING RATES BASED ON FORECASTS OR INDICES IS REASONABLE?

A. Before directly explaining the advantages of basing rates on projections, I would like to address two common misconceptions.

Q. WHAT IS THE FIRST MISCONCEPTION?

A. The first misconception is that the use of indexed or forecasted costs means that historical information is ignored. Nothing could be further from the truth. Projections based on indices or forecasts almost always rely on historical costs as a starting point.

For example, the Company applies its proposed O&M indices to historical 2016 O&M expenses to derive O&M expenses during the MYP period. This historical base is critical to the development of the MYP O&M expenses. Similarly, much less than 50 percent of the Company’s forecasted rate base during the MYP period is attributable to incremental capital additions from 2017 through 2020, even though the Company is expecting relatively high levels of capital expenditures during that period. Most of the rate base is attributable to plant already on the Company’s balance sheet.

Q. IS HISTORICAL INFORMATION ALSO USED TO FORECAST REVENUE?

A. Yes. As Company witness Jannell E. Marks explains in her Direct Testimony, the Company uses a robust series of historical data to forecast future sales and customer numbers. Historical data is not ignored.

Q. WHAT IS THE SECOND MISCONCEPTION?

A. The second misconception is that the use of HTYs eliminates the need for projections. I do not believe that forward-looking assessments can be avoided in any proceeding where a utility is requesting a general rate adjustment. Even if a HTY is used to set rates, there must be some recognition that the rates developed through the HTY will be just and reasonable in at least one subsequent year – and preferably longer. That assessment requires a judgment (or forecast) of future conditions – even if that forecast is implicit rather than clearly articulated. Moreover, explicit forecasts are almost always used to establish the authorized return on equity even when HTY are used.

Q. WHAT ARE THE ADVANTAGES OF USING FORECASTS OR INDICES TO DEVELOP TEST-YEAR COSTS AND REVENUES?

A. I believe the broad and explicit use of forecasts for test-year revenue requirements offers the following advantages over using historical information:

- Rates based on forecasts promote the public-policy goals of matching the incurrence of costs with their recovery from customers during the period rates are effective.

- Rates based on forecasts rather than historical information can provide the Company with a fairer opportunity to earn its authorized ROE. This benefit is particularly important given recent cost and revenue trends.
- Contrary to common criticisms, rates based on forecasts do not weaken the utility's incentive to reduce its costs and operate efficiently.
- Rates based on forecasts provide a reliable basis for setting rates.
- Forecasted costs and revenues can be reviewed much in the same way that historical information is reviewed.
- The use of a FTY is not unusual; many jurisdictions have successfully used FTYs to set utility rates.

I will address each of these advantages in turn.

B. Matching of Cost Recovery with Cost Incurrence

Q. WHY IS IT IMPORTANT FOR RATES TO MATCH COST RECOVERY WITH COST INCURRENCE?

A. There is disagreement over the types of test years that should be used in utility ratemaking and whether utility rate proceedings should develop rates for a single test year or for multiple years (such as in an MYP). Nonetheless, I believe there is consensus on at least one issue: an important goal of utility ratemaking is that the recovery of costs through rates during a specific should match the utility's prudently costs incurred during that same period.

The qualifier "prudently incurred" is important, because the utility should not be allowed to recover any imprudent costs that it actually incurred or forecasts to incur. Moreover, the exact matching of cost incurrence and cost recovery is extremely rare: A utility faces many business risks that can result in an under- or over-recovery of costs. Nonetheless, when setting rates it is generally desirable to set rates that *on an expected basis* will yield revenues equal to the prudently incurred cost of service – including a reasonable return on equity capital.

Q. WHY DOES USING FORECASTED COSTS AND REVENUES OR INDICESPROMOTE THIS GOAL?

A. If rates are based on costs and revenues from a historical period, then they may be far removed from the rates required to recover costs during the year(s) the rates are actually in effect. This distortion will occur regardless of the precision of the test-year costs and revenues. Even if they are verified with 100 percent accuracy, they do not capture the inevitable changes to either the Company's costs of providing service or customer billing determinants in later years.

The use of a forecasts (or indices) mitigates this problem, particularly when the new rates are implemented when the test year begins or soon thereafter. Admittedly, even excellent forecasts are never 100 percent accurate. But they can still yield rates that are more accurate during the period in which they are in effect than rates based on totally precise costs and revenues for the wrong period.

Q. DOES THE INCLUSION OF KNOWN AND MEASURABLE CHANGES RECTIFY THIS PROBLEM WITH HTYs?

A. No. Known and measurable changes are usually very limited. Obviously, the cost or revenue change must be known with a great deal of certainty to satisfy the literal meaning of the standard. Moreover, in Colorado capital adjustments have been generally prohibited, and adjustments to O&M expenses must occur within 12 months of the test year.

Ironically, HTYs adjusted for known and measurable changes are superior to unadjusted HTYs because the adjustments represent a step towards forecasted test years, i.e., an adjusted HTY is a forward test year on training wheels. If so, why not extend this approach to its logical conclusion? In other words, why not use market based indexing or the budgeting or forecasting approach that virtually all businesses and governmental agencies use for their planning?

C. <u>Opportunity to Earn Authorized Return</u>

Q. DO YOU BELIEVE A HISTORICAL TEST YEAR ALLOWS A UTILITY A REASONABLE OPPORTUNITY TO EARN ITS AUTHORIZED RETURN?

A. No. A historical test year will provide a utility a reasonable opportunity to earn its authorized return only by accident. Specifically, O&M expenses, rate base and billing determinants must change by about the same percentage from the test year until the date new rates are placed in effect. Moreover, other cost drivers such as tax rates and bonus depreciation provisions must not change materially. This alignment almost never occurs. If a utility experiences a material deficiency that triggers the need for rate relief, the trend that caused the need for relief may worsen or improve. If it worsens, the need for relief will be even greater. If it improves (e.g., sales growth beyond the historic year is stronger than anticipated), the utility will typically be able to reduce the deficiency. In either case, rates based on historical costs and revenues do not recognize such changes.

Rates based on forecasts or indices capture projected levels of costs and revenues during the period in which rates will be in effect. While not perfect, this approach offers the best chance of accurately measuring the true level of the deficiency -- regardless of economic conditions or other factors subject to change.

Conceptually, using indices or forecasted costs and revenues is simply an extension of the traditional regulatory approach to estimating a utility's required return on equity. We do not look backward to measure the market return required in a historical period. Rather, ROE experts in utility rate proceedings attempt to measure a utility's required ROE based on a forward-looking analyses.

Q. ARE THERE CIRCUMSTANCES THAT MAKE THE USE OF FORECASTS OR INTEGRITY EVEN MORE COMPELLING?

A. Yes. Several factors can render the need even more critical. Among these factors are increases in input costs (inflation), the need for significant levels of new investment (additions to rate base), and tepid or flat sales growth. As I explained above, over the past few years the billing determinants that drive our revenues have increased at a much lower rate than our key cost drivers – such as rate base, property taxes and O&M expenses.

Q. DO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES INDICATE THAT THIS TREND WILL CONTINUE?

A. Yes. The Company's capital budget reflects relatively high levels of spending. Public Service expects its annual capital expenditures for the gas department (including an allocation of common plant) to average $420 million from 2017 to 2020. In comparison, our annual depreciation expense over the same period is expected to average only $118 million. When expenditures far exceed depreciation expense, rate base and capital costs will increase significantly.

The Company believes our planned investments over the next few years are essential to our continued provision of efficient, reliable, high-quality service. Nonetheless, they do increase our capital costs.

Q. WHAT IS THE SIGNIFICANCE OF THESE HIGHER LEVELS OF CAPITAL INVESTMENT?

A. Our ability to obtain the confidence of investors hinges on our ability to obtain a fair opportunity to recover prudently incurred investment and associated operating costs in a timely manner. As confidence in this recovery wanes, our credit metrics will deteriorate and our financing costs will tend to increase. Customers will ultimately bear higher financing cost through higher rates.

Q. CAN YOU PROVIDE A PRACTICAL EXAMPLE OF HOW THE USE OF A HISTORICAL TEST YEAR AFFECTS THE RECOVERY OF INVESTMENTS?

A. Yes. Assume an investment was placed in to service in July 2016. Assume a calendar-year HTY scenario with plant balances imputed at year-end levels. The earliest this investment would be captured would be in a 2016 HTY. The earliest the Company could file a Phase I rate case based on a calendar year 2016 HTY would be the second quarter of 2017. Rates resulting from this case would not be effective until around January 2018. In other words, even under the best-case scenario in terms of timing and the imputation of year-end plant balances, the costs of an investment placed in-service in July 2016 would not be recovered through rates until 1.5 years later. If the HTY were based on 13-month average rate base, then less than 50 percent of the investment would be recovered through rates even after an 18-month lag. The entire project costs would only be fully reflected in a 2017 HTY. Under that scenario the shortest lag between the in-service date of the project and its full recovery through rates would be 2.5 years.

Q. PLEASE SUMMARIZE YOUR DISCUSSION OF THE CONSEQUENCES OF A HISTORICAL TEST YEAR ON THE UTILITY'S ABILITY TO EARN ITS AUTHORIZED ROE?

A. Any regulatory model that fails to keep up with cost and revenue changes in a timely manner will ultimately pose problems for utilities seeking to raise the capital necessary to provide safe and reliable service. The financial markets may be reluctant to support the investment plans of a utility operating in such an environment, or they may support such plans only at a higher financing cost that customers will ultimately bear through higher rates. Given recent trends, I believe the Company's gas department – despite its superior performance -- finds itself in a situation where it cannot recover its prudently incurred costs in a timely manner without impairing service quality. Consequently, the need to change the ratemaking framework is even more important in today's environment than it has been in the past.

D. Impact of a Forecasted Test Year on Company's Incentive to Reduce Costs

Q. ANOTHER CONCERN OFTEN RAISED ABOUT USING FORECASTED COSTS AND REVENUES IS THAT THIS PRACTICE REDUCES THE UTILITY'S INCENTIVE TO OPERATE EFFICIENTLY. DO YOU AGREE?

A. No. This concern rests on two questionable assumptions. The first is that somehow the use of historical information rather than forecasted or indexed costs and revenues will provide the utility with a stronger efficiency incentive. But once rates are set, a utility realizes the same benefit from an given expense reduction between rate cases regardless of whether rates are set on the basis of historical or forecasted costs and revenues. For example, for every dollar of O&M expense reduction Public Service increases its earnings by about $0.62 after income taxes. Moreover, we have this same incentive to reduce expense regardless of whether we are currently under-earning or over-earning.

In fact, as Dr. Lowry explains, a key way to encourage efficiencies is to increase the lag between rate cases, MYPs actually provide a stronger efficiency incentive by allowing for a longer duration between rate cases than if HTYs are used.

The second assumption is that large companies can start and stop efficiency efforts based on the timing of rate cases. But efficiency gains typically are not realized overnight. Most efficiency improvements result from the identification of a potential savings opportunity; the development of a new process or new technology to capture the savings; and the deployment and implementation of the process or system followed by refinements and further improvements. There is simply no way that a utility can encourage its personnel to plan this activity to occur only outside of test years.

Utility shareholders may be the primary beneficiaries of efficiency gains in the short term, while customers ultimately benefit from these same efficiencies when they are captured in future rates. The fact that customers ultimately reap the benefits of efficiency initiatives does not lessen the Company's financial incentive to increase earnings until rates reflect the efficiency gains.

Further, I believe that capital markets add an additional and independent incentive for a utility to achieve efficiency gains. For example, investors are concerned about high levels of O&M growth. They know that high levels of spending are not likely to be viewed favorably in the rate-setting process.

Q. IS THERE ANY EMPIRICAL EVIDENCE THAT HTYS DO NOT IMPROVE A UTILITY'S EFFICIENCY?

A. Yes. The Company directed PEG to conduct a study of whether HTYs result in efficiency gains. Based on this study Dr. Lowry found no tendency for real costs to grow more slowly for utilities that use historical test years.

E. Reliability of Forecasted Costs

Q. YOU INDICATED PREVIOUSLY THAT A FORECASTED TEST YEAR WOULD BETTER MATCH COST INCURRENCE WITH COST RECOVERY. BUT WON'T RATES BASED ON FORECASTS BE LESS ACCURATE SIMPLY BECAUSE COSTS AND REVENUES CANNOT BE PREDICTED WITH 100 PERCENT ACCURACY?

A. I agree that projections by definition are subject to some uncertainty, i.e., they do not offer the same false sense of precision that HTYs do. Some reasons for this lack of precision are the following:

- A sales forecast is not likely to capture the impact on sales of unforeseen economic turndowns, extraordinary economic growth in a particular region, or material changes in customer behavior or introduction of new technologies.
- A capital budget may not capture project delays due to permitting or siting issues, while new projects may be added due to unanticipated equipment failures.
- Large capital additions may come in above or below budget.

But this uncertainty must be placed in perspective. The level of uncertainty introduced through the use of forecasts is almost always narrower than the level of uncertainty introduced by assuming that circumstances during a historical test year will be repeated during the period that rates are in effect. As a result, using historical information makes it more difficult to achieve a principle goal of ratemaking – that the costs and revenues used to set rates should be representative of the utility's prudently incurred costs and revenues when the rates are in effect. In reality, customer demand, input costs and statutory or regulatory requirements often change significantly during the (approximately) two-year gap between the historical test year and the implementation of rates based on that test year. The changes are even greater in subsequent years. As long as rigorous processes are employed for budgeting capital and O&M expenses and forecasting billing determinants, the costs and revenues used for a forecasted test year will almost certainly be closer to the actual costs and revenues incurred during the effective period of the new rates than historical costs and revenues.

This is what I mean when I observe that HTYs offer a false sense of precision: It is better to be approximately right than exactly wrong.

Of course, the extent to which an FTY is more accurate depends on the quality of the budgeting processes. As explained by other Company witnesses, the Commission should take some comfort in the rigor of the Company's budgeting processes. We have internal controls in place to ensure that the budgets and forecasts are accurate and customer needs are satisfied at a reasonable cost of service. Regulatory bodies in other jurisdictions in which Xcel Energy operates have used our budgets to set rates for many years.

Q. CAN THE INACCURACIES INHERENT IN EVEN SOUND BUDGETING PROCESSES BE REDUCED THROUGH UPDATES?

A. Yes. During the course of rate case proceedings, the Company usually updates its projected costs and revenues such that the regulatory body can have the best information.

Q. EVEN WITH THE SAFEGUARDS MENTIONED ABOVE, DOES THE UTILITY HAVE AN INCENTIVE TO OVERSTATE COSTS AND UNDERSTATE REVENUES?

A. I do not believe this concern is significant as long as the utility uses the same data and processes for projecting sales and costs in test years as it does when it is not in a test year. In other words, the utility must have a strong and consistently managed budgeting process. As other witnesses support in more depth, Xcel Energy has established such processes for the parent and each of its four utility subsidiaries, including Public Service. Our request reflects the outcome of the same process that is ultimately used to provide financial guidance to the investment community. This guidance includes key assumptions -- such as the expected level of sales growth and our investment plans.

Q. IS THE COMPANY REFLECTING IN ITS PROPOSED TEST-YEAR COST OF SERVICE ANY ADJUSTMENTS TO ITS BUDGETED CAPITAL PRESENTED IN THIS CASE?

A. Yes. Prior to submitting this filing, we reviewed our budgets to determine the need for any refinements to our expected capital expenditures in 2018 through 2020. Based on this review we reflected the following changes:

- Adjustments were made to remove a common general project related to the Advanced Grid Initiative and Security ("AGIS") project as discussed by Company witness David C. Harkness;
- An adjustment was made to reclassify the Critical Infrastructure Protection ("CIP") Substation Phase 2 project out of common intangible and move it to Electric Intangibles; and
- An adjustment was made to reflect a change to the in-service date associated with an upgrade to the Customer Resource System ("CRS").

In aggregate, these adjustments have little impact on the test-year cost of service or revenue deficiency; the 2018 through 2020 forecasts of capital expenditures are still the cornerstones of our projected test-year plant additions.

Q. IS THE COMPANY WILING TO PROVIDE APPROPRIATE UPDATES AS MORE ACTUAL AMOUNTS BECOME AVAILABLE?

A. Yes. The Company is committed to providing such updates, as warranted, during the course of this proceeding. However, we are not expecting significant changes.

Q. YOU HAVE EXPLAINED HOW CAPITAL EXPENDITURES FOR THE MYP PERIOD ARE PROJECTED AND UPDATED. WHEN WAS THE DEMAND FORECAST USED FOR PURPOSES OF DETERMINING MYP REVENUE DEVELOPED?

A. As explained by Company witness Jannell E. Marks, the Company is using its 2017 financial customer and throughput forecast developed in March 2017 to project MYP billing determinants. This forecast is based on actual customer numbers and throughput volumes through December 2016. Consequently, the Company is not relying on dated forecasts.

As with capital expenditures, the Company will update these forecasts of customer numbers and throughput as warranted during this proceeding.

Q. IN CONCLUDING THIS SECTION, IS THERE ANY PARTICULAR TESTIMONY FROM OTHER COMPANY WITNESSES THAT YOU WISH TO HIGHLIGHT?

A. Yes. Mr. Robinson thoroughly explains the Company's budgeting and forecasting process on Pages 13 - 39 of his Direct Testimony and why it is appropriate to use in regulatory proceedings. I wish to cite two particular passages from his Direct Testimony to buttress my discussion above. The first is found on Page 33, Line 17, through Page 34, Line 5, of his Direct Testimony:

> It is important to remember that no business can ensure that every budgeted dollar is spent in exactly the same way that it was initially forecasted to be spent. Nor would this be a reasonable expectation, as it would preclude a company from being flexible or responding to emergencies, unexpected changes in the business, in customer needs, or in the marketplace as a whole. What is important is that overall the

> Company's budgets reflect a reasonable level of costs and are reasonably representative of the costs the Company will incur to deliver gas utility services to its customers during each year of the budget periods.

I believe this a very salient point; while line-by-line reviews have their place, they can often result in missing the forest for the trees.

The second citation is found on Page 16, Line 21, through Page 17, Line 4, of Mr. Robinson's Direct Testimony:

> The use of a robust budgeting process provides regulatory support for the use of a future test year or years that rely on those budgets. Further, Public Service believes – and Xcel Energy operating companies in other jurisdictions have found – that a forward-looking test year more accurately and transparently represents the work that the Company will do during the period rates are in effect.

This passage is also important to bear in mind. The information the Company is asking this commission to accept for ratemaking purposes has been accepted in other jurisdictions and for other important financial purposes.

F. Regulatory Review of Forecasts or Indices

Q. ARE MYPS BASED ON FORECASTS OR INDICES SIGNIFICANTLY MORE DIFFICULT TO REVIEW THAN HTYs?

A. As with any rate case, the Commission should expect its Staff and other intervenors to probe the reasonableness of the Company's request. However, this undertaking should not significantly change if the test years are based on forecasts or indices instead of historical data.

For example, an investigation of the reasonableness of a historical test year for purposes of setting rates typically includes a review of:

- whether any costs were non-recurring;
- whether any costs were at atypical levels that need to be normalized;
- whether sales were materially affected by weather and should be normalized; and
- whether investments in plant were reasonably needed to provide adequate utility service and, particularly for larger projects, if they were prudently managed such that the costs in rate base are reasonable.

A similar review of our Public Service costs in the case is required for the Commission to assure itself that the costs and revenues provide an accurate basis for setting rates. This review involves an evaluation of historical trends, budget accuracy, the appropriateness of proposed indices, whether any material changes in costs are justified as ongoing changes, and whether material changes in circumstances since the time the budget was created were appropriately reflected in the test year. If there are questions or concerns not satisfactorily answered by the Company, adjustments are typically made. While there may be disagreements about the reasonableness of certain cost levels, I do not believe those disagreements should be viewed any differently in the context of an MYP based on a forward test year than an HTY.

Moreover, to the extent costs and revenues are based on indices the review may actually be more streamlined. For example, the use of indices reduces or eliminates the need to review budgets. Instead, indices compiled by recognized experts can help ensure the reasonableness of the utility's proposed price increases.

Q. BUT DOESN'T A THOROUGH REGULATORY REVIEW OF MYPS BASED ON MULTIPLE TEST YEARS REQUIRE MORE RESOURCES AND TIME?

A. Reviewing multiple test years is more time-consuming than reviewing one test year – but it is not as if the review of three test years takes three times as long as the review of one test year. Rate cases impose common time and resource commitments that do not vary much with the number of years examined. The review of the first year will answer questions regarding the second and third years as well.

Moreover, there is also the other impact of MYPs on regulatory resource requirements. Since utilities operating under MYPs will file rate cases less frequently, the regulatory costs over time will be less.

G. Precedent for Using Forecasted Test Years

Q. WHAT IS THE EXPERIENCE OF OTHER JURISDICTIONS IN ALLOWING FOR THE USE OF FORWARD OR FORECASTED TEST YEARS FOR SETTING UTILITY RATES?

A. Approximately 15 jurisdictions routinely use forecasted test years for ratemaking purposes, while another 9 jurisdictions occasionally use forecasted test years for ratemaking purposes and 8 other states employ "hybrid" test years that use a combination of historical and forecasted data. In addition, Dr. Lowry provides a map indicating the states that have allowed MYPs. Of course, Colorado is one such state. These states include both those that primarily use forecasted test years and those that use historical test years. If the Commission determines that our proposed MYP provides a reasonable basis for setting rates, we are committed to using this approach moving forward absent unusual circumstances.

VII. REASONABLENESS OF COMPANY'S PROPOSED RATES AND BILL IMPACTS

A. Reasonableness of Rates

Q. ARE THE RATES THE COMPANY PROPOSES IN THIS PROCEEDING REASONABLE, AND DO THEY DEMONSTRATE THAT THE UTILITY IS OPERATING EFFICENTLY AND OFFERING A GOOD PRICE PROPOSITION TO CUSTOMERS?

A. Yes. Intervenors will no doubt conduct a thorough review of our test-year expenses and revenues over the MYP period. This line-by-line examination is still the primary way to ensure just reasonable rates for regulated gas utilities in Colorado and other states as well. But the Company believes that it is also very useful – and arguably more useful from the perspective of customers – to assess the reasonableness of a utility's bottom-line prices based on benchmarking studies, national rankings, and historical bill changes. The metrics can offer good insights into whether a utility is truly offering good value to customers. I believe that the Company's rates are very reasonable based on all three of these metrics.

Q. ARE THE COMPANY'S RATES LOW BY NATIONAL STANDARDS?

A. Yes. The American Gas Association compiles an annual ranking of the average prices charged by gas distribution utilities. The most recent year for which data is available is 2014, during which the Company's residential gas rates were the 10th lowest of the 111 utilities included in the study. Attachment SBB-3 provides more detail on residential gas rates across the country. That ranking is a good barometer of the value we offer customers.

Q. COULD THIS SUPERIOR NATIONAL RANKING BE ATTRIBUTABLE TO SOME NATURAL ADVANTAGES THAT PUBLIC SERVICE ENJOYS DUE TO SIZE OR GEOGRAPHICAL LOCATION?

A. Those factors and other business conditions certainly affect a utility's cost structure and process. For this reason, the Company engaged PEG to conduct the econometric benchmarking study I referenced earlier. This study essentially develops predicted costs for utilities based on their specific business conditions. This analysis represents a significant improvement over simple benchmarks historically used -- such as O&M expense per customer -- that do not account for other important drivers of costs.

As Dr. Lowry explains in his Direct Testimony, both the Company's non-gas O&M expenses and non-gas total costs for the 2018 2019 and 2020 test years are well below their predicted values. In fact, out on the 33 utilities included in the econometric study, Public Service Company ranks 5th best in terms of non-fuel O&M expense and 7th best in terms of the non-fuel total cost of service. Both rankings represent first quartile performance. On average, the non-gas O&M expenses that the Company proposes are 33 percent below the benchmark generated by PEG's O&M cost model. Similarly, on average the total non-gas total revenue requirements that the Company proposes are about 23 percent below the benchmark generated by PEG's total cost model.

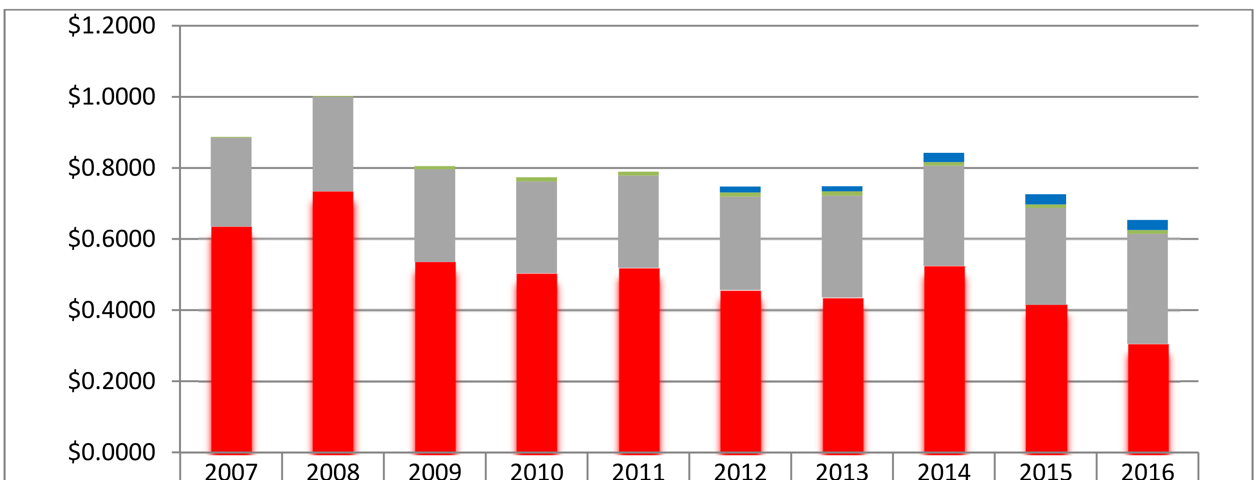
PEG also benchmarks the Company's costs using unit cost indexing. As Dr. Lowry notes, this study yields similar results regarding our cost efficiency. The proposed non-gas O&M expense is about 42 percent below the peer group mean. The proposed non-fuel total cost is about 18 percent below the peer group mean.

Q. HAVE CUSTOMERS EXPERIENCED SIGNIFICANT BILL INCREASES OVER THE PAST FEW YEARS?

A. No. As illustrated in Figure SBB-D-2 and Figure SBB-D-3 below, the Company's all-in rates to residential customers and small commercial sales customers have declined significantly over the past 10 years.

Figure SBB-D-2

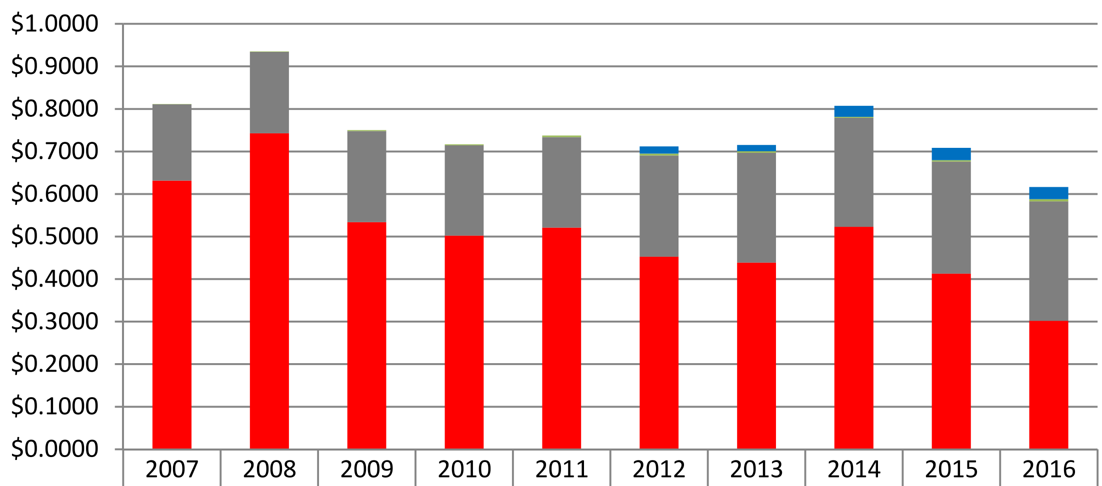
10 Year History of Residential Gas Rates



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PSIA						$0.0169	$0.0142	$0.0261	$0.0289	$0.0284
DSM	$0.0020	$0.0020	$0.0090	$0.0118	$0.0111	$0.0118	$0.0125	$0.0096	$0.0094	$0.0107
Base Rate	$0.2498	$0.2661	$0.2605	$0.2582	$0.2591	$0.2621	$0.2863	$0.2822	$0.2730	$0.3094
GCA	$0.6359	$0.7348	$0.5360	$0.5043	$0.5198	$0.4574	$0.4359	$0.5250	$0.4153	$0.3058
Total	$0.8877	$1.0028	$0.8056	$0.7743	$0.7901	$0.7483	$0.7489	$0.8429	$0.7266	$0.6542

Figure SBB-D-3

10 Year History of Small Commercial Gas Rates



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PSIA						$0.0169	$0.0144	$0.0261	$0.0289	$0.0284
DSM	$0.0009	$0.0009	$0.0023	$0.0022	$0.0037	$0.0047	$0.0038	$0.0021	$0.0033	$0.0054
Base Rate	$0.1790	$0.1914	$0.2142	$0.2123	$0.2127	$0.2378	$0.2584	$0.2561	$0.2636	$0.2807
GCA	$0.6317	$0.7427	$0.5339	$0.5024	$0.5212	$0.4527	$0.4386	$0.5231	$0.4127	$0.3018
Total	$0.8116	$0.9350	$0.7503	$0.7169	$0.7376	$0.7121	$0.7152	$0.8074	$0.7085	$0.6164

The average residential all-in rate declined by about 36 percent, while the average small commercial rate declined by about 32 percent. In contrast, the Consumer Price Index for Denver-Boulder-Greeley increased by 22 percent over the same period.

There is no doubt that lower commodity prices drove the lower prices. Regardless, the end result was that customers received stable or declining rates during the same period that Public Service was aggressively pursuing integrity initiatives to help maintain the safety and reliability of the system. For example, during this this same period the Company entirely removed cast iron mains and about 19,000 Cellulose Acetate Butyrate ("CAB") services from our system -- two of the higher-risk assets earmarked for replacement. Ms. Campbell explains how the Company is beginning to see improvements in safety and reliability metrics as a result of our integrity initiatives. I also note that average customer rates in 2016 were below rates in 2011 – the year before the PSIA was implemented.

Q. DID THE CHANGES TO THE TYPICAL RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER BILLS RELECT THIS SAME TREND?

A. Yes. In fact, since use per customer has generally decreased over this 10-year period, customers have benefitted from both lower prices and lower use. While most of the usage declined occurred due to market changes outside of the Company's gas DSM programs, our DSM programs did contribute to the reduction. For example, our 2016 gas DSM programs alone reduced annual residential customer use by about 412,000 dekatherms, which is almost 0.5 percent of our total residential sales.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS OF THE REASONABLENESS OF THE COMPANY'S RATES AND BILLS?

A. Our national price rankings and the PEG benchmarking studies demonstrate that the Company offers very affordable service to our customers and operates efficiently. Customers have enjoyed stable rates and bills over the past decade, during which time Public Service has invested heavily in our distribution system. In short, the data support the conclusion that we offer customers a very good price proposition.

B. Bill Impacts

Q. HAVE YOU ESTIMATED THE IMPACT ON TYPICAL CUSTOMER BILLS IF THE COMMISSION APPROVES THE COMPANY'S PROPOSED TARIFF CHANGES?

A. Yes, I am providing two sets of estimated bill impacts for 2018, 2019, and 2020. The first set captures incremental impacts of the Company's proposed changes in this proceeding, which include both our proposed GRSAs and the elimination of the PSIA in 2019.

The second set of bill impacts incorporates all forecasted changes to rates. This second set provides the Commission and stakeholders a more complete picture of how typical bills are expected to change over the next three years based on both the rate changes the Company proposes in this proceeding and other forecasted changes.

I present both dollar and percentage bill impacts for typical customers served under each of the Company's seven major rate schedules: RG, CSG, CLG, IG, TFS, TFL, and TI.

Q. WHAT ARE THE ESTIMATED INCREMENTAL BILL IMPACTS OF THE COMPANY'S PROPOSALS IN THIS PROCEEDING – YOUR FIRST SET OF BILL IMPACTS?

A. Table SBB-D-6 summarizes these impacts in 2018, 2019, and 2020.

Table SBB-D-6
Bill Impacts of the Company's Filing

	2018		2019		2020	
	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential (RG)	$ 2.73	6.08%	$ 2.19	4.58%	$ 1.74	3.49%
Small Commercial (CSG)	$ 10.91	5.67%	$ 6.97	3.43%	$ 6.95	3.31%
Large Commercial (CLG)	$ 84.65	2.61%	$ (181.23)	(5.44%)	$ 53.95	1.71%
Interruptible Sales (IG)	$ 90.63	1.35%	$ (649.17)	(9.56%)	$ 57.76	0.94%
Small Firm Transpotrt (TFS)	$ 47.30	10.58%	$ (9.76)	(1.97%)	$ 30.14	6.22%
Large Firm Transport (TFL)	$ 166.84	9.86%	$ (140.54)	(7.56%)	$ 106.33	6.19%
Interruptible Transport (TI)	$ 379.42	5.76%	$ (2,834.28)	(40.65%)	$ 241.82	5.84%

Q. WHAT ARE THE ESTIMATED BILL IMPACTS INCLUDING THE PROJECTED CHANGES TO ALL OF THE COMPANY'S RATES?

A. Table SBB-D-7 summarizes the estimated "all-in" dollar and percentage bill impacts of the collective changes to the GRSA, PSIA, and GCA. (For purposes of deriving these impacts I held the DSMCA constant at its current level.)

Table SBB-D-7
All-In Bill Impacts

	2018		2019		2020	
	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential (RG)	$ 4.11	9.36%	$ 0.72	1.49%	$ 1.64	3.37%
Small Commercial (CSG)	$ 17.18	9.15%	$ 0.28	0.13%	$ 6.52	3.18%
Large Commercial (CLG)	$ 423.65	13.51%	$ (369.10)	(10.37%)	$ (107.42)	(3.37%)
Interruptible Sales (IG)	$ 450.77	7.00%	$ (1,033.74)	(15.01%)	$ 33.21	0.57%
Small Firm Transpotrt (TFS)	$ 80.11	19.34%	$ (9.76)	(1.97%)	$ 30.14	6.22%
Large Firm Transport (TFL)	$ 316.62	20.52%	$ (140.54)	(7.56%)	$ 106.33	6.19%
Interruptible Transport (TI)	$ 1,526.92	28.04%	$ (2,834.28)	(40.65%)	$ 241.82	5.84%

Attachment SBB-4 provides additional detail on the estimated bill impacts resulting from the Company's proposals in this proceeding. Attachment SBB-5 provides additional detail on the estimated all-in bill impacts.

Q. ARE THE BILL IMPACTS DIFFERENT FOR DIFFERENT CUSTOMER CLASSES?

A. Yes. The proportion of a customer's bill attributable to base rates -- including the Service and Facility ("S&F"), Capacity, and Usage Charges – depends on the schedule under which the customer receives service. For example, base rates represent 37 percent of a typical Residential customer's total bill but 60 percent of a typical Large Firm Transportation customer's total bill Moreover, the bill impact of transferring recovery of integrity costs from the PSIA to base rates will vary among service schedules. Therefore, the Company's proposed GRSAs and PSIA roll-in will result in different percentage bill impacts on different types of customers. In turn, the dollar impacts on typical customers will reflect these same varying percentage impacts.

Q. DO THE BILL IMPACTS BASED ON THE PROPOSED CHANGES TO THE SCHEDULE OF CHARGES?

A. No. Charges listed in the Schedule of Charges are assessed to the individual customer who receives the service. These individual charges are not socialized across all customers or customer classes, so there is no collective bill impact for such changes. I will discuss the Company's proposed changes to the Schedule of Charges later in my Direct Testimony.

C. Service Quality

Q. YOU HAVE DOCUMENTED THE COMPANY'S LOW COST OF SERVICE. HAS THE COMPANY ACHIEVED LOW COSTS AND RATES BY JEOPARDIZING THE RELIABILITY AND SAFETY OF ITS SERVICE?

A. No. Of course, safety and reliability on the gas system are closely linked, as the same damage to or deterioration of mains and services that poses safety risks also leads to service disruptions. Consequently, the Company's integrity efforts address both safety and reliability. These efforts include not only our initiatives covered in the PSIA – such as data acquisition, pipeline assessments and pipeline replacement programs -- but other programs as well.

A salient example is our robust program designed to mitigate third-party damage to our system. Mr. Litteken explains that program in his Direct Testimony. In this respect I believe the Company has demonstrated a strong commitment addressing system integrity. These efforts are paying off. In 2014 the Company recorded 0.037 leaks per mile of main. That metric was reduced to 0.030 leaks per mile of main in 2016, which represents a reduction of approximately 20 percent. This improvement suggests that Public Service has identified and properly prioritized the correct mains to renew through our pipe replacement programs. In addition, the Company has removed 43 miles of bare steel and 75 miles of polyvinyl chloride pipe ("PVC") since the beginning of the Company's systematic pipe renewal programs. The Company has also stepped up our health assessments of transmission pipelines. Ms. Campbell discusses all of these projects in further detail.

Nonetheless, we have identified at least one crucial area where we need to perform better. Our average responses time to emergency calls has been too long. As Mr. Litteken explains, the Commission allowed us to increase our staffing in the last Phase I rate case subject to our meeting a performance metric. We have improved significantly, but not enough. Consequently, we are requesting additional staffing in this proceeding to further lower our response time.

Finally, as explained earlier, the Company is proposing the continuation of our gas QSP and performance metrics for our Enhanced Emergency Response Program.

As a whole, customers have received high-quality service. I do not believe our low cost of service gas been achieved or will be achieved at the expense of service quality.

VIII. SUMMARY OF 2016 HTY

Q. IS THE COMPANY PROVIDING AN HTY IN THIS PROCEEDING?

A. Yes. In compliance with a prior Commission directive, the Company is providing a 2016 HTY. This test year incorporates 2016 costs and revenues adjusted for known and measurable changes and is based on year-end plant balances. The Company uses year-end plant balances to mitigate attrition. But this adjustment by no means eliminates the problems caused by the use of stale historical data. Mr. Berman details the derivation of this test year in his Direct Testimony. The revenue deficiency for this test year is $67.6 million.

In this HTY the Company is proposing to amortize the net balance of regulatory assets as of January 1, 2018, over 18 months. This relatively short amortization period reflects our goal of amortizing all (or at least most) of the net regulatory balance before rates resulting from the next Phase I proceeding are implemented. As explained bellow, we plan to file another Phase I rate case in 2018 if an HTY is approved in this proceeding. That leaves a very short period for amortizing the regulatory balance.

Q. WHY IS THE COMPANY PROPOSING TO USE YEAR-END 2016 PLANT BALANCES AS THE BASIS FOR THE HTY?

A. The Company believes that HTYs should be based on plant balances at the end of the test year to recognize the lag between the test year and the effective dates of the rates.

Q. HAS A DEMONSTRATION OF ATTRITION BEEN USED AS A STANDARD FOR DETERMINING WHETHER THE USE OF END OF YEAR PLANT BALANCES IS WARRANTED?

A. Yes. In the Company's most recent Phase I rate proceeding (Proceeding No. 15AL-0135G), the ALJ rejected the Company's proposal to use year-end rate base. In Paragraph 171 of Decision No. R15-1204, he found that Public Service did not provide evidence demonstrating earnings attrition:

> Public Service provided no evidence to show that extraordinary conditions such as earnings attrition exist here for the Commission to adopt a year-end rate base calculation. It is therefore found that the rate base will be calculated using the 13-month average method except for the net investment in the Cherokee Pipeline, which should be calculated on a year-end basis.

Q. HAS THE COMPANY DEMONSTRATED EARNINGS ATTRITION IN THIS PROCEEDING?

A. Yes. As discussed previously, our earnings over the past few years clearly demonstrate earnings attrition. While the Company does not support using HTYs, using year-end rate base can help mitigate some of the problems with using historical data.

Q. IS THE COMPANY PROPOSING TO SIMILARLY ADJUST REVENUES?

A. Yes. The Company's HTY revenues are based on the year-end number of customers, which increases test-year revenues and decreases the revenue deficiency. Consequently, we believe we are applying the year-end adjustments consistently.

Q. IS THE COMPANY PROPOSING THAT THIS HTY BE USED TO DETERMINE THE COMPANY'S REVENUE DEFICIENCY IN THIS PROCEEDING?

A. No. The Company is proposing an MYP with revenue deficiencies based on our 2018, 2019 and 2020 test years. However, we do use the 2016 HTY as the base year for our O&M escalations explained above.

Q. IF THE COMMISSION WERE TO APPROVE AN HTY, WOULD THAT AFFECT OTHER REQUESTS AND FILINGS?

A. Yes. The Company would most likely:

- request an extension of the PSIA through 2020;
- request revenue decoupling for residential and small commercial customers; and
- file another rate case in 2018 and likely another case soon afterwards.

Q. WHY WOULD THE COMPANY SEEK SUCH AN EXTENSION TO THE PSIA?

A. Without a MYP that can account for projected annual increases to integrity costs, the Company would seek an extension of the PSIA to accommodate such increases. The problem would be particularly acute if HTYs were used to set base rates. We would be continually "chasing our tails" in term of recovering prudently incurred integrity costs.

Q. WHY WOULD THE COMPANY FILE ANNUAL OR FREQUENT PHASE I RATE CASES?

A. Even with a PSIA extension, the combination of higher non-integrity costs and weak revenue growth would perpetuate our under-earnings on an ongoing basis. Consequently, we would file another rate case in 2018 to address the projected deficiency in 2019. Depending on the outcome of that proceeding, we might need to file another rate case in 2019 to address deficiencies in 2020. Our recovery problems would be exacerbated if the rates approved in those proceedings were based on an HTY rather than a forecasted period.

In short, the Company's recourse absent an MYP would seem to be an increased reliance on both riders and more frequent rate cases. The need for frequent rate changes absent an MYP is borne out by our historical returns over the past few years.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE HTY?

A. Yes. While the Company is not proposing the use of an HTY in this proceeding, we are certainly not ignoring historical information. Legacy capital costs of assets installed before 2017 still constitute the bulk of our capital costs in each of the three MYP test periods, even though projected plant additions are significant during the MYP period. Likewise, our indexed and forecasted O&M expenses are grounded in the 2016 HTY O&M expenses.

IX. DRIVERS OF MYP REVENUE DEFICIENCIES

A. Overview

Q. WHAT ARE THE MAIN DRIVERS OF THE COMPANY'S REQUESTED RATE INCREASES OVER THE MYP PERIOD?

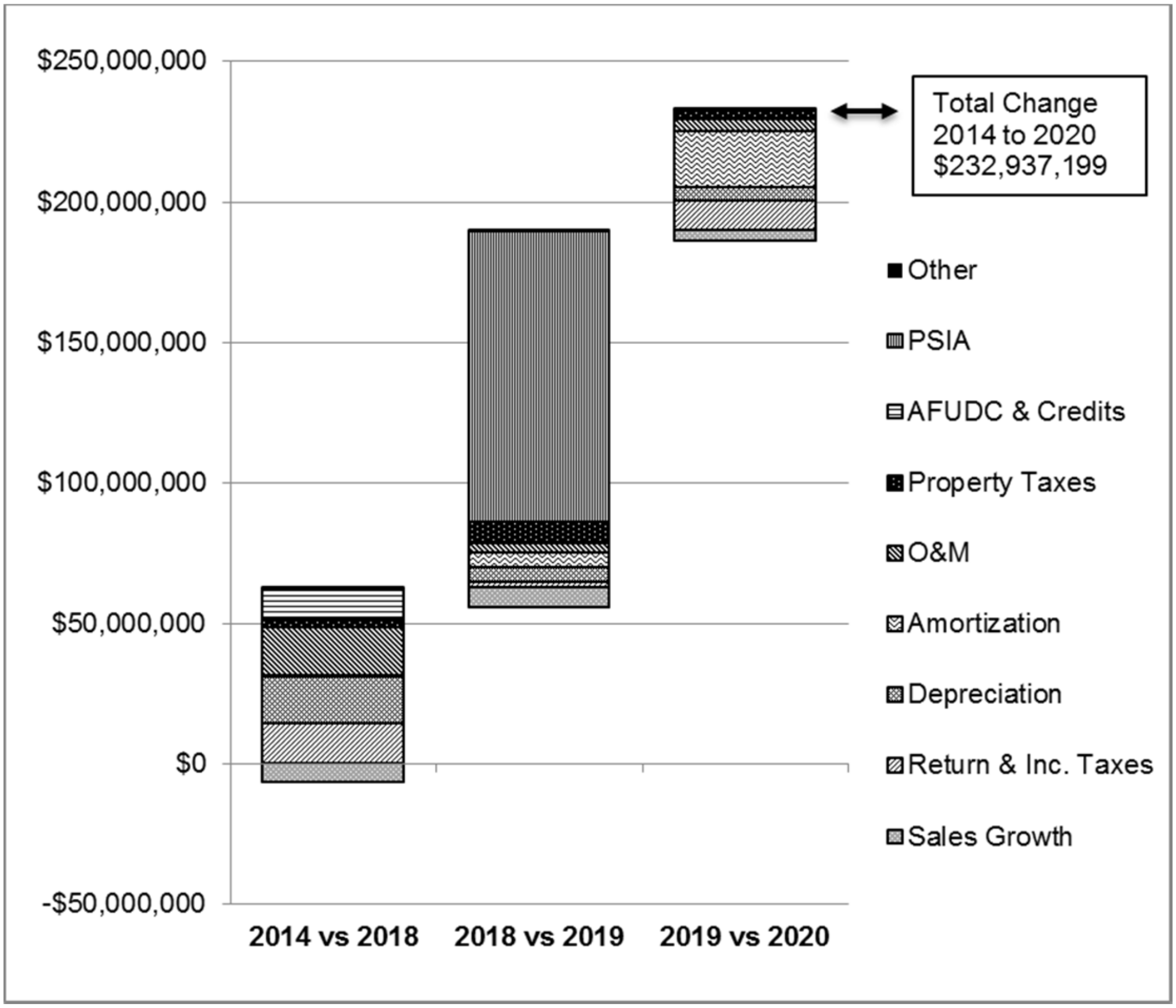
A. As mentioned previously we have a substantial current deficiency, as evidenced by our recent earnings history. Even with the mitigation measures described above, we are faced with a 2018 revenue deficiency of over $63 million. These deficiencies are expected to grow in 2019 and 2020.

The drivers of the deficiencies are summarized in Table SBB-D- 8 and Figure SBB-D- 4.

Table SBB-D- 8

	2014 vs 2018	2018 vs 2019	2019 vs 2020	Total Increase 2014 vs 2020
Change in Total Revenue	($713,985)	($7,141,600)	($3,760,035)	($11,615,620)
Return & Inc. Taxes	$16,314,959	$15,724,201	$11,487,351	$43,526,511
Depreciation & Amortization	$17,915,451	$7,062,543	$5,316,621	$30,294,614
Amortization of Regulatory Assets	$484,959	$5,727,240	$21,638,926	$27,851,126
O&M	$19,003,621	$3,316,416	$4,633,693	$26,953,730
Property Taxes	$2,972,800	$8,117,472	$3,485,273	$14,575,545
AFUDC	6,596,763	$0	$0	$6,596,763
PSIA	$0	$93,883,036	$0	$93,883,036
Other	$620,692	$137,629	$113,174	$871,495
TOTAL	$63,195,261	$126,826,936	$42,915,002	$232,937,199

Figure SBB-D- 4



To explain these drivers I would begin with two important observations. First, about 40 percent of the total base rate deficiency over the MYP period of $233 million is attributable to the roll-in of the PSIA in 2019, which is revenue-neutral to customers. The net revenue deficiency after adjusting for this roll-in is about $139 million.

Second, capital costs are driving this net deficiency of $139 million. Revenue growth reduces the deficiency by about $11.6 million. Consequently, growth in O&M expenses, capital costs and other components of the revenue requirement are projected to increase by about $151 million from 2014 through 2020. The contribution of O&M expense to this $151 million is about $27 million, These amounts demonstrates the disproportionate contribution of capital costs to the MYP deficiency. Even though O&M expenses were approximately 45 percent of our most recently approved HTY cost of service (2014 HTY), O&M expenses contribute only about 18 percent of the MYP deficiency. The remaining deficiency is due to amortization of regulatory assets and capital costs. Amortizations contribute another 18 percent of the deficiency, and capital costs contribute the remaining 63 percent.

Q. WHY DO YOU CHARACTERIZE THE OTHER DRIVERS OF THE DEFICIENCES AS CAPITAL-RELATED COSTS, SINCE TWO OF THE DRIVERS ARE PROPERTY TAXES AND INCOME TAXES?

A. These two taxes are closely correlated with our plant balances. Income tax is assessed on earnings, and for a regulated utility test-year earnings are the authorized ROE times the rate base. Similarly, as Company witness Paul Simon explains in his Direct Testimony, property taxes are largely driven by plant balances and net income, and net income is closely related to net plant balances.

Q. ARE THE INCREASES IN CAPITAL COSTS DUE SOLELY TO INCREASES IN PLANT BALANCES?

A. No. Changes to the weighted average cost of capital, depreciation rates, and income-tax rates can also affect the capital-related revenue requirements. The revenue deficiencies during the MYP period reflect no changes to state or federal income-tax rates. But the Company is proposing modest changes to both the depreciation rates and weighted average cost of capital approved in our last Phase I proceeding. The remaining impacts on capital costs are due primarily to changes to plant balances (gross and net plant) and other potential drivers

Q. WHAT ARE THESE OTHER POTENTIAL DRIVERS?

A. The return component of capital costs is obviously linked to rate base. While changes to net plant (additions to plant-in-service minus depreciation expense) are the primary drivers of changes to rate base, rate base is also affected by changes to Accumulated Deferred Income Taxes ("ADIT"). While most changes to ADIT follow changes to net plant, ADIT is also affected by Bonus Depreciation provisions and other change to tax depreciation rates. For purposes of my driver analysis I am not addressing separately changes to rate base resulting from changes to tax depreciation provisions. Such impacts will be subsumed in my amounts imputed to changes in plant balances. Nonetheless, in her Direct Testimony Ms. Ostrom does discuss changes to Bonus Depreciation over the MYP period.

Q. BASED ON YOUR CHARACTERIZATION OF MANY OF THE COST DRIVERS PROVIDED IN Table SBB-D- 8 **AS CAPITAL-RELATED, CAN YOU PROVIDE A SIMPLIFIED VERSION OF THIS Table SBB-D- 8?**

A. Yes. In Table SBB-D- 9 below I net out the impacts of sales growth, the PSIA roll-in and AFUDC, and break down the drivers of the resulting net deficiency into three categories: O&M, capital-related costs, and amortizations.

Table SBB-D- 9

	2014 vs 2018	2018 vs 2019	2019 vs 2020	Total Increase 2014 vs 2020
Total Year Over Year Change In Rev. Req.	$63,195,261	$126,826,936	$42,915,002	$232,937,199
Sales Growth	($713,985)	($7,141,600)	($3,760,035)	($11,615,620)
PSIA Impact		$93,883,036		$93,883,036
AFUDC	$6,596,763			$6,596,763
Deficiency Net of Sales, PSIA, & AFUDC Impacts	$57,312,482	$40,085,500	$46,675,038	$144,073,020
% Contribution of O&M	33.2%	8.3%	9.9%	18.7%
% Contribution of Amortizations	0.8%	14.3%	46.4%	19.3%
% Contribution from Capital Related Items	64.9%	77.1%	43.5%	61.4%

Q. CAN YOU DISAGGREGATE THE CAPITAL COST CATEGORY INTO THE DRIVERS DISCUSSED ABOVE?

A. Yes. The drivers of the higher capital costs are provided in Table SBB-D- 10 below.

Table SBB-D- 10

	2014 vs 2018	2018 vs 2019	2019 vs 2020	Total Increase 2014 vs 2020
Return & Income Taxes	$16,314,959	$15,724,201	$11,487,351	$43,526,511
Depreciation	$17,915,451	$7,062,543	$5,316,621	$30,294,614
Property Taxes	$2,972,800	$8,117,472	$3,485,273	$14,575,545
Total Capital Related Items	$37,203,210	$30,904,215	$20,289,244	$88,396,670
Impact of Change in WACC	$3,963,530	($471,059)	$752,961	$4,245,432
Impact of Change In Depreciation Rates	($6,619,367)	$1,239,798	$711,781	($4,667,788)
Impact due to Changes in Net Plant	$39,859,047	$30,135,476	$18,824,503	$88,819,026
Total Capital Related Items	$37,203,210	$30,904,215	$20,289,244	$88,396,670

The upshot is that plant additions are driving the bulk of the cost changes during the MYP period. I will highlight the major projects that contribute to higher plant balances later in this section of my testimony.

Q. CAN YOU ELABORATE ON THE SPECIFIC DRIVERS FOR THE THREE DIFFERENT PERIODS COVERED IN THE TABLE AND CHART?

A. Yes. I will cover the high points, and liberally cite the more detailed explanations that other Company witnesses provide.

B. Drivers of Deficiency 2014 to 2018

Q. WHAT ARE THE MAIN DRIVERS OF THE INCREMENTAL DEFICIENCY IN 2018?

A. Revenue growth has a small impact of ($714,000). During this period use per customer generally fell or is projected to fall, but customer growth has been or will be high enough to generate modest revenue growth. Ms. Marks discusses these trends in sales and customer numbers in more detail in her Direct

Testimony. In addition, other revenues are projected to decline. The net effect is a revenue gain between the 2014 HTY and 2018 of less than $1 million.

Likewise, changes to amortization have a very small impact -- about $0.5 million. This impact is depressed by the Company's proposed rate mitigation measures explained earlier.

The deficiency after netting out revenue growth and amortizations is $69.2 million. This is the only period for which O&M expenses are an important driver, as they account for about 27 percent of the cost increase from 2014 to 2018.

Q. WHAT ARE THE MAIN DRIVERS OF THIS INCREASE IN O&M EXPENSE?

A. Ms. Campbell breaks down the increase in O&M expense from the 2014 HTY to 2016 at Pages 83 of her Direct Testimony. The increase from 2016 to 2018 is based on changes to forecasted O&M expenses during that period (Emergency Response and pension and benefits expenses) and one year of O&M escalation (applied to the remaining expenses) at 2 percent for labor expenses and 0 percent for non-labor expenses. The combined increase is about $19 million.

Q. WHAT ARE THE DRIVERS OF THE REMAINING 73 PERCENT OF THE COST INCREASES?

A. There are two drivers. The first is a change to the treatment of Construction Work in Progress ("CWIP") during the 2014 HTY and 2018 FTY. Changes in capital costs attributable to plant additions account for the bulk of the remaining deficiency.

Q. WHY IS THERE A DIFFERENCE IN THE TREATMENT OF CWIP BETWEEN THE 2014 HTY AND THE 2018 FTY?

A. In the HTY the Company included a CWIP return at the WACC with an AFUDC offset. In the 2018 FTY the Company excludes CWIP completely. The impact of this varying CWIP treatment is the CWIP balance times the difference between the WACC and AFUDC rates. That amount is $6.6 million. This impact is limited to the 2018 deficiency, since all three FTYs exclude CWIP.

The capital-related cost increase, net of the CWIP impact discussed above, is almost $31 million.

Q. WHAT MAJOR PROJECTS HAVE BEEN OR WILL BE PLACED IN SERVICE AFTER 2014 AND THROUGH 2018?

A. Since the PSIA will be effective through 2018, the capital additions driving the additional $31 million of capital-related base costs in the business are attributable to non-PSIA investments. The total capital expenditures for these initiatives from 2015 through 2018 are about $715 million. The mail driver of these capital expenditures is new business.

In addition, the WAM/GL project will be completely in-service by 2018. The total capital expenditure of this project allocated to the gas department is about $45 million, and represent another important driver of the capital-related cost increase from 2014 through 2018.

B. Drivers of Deficiency 2018 to 2019

Q. WHAT ARE THE MAIN DRIVERS OF THE INCREMENTAL DEFICIENCY IN 2019?

A. As shown in Table SBB-D- 8, Table SBB-D- 9, Table SBB-D- 10 the incremental 2019 deficiency net of the PSIA roll-in at 2018 levels is about $33 million. Adding the revenue increase of $7 million results in a cost increase of about $40 million. Of this increase, about $3.3 million or 8 percent is attributable to O&M expense; about $5.7 million or 14 percent is attributable to the amortization of regulatory assets; and about $31 million or 77 percent is attributable to capital costs driven by plant additions.

Q. WHAT DRIVES THE REVENUE INCREASE?

A. The increased revenue of $7 million is primarily attributable to growth in residential sales. While average use per customer is expected to decrease, a 1.2 percent growth in the total number of residential customers generates these higher revenues. Revenues from other classes and revenue from miscellaneous services such as connection charges and late payment fees are expected to be relatively flat from 2018 to 2019.

Q. WHAT FACTORS DRIVE THE INCREASES IN O&M AND AMORTIZATION EXPENSES?

A. The increase in O&M expense is attributable to the application of the escalators explained previously and the net changes to the forecasted expenses –

Emergency Response and pension and benefits expense. The impact is relatively modest, about 1.5 percent.

Mr. Berman and I have explained the increase in the amortization of regulatory assets. This increase is less than it otherwise would be due to the Company's proposed rate mitigation.

Q. WHAT PLANT ADDITIONS DRIVE THE INCREASE IN CAPITAL COSTS?

A. The capital expenditures for the gas department (excluding common plant) in 2019 are a good barometer of the plant additions driving this increase. These capital expenditures total $274 million. The main components are provided below.

New Service	$35.8 million
Asset Health	$25.8 million
Mandates	$11.4 million
Equipment Purchases	$26.0 million
Tungsten to Blackhawk	$10.8 million
Accelerated Main Replacement	$38.3 million
Distribution Integrity Management	$40.6 million
Transmission Integrity Management	$73.9 million

Capital expenditures on integrity projects contribute to the incremental base in 2019, since all PSIA costs would be rolled into base rates as of January 1, 2019.

C. Drivers of Deficiency 2019 to 2020

Q. WHAT ARE THE MAIN DRIVERS OF THE INCREMENTAL DEFICIENCY IN 2020?

A. As shown in Table SBB-D- 8, Table SBB-D- 9 and Table SBB-D- 10the incremental 2020 deficiency is about $43 million. Adding the revenue increase of $3.7 million results in a cost increase of about $46.7 million.

Of this increase, about $4.6 million or 10 percent is attributable to O&M expense; about $21.6 million or 46 percent is attributable to the amortization of regulatory assets; and about $20.3 million or 44 percent is attributable to capital costs driven by plant additions.

Q. WHAT DRIVES THE REVENUE INCREASE?

A. The $3.7 million change in revenue from 2019 to 2020 is attributable to growth in residential revenues. Average use per residential customer is forecasted to be flat between 2019 and 2020, but the total number of residential customers is forecasted to increase by 1.1 percent. Revenues from other classes are expected to be relatively flat from 2019 to 2020, and other revenues from miscellaneous services are also expected to be flat.

Q. WHAT FACTORS DRIVE THE INCREASES IN O&M EXPENSES?

A. As with the 2019 O&M increase, the 2020 increase in O&M expense is attributable to the application of the escalators explained previously and the net changes to the forecasted expenses – Emergency Response and pension expense. Again, the impact is relatively modest.

Q. WHY IS THE AMORTIZATION OF REGULATORY ASSETS SUCH A LARGE DRIVER OF THE 2020 DEFICIENCY?

A. The impact is a direct result of the proposed mitigation measures. As explained previously, the amortization of regulatory asset balances was loaded more heavily into 2020.

Q. WHAT PLANT ADDITIONS DRIVE THE INCREASE IN CAPITAL COSTS?

A. The Company projects $280.4 million of capital expenditures for the gas department (excluding common plant) in 2020. The major components are provided below:

New Service	$40.4 million
Asset Health	$26.4 million
Mandates	$12.5 million
Equipment Purchases	$26.6 million
Ganby Take Off	$8.6 million
Accelerated Main Replacement	$38.3 million
Distribution Integrity Management	$40.6 million
Transmission Integrity Management	$73.9 million

X. DISCUSSION OF VARIOUS COST OF SERVICE INPUTS

A. Proposed Financing Parameters

Q. WHAT RETURN ON EQUITY IS THE COMPANY SEEKING IN THIS PROCEEDING?

A. As Mr. Reed supports in his Direct Testimony, the Company is requesting an ROE of 10.0 percent. This proposed ROE is fixed for 2018. But as mentioned above, the Company requests approval to adjust the ROE in 2019 and 2020 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index from the time the formula is implemented to the end of each test year in the MYP. Mr. Reed explains this proposed adjustment in his Direct Testimony.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE PROPOSED ROE?

A. I have nothing to add to Mr. Reed's analysis, but wish to stress that regulatory commissions are usually presented with a range of proposed ROEs by various experts. In this proceeding, I believe Public Service should be authorized an ROE close to the top of whatever range the Commission deems reasonable for two reasons. First, as demonstrated through our testimony and attachments in this filing, we have demonstrated very good performance relative to other local distribution companies; we offer customers great value for the money. Second, we are willing to accept asymmetrical risk through an Earnings Sharing Test that caps our effective ROE at 100 basis points above the authorized level while providing us no downside protection.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING FOR THE MYP PERIOD?

A. The Company proposes a capital structure consisting of 55.25 percent equity and 44.75 percent long-term debt. Ms. Schell supports this proposed capital structure in her Direct Testimony.

Q. WHAT COSTS OF DEBT DOES THE COMPANY PROPOSE FOR THE MYP PERIOD?

A. The Company proposes a cost of debt of 4.38 percent in 2018, 4.33 percent in 2019, and 4.36 percent in 2020. Ms. Schell supports these requests in her Direct Testimony.

Q. WHAT OVERALL RATES OF RETURN RESULT FROM THE COMPANY'S PROPOSED ROE, CAPITAL STRUCTURE AND DEBT COSTS?

A. The proposed overall rates of return are 7.49 percent in 2018, 7.47 percent in 2019, and 7.48 percent in 2020. Mr. Berman uses these overall returns to develop his 2018, 2019 and 2020 test-year revenue requirements. Again, this overall return would be adjusted if interest rates change sufficiently in 2019 and/or 2020 to trigger the ROE adjustment that Mr. Reed recommends.

B. Proposed Amortization of Regulatory Assets

Q. PLEASE SUMMARIZE THE DEFERRED COSTS FOR WHICH THE COMPANY REQUESTS COST RECOVERY IN THIS PROCEEDING.

A. The Company requests to amortize and recover (or credit) through the proposed GRSA the balance of the deferred expense balances associated with the Work Asset Management Cost capital costs, property taxes, the Enhanced Emergency Response Program, the Damage Prevention Program, pension and benefits expense and the environmental clean-up costs at a site in Boulder. In each case the balance to be amortized will be the projected balance as of December 31, 2017. As explained earlier, to smooth out the annual bill increases under the MYP the Company proposes to amortize the deferred balance for these regulatory assets over the 24 months from January 1, 2019, through December 31, 2020. All of the balances are expected to be positive (i.e., a regulatory asset) except for pension and benefits expense, which will be a negative amount (i.e., a regulatory liability). As referenced in Mr. Berman’s Direct Testimony, the projected net deferred balance is $32.65 million.

All of these deferrals were approved in the Company’s 2015 Phase I rate case or, in the case of the clean-up costs at the Boulder site, through previous Commission Decisions.

Mr. Berman provides an explanation of these deferred costs in his Direct Testimony.

Q. IS THE COMPANY REQUESTING TO EARN A RETURN ON THESE REGULATORY ASSETS OR LIABILITIES?

A. Yes. The Company proposes to earn a return at our Weighted Average Cost of Capital ("WACC") on all of the balances except for the deferred pension expense.

Q. WHY IS THE COMPANY REQUESTING A RETURN ON THESE BALANCES?

A. These balances represent amounts on our balance sheet for which the Company either receives no recovery from customers (in the case of regulatory assets) or does not credit customers (in the case of regulatory liabilities) until the balances are amortized and recovered through rates. In that respect these balances are no different from other assets that are on our books and contribute to or subtract from rate base. There are no statutes or rules that either require or prohibit the application of a return on regulatory assets or liabilities. But from a policy perspective the Company believes regulatory assets require financing – just as do other components of our rate base. Since the Company earns our WACC on these other components, we should also earn the WACC on regulatory assets. Similarly, the credits to customers for regulatory liabilities should also include a return at the WACC.

Q. ARE THERE ANY OTHER ADVANTAGES OF APPLYING THE WACC TO REGULATORY ASSET BALANCES AND LIABILITIES?

A. Yes. In this proceeding the Company proposes to smooth out the rate increases over the MYP period by deferring the amortization of the legacy regulatory assets. Earning a return at the WACC on unamortized regulatory balances facilitates such deferrals, as this return eliminates the financial penalty of deferring recovery. Likewise, the application of a full WACC return would also facilitate a deferral of the amortization of regulatory liabilities if needed in the future to mitigate rate increases – since customers would also be compensated at the WACC.

Q. WHY IS THE COMPANY REQUESTING AMORTIZATION PERIODS FOR THE DEFFERED COSTS THAT END IN DECEMBER 2020?

A. The Company's approach is to complete the amortization of the costs by the date on which new base rates are expected to be implemented as a result of the next Phase I proceeding. Under this approach, regulatory assets and liabilities are disposed of relatively quickly and do not span multiple rate cases, which can result in the "pancaking" of multiple regulatory assets or liabilities incurred over many years. Of course, deferred balances that reach unusually high levels may require longer amortization periods. But the Company does not believe the net balance of the deferred costs at issue in this proceeding is of that magnitude.

C. Proposed Return on Prepaid Pension Assets and Other Regulatory Assets

Q. WHAT RETURN DOES THE COMPANY CURRENTLY EARN ON THE PREPAID PENSION ASSET ALLOCATED TO THE GAS DEPARTMENT?

A. The Company currently earns a debt return, per Decision No. C16-0123 in the 2015 Phase I rate case.

Q. IS THE COMPANY PROPOSING TO EARN ITS WACC ON THE PREPAID PENSION ASSET ALLOCATED TO THE GAS DEPARTMENT?

A. Yes.

Q. WHY IS THE COMPANY ASKING THE COMMISSION TO REVISIT ITS PREVIOUS DECISION?

A. The Company obviously places great weight on Commission decisions and precedent. However, it is important to remember that the Company was allowed a WACC return on our prepaid pension asset in all previous gas Phase I proceedings since 1993. In every Public Service gas rate case following, the Commission continuously reaffirmed its policy of approving a WACC return on our prepaid pension asset for setting base rates for the Company -- until the 2015 Phase I rate case. So we are by no means requesting a revision to long-standing Commission precedent. In fact, the Decision in the last gas Phase I proceeding was a departure from what was – up to that time -- long-standing Commission precedent.

Moreover, the Company strongly believes that we should earn our full WACC on the prepaid pension asset. Mr. Schrubbe and Mr. Wickes provide extensive justification for the Company's request in their Direct Testimony. I only wish to point out that the Company's proposal is consistent with our broader position that assets and liabilities on our balance sheet should be afforded a return at our WACC unless a compelling case can be articulated for different treatment. The Company knows of no compelling reason in the case of either regulatory assets (or liabilities) or prepaid pension assets (or liabilities) for different treatment.

Q. IS THE COMPANY REQUESTING SIMILAR TREATMENT OF THE PREPAID OTHER POST-EMPLOYMENT BENEFITS ("OPEB") ASSETS?

A. Yes. The Company proposes to apply a return at the WACC to these balances as well, for the same reasons described above**.**

D. <u>Rate Case Expenses</u>

Q. WILL PUBLIC SERVICE INCUR RATE CASE EXPENSES TO PREPARE AND PROSECUTE THIS RATE CASE?

A. Yes. Public Service has already incurred rate case expenses to prepare the rate case filing and will continue to incur rate case expenses to perform the other tasks attendant to filing and litigating a base rate case before the Commission. Public Service expects to incur additional rate case expenses as the case progresses.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER THESE RATE CASE EXPENSES IN THIS CASE?

A. Yes.

Q. WHY IS IT APPROPRIATE FOR PUBLIC SERVICE TO INCLUDE RATE CASE EXPENSES AS A RECOVERABLE ITEM IN THE COST OF SERVICE?

A. Most businesses have the flexibility to set their prices based on their assessment of the market and the demand for their products. Utilities that are subject to cost of service regulation do not have this same flexibility, but must instead file for and obtain regulatory authorization to establish new rates. Consequently, the cost of the filing and litigating rate cases are necessary costs of conducting our business. It has been the long-standing practice of this Commission to treat reasonable rate case expense as a necessary cost of doing business and, after review, to allow recovery of rate case expenses through mechanisms established in the same or subsequent proceedings.

Q. WHAT AMOUNT OF RATE CASE EXPENSES IS PUBLIC SERVICE SEEKING TO RECOVER IN THIS CASE?

A. The total cost for consultants, law firms, and other initiatives associated with the rate case is estimated to be $1,073,682, assuming a fully litigated case with a hearing, post-hearing briefing, exceptions and replies to exceptions, and motions for rehearing and replies. Attachment SSB-6 provides a summary of these rate case expenses by major category. Below I will discuss some rate case expense history and explain the major categories of the rate case expenses.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY AMOUNTS OF RATE CASE EXPENSES FROM PRIOR CASES?

A. No. As detailed by Company witness Mr. Berman, the rate case expenses approved for the 2015 Gas Rate Case were to be amortized over a 26-month period, which will end on December 31, 2017. Thus, it is expected that those rate case expenses will be fully amortized prior to rates becoming effective in this rate case, provided the Commission suspends this gas rate case the full 210 days. Mr. Berman's cost of service model reflects this expectation.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY AMOUNTS OF RATE CASE EXPENSES FOR A PHASE II RATE CASE?

A. No. At the time the Company files a Phase II rate case, we will request that the rate case expenses associated with that proceeding be decided and placed into a deferred accounting asset until such time as another Phase I rate case is filed.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR RATE CASE EXPENSE CATEGORIES YOU ARE PRESENTING FOR RECOVERY IN THIS GAS RATE CASE.

A. The major categories of rate case expenses included in my Attachment SBB-6 include the following areas:

Consultants: Consultants are necessary for the preparation of a comprehensive gas rate case for a number of reasons. Many times consultants will testify to or provide support for ROE recommendations, benchmarking analyses, actuarial review of testimony, discovery, or case assembly. Typically, the expertise sought from the consultant is not an expertise that is hired on a permanent basis within the organization.

Transcripts/Hearing Costs: During the course of the case, a court reporter will be necessary to transcribe depositions and hearings before the Commission or ALJ. There is a cost of having court reporters record and then transcribe these proceedings. This fee increases or decreases based upon the timeframe by which the reporter must turn over the transcript.

Legal Counsel: The Company has an in-house legal department whose regulatory team works on the matters that we have before the Commission. However, we have more Commission-related work than can be handled by our in-house department, so we also need to retain outside attorneys for this work. The Company does not staff up its Legal department assuming continuous ongoing rate cases, but we do assign inside attorneys to our rate cases. Our ability to rely on our inside counsel for rate cases is dependent upon other pending matters. Thus, outside legal assistance is necessary.

Postage: We must occasionally mail case materials to intervenors (e.g., Company testimonies, discovery responses, and other materials).

Duplicating and Office Supplies: This category of costs reflects the printing of our filings for internal and external use, as well as other materials necessary for the rate case.

Miscellaneous Expenses: This category captures a variety of items, including travel for Company witnesses to attend the hearing and other meetings, and regulatory support from temporary or hourly employees for the preparation and processing of the case.

Q. PLEASE DISCUSS THE SPECIFIC CONSULTANT AND OUTSIDE WITNESS COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. The costs associated with securing outside consultants or witnesses with specific areas of expertise are necessary for the support and completion of the case. We estimate these costs to be $330,580. This amount is broken down below by consultant, along with a description of the service provided later in my testimony:

PEG (MYP & Gas Benchmarking)	$129,800
Concentric (ROE)	$68,780
Janet Schmidt-Petree (consultant through Wilkinson Barker Knauer LLP	$32,250
Towers Watson (Discovery & Actuarial Study)	$58,500
Alliance GC (Gas Depreciation Study)	$18,750
Gene Wickes, Towers Watson (Prepaid Pension Assets)	$22,500
Total	$330,580

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY PEG.

A. PEG was contracted to conduct and present benchmarking studies, provide background information on MYPs, assist with and assess the Company's proposed MYP, develop an O&M expense escalator, and assess the efficiency impacts of HTYs. Because of the scope of the requested work, the complexity of the econometric benchmarking studies, the need for in-depth experience with MYPs in the U.S. and other countries, and the need for work products to be developed quickly, the Company could not rely on in-house resources.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY CONCENTRIC.

A. In any Phase I rate case ROE and capital structure are critical issues. The witness developing the ROE recommendation must be experienced and able to explain the analysis clearly. Furthermore, while the Company does file rate cases in multiple jurisdictions, we do not maintain the expertise required of an ROE witness in-house. Consequently, we must hire a consultant to provide the analysis and testimony. The Company does not hire an internal witness for this area of expertise because it is a specialized field, and we have found that regulatory commissions generally prefer that we engage an external consultant to provide these services. Additionally, external experts generally have a broader view of developments in their areas of expertise than internal employees focused on the eight states in which Xcel Energy operates.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY TOWERS WATSON.

A. Towers Watson is Xcel Energy's outside consultant for evaluating our pension and benefits programs and the accounting for those programs. They have recently been asked to help respond to discovery regarding the pension program and provide the actuarial studies on pension and benefits to support our test-year expenses. We anticipate needing their services for the discovery process as well in this rate case.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY JANET SCHMIDT-PETREE.

A. The Company contracted with Ms. Schmidt-Petree to prepare testimony. She has extensive knowledge of our Cost Allocation and Assignment Manual and the Fully Distributed Cost Study. Also, due to her prior employment with the Company, she has extensive experience with the transition from the JDE system to SAP.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY ALLIANCE GC.

A. Alliance was contracted to complete the Gas Depreciation Study. These studies require specialized expertise and an immense amount of work; therefore, it is more cost-effective to use outside consulting than maintaining in-house resources.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY MR. WICKES.

A. Similar to many of the consultants discussed above, Mr. Wickes was contracted because he possesses specific expertise that is not cost-effective to retain on a full-time basis in-house. He and his firm have completed the Prepaid Pension Asset analysis for the Company's rate case and Mr. Wickes provides testimony on this subject.

Q. PLEASE DISCUSS THE TRANSCRIPT AND HEARING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. The Company anticipates to incur a total cost of $16,352 for the purchase of transcripts of the hearings and other hearing costs.

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. Outside Legal costs are estimated to be $638,000 and are separated across three law firms where we have hired specific assistance for our rate case filing. The three law firms are Wilkinson Barker Knauer, LLP, Briggs and Morgan, and Winstead PC. Each of these firms was retained for its expertise and specific knowledge of the Xcel Energy companies and, in most cases, Public Service. The firms provided, or will provide, assistance in assembling testimony and attachments, witness preparation, advice on strategy, responding to discovery, and generally processing the case.

The Company's legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative.

Q. PLEASE DESCRIBE THE COSTS INCURRED TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION.

A. Pursuant to Rule 1207 of the Commission Rules of Practice and Procedure, the Company must provide notice to its customers of the proposed rate change, tariff changes, and the impacts on the customer. The costs estimated for completing this requirement are $50,525. This cost can be broken down into two categories – bill onsert/online media and newspaper. The bill onsert/online media component of this category of rate case expense is $20,541 which is the cost associated with printing the notice on a customers' bills, and mailing it to customers during their normal billing cycles. The newspaper component of this category of rate case expense is $29,984. This expense is to fulfill the requirement that we post the notice of our filing in a newspaper of general circulation for two consecutive Sundays. The Company will again contemporaneously file in this proceeding a motion for Alternative Form of Notice (AFN) requesting Commission approval of our request. By granting this request, the Company and customers have realized significant savings.

Q. PLEASE DISCUSS THE POSTAGE COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. We are estimating that we will incur approximately $500 in postage expenses throughout the case. These are costs associated with providing materials such as discovery responses to intervening parties through the United States Postal Service delivery or direct shipping. If materials need to be mailed to an intervener, the Company prefers to use the United States Postal Service delivery. But in some cases the only means of timely delivery is direct shipping.

We again plan to use the SharePoint site to provide access to discovery responses, attachments, work papers, testimony, and some settlement materials.

Not only will this reduce postage costs to practically $0, it will allow interveners located at a more distant location to more timely access the information.

Q. PLEASE DESCRIBE THE COSTS INCURRED ASSOCIATED WITH THE PRINTING AND PROVISION OF HARD COPIES OF CASE MATERIALS.

A. Both at the onset of the case and throughout the case, the Company will provide paper copies to various parties as well as to Company witnesses. The costs incurred for this activity are estimated to be $1,500 -- $1,000 for duplication and $500 for supplies.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. Miscellaneous expenses cover travel expenses for out-of-state witnesses and communications with our employees regarding the rate case and regulatory support. The total amount requested for this category is $36,225, which is broken down into sub-categories below.

Communications – Webcast	$1,950
Employee Expenses (e.g. Travel)	$24,675
Regulatory Support	$9,600
Total	$36,225

The two most significant subcategories in this major cost category are the Employee Expenses and the Regulatory Support. The Employee Expenses subcategory reflects travel expenses for individuals who do not reside in

Colorado. They must travel to provide testimony at the hearing, meet with interveners, and participate in other preparatory sessions as needed.

Q. DO YOU BELIEVE THAT THE COSTS DESCRIBED ABOVE ARE REASONABLE?

A. Yes. We have worked diligently to find ways to reduce these rate case expenses, such as the AFN, changes in Outside Legal assignments, and bidding out our ROE witness activities. Where we do not have historical information to aid in cost estimations, we used rate case expenses incurred in previous rate cases that were either settled or litigated over a long period and involved extensive discovery.

E. <u>Gains/Losses on Asset Sales</u>

Q. DID THE COMPANY REALIZE ANY GAINS OR LOSSES FROM ROUTINE ASSET OR LAND SALES FOR WHICH IT SEEKS ACCOUNTING TREATMENT IN THIS PROCEEDING?

A. Yes. On January 6, 2016, Public Service sold property that included land and assets near its Cabin Creek hydro-electric plant in Georgetown, Colorado. The sale resulted in a net gain. Of the total gain, $53,258 is attributable to the sale of depreciable assets included in rate base.

Q. PLEASE DESCRIBE THE PROPERTY.

A. The property is a legacy property originally purchased and owned by the Green and Clear Lakes Company in the late 1800s. Green and Clear Lakes Company's holdings included multiple storage reservoirs and land near Public Service's

Cabin Creek hydro-electric plant. United Hydro Electric Company ("United Hydro") acquired the Green and Clear Lakes Company in 1906. United Hydro merged into Public Service Company of Colorado in 1941, and the Green and Clear Lakes Company became a direct subsidiary of Public Service.

The property formerly owned by the Green and Clear Lakes Company includes, among other things, land adjacent to Green Lake, a conference center, a caretaker's lodge, and a recreational easement. Several years ago, the Company determined that portions of the property previously owned by the Green and Clear Lakes Company no longer served utility operations and decided to sell it. The property at issue ("Green/Clear Lakes property") consists of 126.8 acres of land subject to a recreational easement, a conference center, and a caretaker's lodge.

Q. YOU MENTIONED THERE WAS A GAIN ON THE SALE OF THE GREEN/CLEAR LAKES PROPERTY. CAN YOU EXPLAIN WHAT A GAIN ON SALE IS?

A. Yes. A utility receives a gain on sale when it sells an asset such as land or equipment at a price higher than the acquisition cost of the non-depreciable asset or the depreciated book value of the depreciable asset. Non-depreciable assets (e.g., land or water rights) and depreciable assets (e.g., equipment or buildings) are thus treated differently when determining whether there is a gain from the sale of these assets.

Q. PLEASE EXPLAIN THIS DIFFERENCE.

A. A utility depreciates certain assets like buildings, machinery, and equipment. Depreciation is the cost of owning an asset that appears on the utility's books each year. By depreciating an asset over its useful life a utility can allocate the original cost of an asset across the period over which the asset provides service to customers. In turn, customers reimburse the utility for this depreciation expense through their rates. When a utility sells the depreciable asset, the gain is the difference between the depreciated value of the assets at the time of sale and the sales price, minus applicable acquisition and closing costs.

Land, however, is not a depreciable asset. Unlike equipment, software and other assets, land does not need to be replaced. Accordingly, while customers pay the carrying costs of non-depreciable assets, the Company's shareholders are not reimbursed for their investments in land rights until or unless the land (or other non-depreciable asset) is sold.

Q. HOW HAS THE COMPANY ACCOUNTED FOR THE GREEN AND CLEAR LAKES PROPERTY?

A. The conference center and the caretaker's lodge are in the Company's rate base, while the land is not. The Company has accounted for its $22,035 of non-utility investment in the land and recreational easement as an investment in a subsidiary (Green and Clear Lakes Company). However, the Company has included the buildings on the land in its utility rate base as common plant assets. The original cost of these assets is $190,090, and the associated depreciation is

$105,531, which results in a total net book value of the depreciable property of $84,559.

Q. HOW MUCH DID THE GREEN AND CLEAR LAKES PROPERTY SELL FOR?

A. The total sale price was $728,100, with a total net purchase price of $682,654 after closing costs. Based on an appraisal of the property completed in 2012, approximately 60 percent of the net proceeds ($410,958) are attributable to land and approximately 40 percent ($271,696) are attributable to the equipment and buildings, i.e., depreciable assets.

Q. WAS THE SALE PRICE REASONABLE?

A. Yes. The value of the land adjacent to Green Lake appraised at $415,000, and the value of the conference center and caretaker's lodge appraised at $275,000, for a total appraised value of $690,000. The Company's total sale price was nearly $40,000 above the appraised value, which indicates that the sale price was indeed reasonable.

Q. HAS THE COMMISSION ADOPTED A UNIFORM APPROACH AS TO HOW IT TREATS GAINS OR LOSSES ON ROUTINE LAND OR ASSET SALES?

A. No. Although the issue has risen on a number of occasions, I am unaware of any policy. The Commission has historically addressed the issue on a case-by-case basis. Moreover, I do not believe that there is any uniform regulatory practice on the treatment of such gains or losses by other state regulatory commissions.

Q. HOW IS THE COMPANY PROPOSING TO TREAT THE GAIN ON SALE OF THE GREEN/CLEAR LAKES LAND AND ASSETS?

A. The Company proposes to retain the full gain on sale of the associated land, which has never been included in rate base. With respect to the depreciable assets included in rate base, the Company proposes to share 50 percent of the gain on sale with customers, which amounts to $26,629 as reflected in Mr. Berman's Attachments SPB-1 through SPB-4, Schedule 52. The asset sale adjustment represents a one-time sharing of the gain on the sale. Consequently, the adjustment is confined to the 2016 HTY and 2018 FTY.

Q. WHAT IS THE COMPANY'S RATIONALE FOR THIS SHARING?

A. Fundamentally, the allocation of proceeds from a routine sale is a question of equity. Since the Green/Clear Lakes land has been owned by a subsidiary and excluded from rate base, the gain from the sale of land should be retained by shareholders.

In contrast, the Green/Clear Lakes assets (i.e. conference center and lodge), have been included in rate base and are depreciable assets, meaning both customers and shareholders have born capital risk associated with these assets. Public Service therefore recommends that the gain be split equally between customers and shareholders.

Q. IS THE COMPANY RECOMMENDING THAT THE COMMISSION'S TRATMENT OF THE GREEN/CLEAR LAKES PROPERTY ESTABLISH ANY PRECEDENT FOR FUTURE SALES?

A. No. The Company proposes the equal sharing of the gain on the Green/Clear Lakes depreciable assets as a reasonable resolution in this specific case only.

Nonetheless, the Company does support the development of a consistent Commission policy regarding the treatment of gains and losses on routine asset and land sales in the future; such a policy would provide regulatory certainty and potentially minimize disputes. But because this proceeding involves one small sale, it is probably not the best venue for policy discussions. In our upcoming Phase I electric filing the Company will be addressing a greater number of such asset and land sales. The Company anticipates that we will propose a policy for the Commission's consideration in that filing.

F. <u>Craig & Gunnison Compressors</u>

Q. IS PUBLIC SERVICE REQUESTING TO ADD ANY NEW RATE BASE ITEMS THAT ARE USED TO SERVE LOCAL DISTRIBUTION COMPANIES?

A. Yes. The 2018, 2019, and 2020 revenue requirements, presented by Mr. Berman in Attachments SPB-1, 2 and 3, include the cost of the new Craig compressor station that will be used by Public Service to serve Atmos (an LDC) in the Steamboat area. The station is currently under construction and due to be in-service in November 2017. This 2019 and 2020 revenue requirements also include the cost of the new Gunnison compressor that will serve Atmos in the

Gunnison and Crested Butte areas. Company witness Cheryl Campbell discusses why these new compressor stations are needed and their expected costs.

On March 28, 2016, the Company filed an amendment to the firm transportation service agreement with Atmos in Miscellaneous Proceeding No. 10M-343G. This filing explains that Atmos will have an incremental service charge added to its monthly bill associated with the Craig compressor in accordance with Public Service's extension policy for LDC customers, as specified on Pages R49 and R50 of its Natural Gas Tariff. On May 19, 2017, the Company submitted a similar filing for the Gunnison Compressor in the same proceeding.

Q. WHY HAS PUBLIC SERVICE INCLUDED THE COSTS OF THE CRAIG AND GUNNISION COMPRESSOR IN ITS REVENUE REQUIREMENT?

A. Public Service is requesting that the cost of the Craig and Gunnison compressors be added to our overall cost of service in this proceeding. The treatment of extensions and reinforcements for LDC customers was modified in Public Service's last Phase II gas rate case, Proceeding No. 11AL-151G. In a joint settlement approved through Commission Decision No. R11-1134, it was established that cost recovery for equipment associated with LDC extensions or reinforcements would be addressed in future proceedings such as a Phase I rate case[3].

Decision No. C09-0365 in Proceeding No. 08F-033G clarified the character of the service provided to LDC customers. These customers are served on a contract basis and are free to choose an alternative service provider; as such they are not legally entitled to the same rates that our retail customers receive. However in conjunction with the new compressor stations, Atmos has agreed to a ten-year contract extension with Public Service, ensuring that they will remain a part of the Public Service gas delivery system until at least 2028.

The Craig and Gunnison Compressors are needed to ensure reliable natural gas service to Atmos and were identified as the lowest-cost options for providing that service. While the residents and businesses of Steamboat Springs and Crested Butte are not customers of Public Service, the Atmos LDC is our customer and we have a commitment to meet their growing demand for natural gas capacity. The Craig and Gunnison compressor stations will be used and useful in November 2017 and December 2018, respectively. The question before Commission is how to recover the costs of these investments.

Q. WHAT COST RECOVERY DOES PUBLIC SERVICE PROPOSE?

A. Public Service is requesting that the residents of Steamboat, Crested Butte, Gunnison and other areas served by Atmos not be burdened with the entire cost of the compressors. Instead, these compressors should be treated similarly to

[3] See September 19th 2011 Stipulation and Agreement in Resolution of Proceeding, No. 11AL-151G, pages 17 & 18.

other assets that are added to increase the capacity of our natural gas transmission system.

Accordingly, the 2017, 2018, and 2019 revenue requirements presented by Mr. Berman do not include any revenues associated with the Craig and Gunnison incremental service charges to Atmos.

Q. WHY IS THE COMPANY PROPOSING TO RECOVER THE COSTS OF THESE COMPRESSORS FROM THE BROAD BODY OF CUSTOMERS?

A. Atmos currently pays the standard TFL rate. This rate is designed to recover from transportation customers their allocated share of the costs of the entire Public Service system – including the cost of significant transmission infrastructure in the Front Range that is not used to serve the Steamboat area that Atmos serves. As such, Atmos' customers have been contributing to the costs to serve Front Range customers since Atmos became an LDC customer of Public Service. Consequently, as a matter of equity Public Service believes that the cost of the Craig and Gunnison compressors should be shared by the broad body of customers and not recovered from Atmos through a separate assessment.

If the Commission agrees with the Company's proposal, we will amend our transportation agreements with Atmos to remove those charges from their monthly TFL bills.

Q. WHAT WOULD BE THE IMPACT OF THE COMPANY'S PROPOSED TREATMENT OF THE COMPRESSOR COSTS?

A. The incremental service charge would generate annual revenue of $1,035,353 for Craig and $517,112 for Gunnison. This combined total revenue requirement of $1,552,465 translates to an incremental GRSA of approximately 0.40 percent[4]. An incremental GRSA of 0.40% translates to an average monthly bill impact of 0.15 percent, or seven cents ($0.07), on a typical Public Service residential customer.

Q. WHAT WOULD BE THE IMPACT TO ATMOS' CUSTOMERS SHOULD THE COMMISSION ORDER THE COMPANY TO DIRECTLY ASSESS THE COSTS TO ATMOS?

A. Because Atmos serves significantly fewer customers in Colorado than Public Service, the impacts of the incremental service charge would be much greater. Attachment SBB-7 was provided by Atmos and demonstrates that the typical residential customer would experience a bill increase of 4.5 percent, or $2.44 per month, as a result of the Craig compressor incremental service charge. That impact is about 3500 percent greater than the impact on Public Service's customers of recovering the compressor costs through the Company's base rates.

[4] $1,552,465÷$390,000,000 = 0.40%

G. <u>Treatment of Residential Late Payment Fees</u>

Q. HOW IS THE COMPANY PROPOSING TO TREAT ITS PROJECTED RESIDENTIAL LATE-PAYMENT FEE REVENUES?

A. The Company currently donates 100 percent of our residential late-payment fee ("LPF") revenues to Energy Outreach Colorado ("EOC"). In this proceeding the Company is proposing to continue those donations consistent with past practice. Accordingly, the residential LPF revenues have not been credited to the cost of service.

XI. PROPOSAL TO DEFER COSTS DURING MYP PERIOD

Q. YOU HAVE EXPLAINED THE PROPOSED TREATMENT OF COSTS PREVIOUSLY APPROVED FOR DEFERRAL. DOES THE COMPANY ALSO PROPOSE COST DEFERRALS DURING THE TERM OF THE MYP?

A. Yes. The Company proposes deferrals for the following expenses from 2018 through 2020: property taxes, Damage Prevention expenses, pension and benefits expense, environmental clean-up costs at a site in Boulder, and expenses related to potential PHMSA regulations.

Since the proposed GRSAs are based on forecasted property taxes and pension expense in 2018, 2019 and 2020, these forecasts will be the base amounts around which the deferrals will be derived. In contrast, the proposed GRSAs are based on 2016 Damage Prevention expenses of $12,763,072. Consequently so the 2018, 2019 and 2020 deferrals of these expenses will be calibrated to this historical amount. Since the potential expenses resulting from new PMHSA rules are still subject to considerable uncertainty, the Company includes no such expenses in our proposed rates during the MYP period. Likewise, the Company includes no such expenses for clean-up costs at the Boulder site. Instead, the Company seeks approval to defer 100 percent of any such expenses during the MYP period, if and when they are actually incurred, for future recovery.

Mr. Berman and Mr. Litteken provide more detail on these requested ongoing deferrals.

Q. WHY IS THE COMPANY SEEKING DEFERRAL OF THESE SPECIFIC EXPENSES?

A. An MYP reduces the need for deferrals; we are requesting deferrals only to the extent the expenses have a high probability of varying from forecasted levels. As the Commission has found in previous cases, property taxes and pension expense can demonstrate such variability. In fact, under our current electric MYP we continue to defer these costs on an ongoing basis. Mr. Litteken explains why Damage Prevention costs are variable and why the expenses arising from future PHMSA rules are uncertain and potentially significant.

Q. IF THE POTENTIAL PHMSA RULES ARE SO UNCERTAIN, WHY DOES THE COMPANY REQUEST APPROVAL TO DEFER THE ASSOCIATED COSTS?

A. We view this requested deferral as a crucial component of our MYP request. While the timing and scope of PHMSA regulations are uncertain, the potential cost impact on the Company during the MYP period is still significant. Cost trackers are a good way to address potentially significant, uncertain costs that are mostly beyond the utility’s control.

XII. PROPOSED TARIFF CHANGES

Q. IS THE COMPANY SEEKING APPROVAL OF NEW GRSAS IN THIS PROCEEDING?

A. Yes, the Company is proposing revised GRSAs (which are simply adjustments to base rates) for 2018, 2019, and 2020 based on the revenue requirement studies that Mr. Berman sponsors. I am sponsoring the proposed GRSA tariff sheets changes necessary to reflect those rates. Clean versions of these tariff sheets are included as Attachment SSB-8, for the years 2018, 2019 and 2020, respectively.

Q. PLEASE SUMMARIZE THE CHANGES THE COMPANY IS PROPOSING TO THE GRSAS IN 2018, 2019, AND 2020.

A. We propose to raise the GRSA over three years in order to implement the revenue increase indicated by the revenue requirement study in this case. The proposed incremental GRSAs (incremental to the current GRSA) are 16.52 percent for the 2018 FTY, 32.29 percent for the 2019 FTY, and 10.53 percent for the 2020 FTY. Mr. Berman presents the calculation of these GRSA factors based on the requested rate increases in his Direct Testimony. The total GRSAs in the tariff, which reflect the sum of the current GRSA and the incremental GRSAs cited above, are 33.64 percent, 65.93 percent and 76.46 percent, respectively.

Q. IS THE COMPANY SEEKING APPROVAL OF PSIA RATES AS PART OF THIS FILING?

A. No, the Company is not proposing a revised PSIA for 2018 based on the revenue requirement studies sponsored by Mr. Berman. The Company will instead propose 2018 PSIA rates in our November 2017 PSIA filing. The PSIA tariff is currently set to expire after 2018 PSIA costs and revenues are trued up. At which time an Advice Letter would be filed to remove the PSIA tariff.

Q. IS THE COMPANY FILING A NEW TARIFF FOR THE EARNINGS SHARING TEST DESCRIBED ABOVE?

A. Yes. I explained the parameters of the Earnings Sharing Test earlier in my Direct Testimony. The proposed tariff is included as Attachment SBB-8.

Q. IS THE COMPANY PROPOSING TARIFF SHEETS TO MEMORIALIZE THE PROPOSED ADJUSTMENTS FOR MATERIAL CHANGES TO EXPENSES FOR THE ESA?

A. No. The adjustments for material changes to expenses under our current and previous electric MYPs were included in a Commission-approved Settlement Agreement. The Company requests that the Commission approve the adjustments for material changes to expenses that I explained previously, which are provided in Attachment SBB-2.

Q. WHAT IS THE SCHEDULE OF CHARGES FOR RENDERING SERVICE?

A. The Schedule of Charges is a set of charges listed in our gas tariffs for services not covered by our typical rates. The Company provides a wide variety of services to customers upon request or as needed, and assesses charges for those services to the individual customer. Such services include, but are not limited to: instituting or reinstituting service, non-regularly scheduled meter reading, visits from Company technicians to conduct general diagnosis of customer issues, and returned check processing.

Q. IS THE COMPANY SEEKING APPROVAL OF CHANGES TO THE SCHEDULE OF CHARGES AS PART OF THIS FILING?

A. Yes, the Company is proposing to revise the Schedule of Charges to reflect changes in the non-gratuitous labor charges. I am sponsoring the proposed Schedule of Charges tariff sheet changes. Clean versions of these tariff sheets are included as Attachments SSB -8.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE CHARGES FOR RENDERING SERVICE.

A. We propose to increase the charge for most service activities that involve non-gratuitous labor. These moderate increases are based on an updated Agreement between Public Service Company of Colorado and the International Brotherhood of Electrical Workers Local Union 111. Updated vehicular rates also impacted the charges for rendering service.

Q. WILL THE COMPANY BE FILING ANY CHANGES TO THE FRONT RANGE PIPELINE TARIFF?

A. No. The Front Range Pipeline was constructed by the Company in 1999 pursuant to a Certificate of Public Convenience and Necessity (“CPCN”) granted by the Commission in Decision No. C98-556. In that decision, the Commission expressly conditioned its grant of the CPCN authorizing the construction of the Front Range Pipeline and its operation by the Company "on a stand-alone basis." Pursuant to this condition, the Company was required to operate and provide transportation service over the Front Range Pipeline "as separate service from its existing transportation service" and at "stand-alone rates" determined independently from the remainder of the Company's jurisdictional rates and services.

Q. WILL YOU BE SPONSORING ANY ADDITIONAL CHANGES TO THE TARIFFS?

A. Yes, in an effort to promote consistency with the Colorado P.U.C. No. 8 Electric Tariff, the Company is proposing to remove the summation sheets from the Company's Colo. P.U.C. No. 6 Gas Tariff. The Company received approval to remove the electric summation sheets in the Company's last electric Phase II proceeding.[5] This will involve the removal of tariff sheet numbers 10 through 10D and 11 through 11C. The Company proposes to eliminate Summation Tariff sheets, but proposes to comply with PUC rules (4406b) by providing similar information on-line. The Company feels that providing the information on the website is more effective.

[5] (Proceeding No. 16AL-0048E, Decision No. C16-1075)

XIII. COMPLIANCE WITH PRIOR COMMISSION REQUIREMENTS

Q. PLEASE IDENTIFY REQUIREMENTS FROM PUBLIC SERVICE'S TWO PRIOR GAS RATE CASES THAT ARE APPLICABLE TO THIS PROCEEDING.

A. The following requirements were ordered through decisions entered in Public Service's 2012 and 2015 Gas Rate Cases:

- 2012 Gas Rate Case (Proceeding No. 12AL-1268G)
  - In a future FTY filing, Public Service is to provide the HTY, including all *pro forma* adjustments; a line-by-line comparison with an historical test year with adequate explanations for all deviations; and ten years' worth of data to validate forecasts.[6]
- 2015 Gas Rate Case (Proceeding No. 15AL-0135G)
  - Public Service may defer and establish a regulatory asset for additional costs of the Enhanced Emergency Response Program in 2016 and 2017, with a requirement for tracking and meeting certain metrics, including an average response time of 60 minutes or less.[7]
  - With respect to the Damage Prevention Program, Public Service will place costs that differ from the level approved in base rates into a regulatory asset to be deferred until the next rate case. Public Service will also work with Staff to establish 2014 costs against which the deferral will be measured.[8]
  - Public Service is to place capital costs associated with replacing the General Ledger and Work Asset Management systems in a regulatory asset to be deferred to the next gas rate case.[9]
  - Public Service is to establish a regulatory asset for cost recovery of property taxes which will be in place until the next gas rate case,

[6] Decision No. R13-1307, Ordering ¶10.
[7] Decision No. R15-1204, ¶¶204 and 206 and Ordering ¶30.
[8] Decision No. R15-1204, ¶210.
[9] Decision No. R15-1204, ¶220 and Ordering ¶34.

and implement a property tax tracker consistent with the adoption of the 2014 test year.[10]

- o Public Service is not barred from future cost recovery of Supervisory Control and Data Acquisition ("SCADA") project costs incurred in the ordinary course of business, but must conduct a thorough quantitative cost benefit analysis for project justification for future cost recovery of additional upgrades.[11]

Q. HAS THE COMPANY COMPLIED WITH ALL OF THESE REQUIREMENTS?

A. Yes. Table SBB-D- 11 captures the compliance items listed above and the witnesses or witnesses addressing each compliance item.

Table SBB-D- 11

Requirement	**2017 PSCo Case**
Provide HTY with pro forma adjustments	Attachment SPB-4 attached to Steve Berman's Direct Testimony
a line-by-line comparison with an historical test year with adequate explanations for deviations	Line by line comparison can be found in Attachment SPB-5 & 6 attached to Steve Berman's Direct Testimony. Explanations for deviations provided by appropriate witnesses.
ten years' worth of data to validate forecasts	Ten Year detail of Per Book Operating and Maintenance expenses, Attachment SPB-10 attached to Steve Berman's Direct Testimony Ten Years of Capital Expenditures - Attachment SBB- 9 and Ten Years of Customer Numbers and Use - Attachment SBB-10, attached to Scott Brockett's Direct Testimony

[10] Decision No. R15-1204, ¶¶235 and 237 and Ordering ¶¶39 and 40.
[11] Decision No. C16-0123, ¶¶87 and 88.

Requirement	**2017 PSCo Case**
Enhanced Emergency Response - Metric tracking and an average response time of 60 min or less	Direct Testimony of Luke A. Litteken
Damage Prevention Program - Public Service will place costs that differ from the level approved in base rates into a regulatory asset to be deferred until the next rate case. Public Service will also work with Staff to establish 2014 costs against which the deferral will be measured	Direct Testimony of Luke A. Litteken
GL & WAM - capital costs associated with replacing the General Ledger and Work Asset Management systems in a regulatory asset to be deferred to the next gas rate case	Direct Testimony of Timothy Brossart Direct Testimony of Steven Berman
Property Taxes - establish a regulatory asset for cost recovery of property taxes which will be in place until the next gas rate case, and implement a property tax, tracker consistent with the adoption of the 2014 test year	Direct Testimony of Steven Berman and Direct Testimony of Paul Simon
SCADA - Public Service but must conduct a thorough quantitative cost benefit analysis for project justification for future cost recovery of additional upgrades	Direct Testimony of Luke A. Litteken

XIV. REQUESTED APPROVALS

Q. PLEASE STATE THE APPROVALS THAT THE COMPANY SEEKS FROM THE COMMISSION IN THIS PROCEEDING?

A. The Company's requests are itemized below:

- The Company's requests approval of the proposed MYP for the gas department. The requested GRSAs under this MYP are 33.64 percent in 2018 (with an implementation date on or around February 1, 2018), 65.93 percent as of January 1, 2019, and 76.46 percent as of January 1, 2020.
- The Company seeks authority to defer during the MYP period (for recovery in future rates) any pension expenses, property tax expenses, or Damage Prevention program expenses above or below the base levels of such expenses approved for recovery during the MYP period.
- The Company requests approval to defer any costs stemming from the new PHMSA rules that may be promulgated, as Ms. Campbell discusses. Since the potential scope and impact of these new PMHSA rules are still subject to considerable uncertainty, the Company includes no such expenses in our proposed rates during the MYP period. Instead, the Company seeks approval to defer any such costs during the MYP period, if and when they are actually incurred, for future recovery.
- The Company requests approval of the updated depreciation rates provided in Attachments MLO-7 & MLO-8 of the Direct Testimony of Melissa L. Ostrom.
- The Company seeks approval of the Earnings Sharing Test and related sharing bands, as explained earlier in my Direct Testimony.

- The Company seeks approval of the adjustments for material changes to expenses during the term of the MYP provided, as Attachment SBB-2.
- The Company seeks authority to extend the existing QSP for the gas department through 2020.
- The Company seeks approval of the proposed updates to our Charges for Rendering Service.
- The Company seeks approval to eliminate the summation sheets.
- The tariffs provided in Attachment SBB-8 include all additions, removals or modifications required for the approvals summarized above. Accordingly, the Company also requests approval of these tariffs.

XV. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN THIS PROCEEDING.

A. In this Phase I filing the Company is requesting a better path for the gas department and our customers. We have proposed a MYP that builds upon the experiences of the electric department and incorporates the fundamental elements of MYPs used successfully in other jurisdictions in the U.S. Our filing addresses key policy issues, and offers more long-term benefits and solutions than the typical Phase I filing based on a single test year. The Company has invested significantly in its gas utility operations to deliver on its commitment to pipeline safety and reliability. The gas department has not earned its allowed ROE since 2009, despite filing three separate requests for rate relief. Business conditions are not what they were a decade ago. The economy in Colorado is growing, as is the number of customers we serve, which adds costs to our business. Customers like natural gas, but they are using less (declining use per customer). Revenue growth is not adequate to fund the planned investments that our customers want. No one wants annual rate cases. It is time for change. The proposed MYP provides a fresh approach that deserves serious consideration.

The Company is providing expanded testimony, including testimony of a nationally recognized expert, in this proceeding to support the adoption of a MYP. We have designed this plan to offer many benefits over the next several years and beyond, and have demonstrated that the prices we propose will offer great value for the service our customers receive – based on the metrics that really matter to customers. PEG's benchmarking studies demonstrate this point, as do our national price rankings and bill history.

The primary advantages of the Company's proposed MYP are:

- rate certainty for customers,
- incentives to drive continuous process improvement or cost efficiency with customer protections,
- reduced regulatory costs,
- insight and transparency into our long-term planning,
- increased emphasis on important bottom-line metrics rather than line-by-line reviews,
- a fairer opportunity for the Company to earn its authorized ROE, and
- the facilitation of more gradual price increases or rate smoothing during the MYP without burdening future customers with past costs.

MYPs are not new to regulatory bodies, and many economic regulators have concluded that they are in the public interest. The Colorado Commission itself has approved two MYPs for the Company's electric department. The Company's proposed MYP does rely on forecasts and indices. Most businesses, governmental agencies and even individual households use forecasts for business and financial planning. The consensus appears to be that projections, while imperfect, provide better insight into future conditions than assuming history will repeat itself.

The Company respectfully requests that the Commission find the proposed MYP to be in the public interest based on its compelling benefits.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Scott B. Brockett

I graduated from Otterbein College in 1980 with a Bachelor of Arts degree in English and Economics. I graduated from Miami University (Ohio) in 1981 with a Masters of Arts degree in Economics.

From August 1982 through February 1999 I was employed by the Minnesota Department of Public Service ("Department"), a state agency charged with developing energy policy and representing all customers in utility matters before the Minnesota Public Utilities Commission.

From August 1982 through May 1984 I was an analyst in the Computational Services Unit, where conducted economic analyses and reviewed telecommunications depreciation filings. From June 1984 through January 1991 I worked in the Energy Unit. My major areas of responsibility were buyback rates for Qualifying Facilities, rate design, embedded cost of service and marginal cost of service.

From January 1991 to August 1994 I held two similar supervisory positions. My primary responsibility was to oversee the Department Staff's advocacy in electric utility matters including general rate proceedings, integrated resource plans, demand-side management programs, and a wide variety of other regulatory issues.

In August 1994 I was promoted to Manager of Energy Planning and Advocacy. In this capacity the responsibilities I assumed as a supervisor were expanded to include natural gas advocacy, the development of state energy policy, and testifying on energy matters before the Minnesota Legislature. In December 1998 I was appointed Acting Assistant Commissioner of Energy. I held this position until February 1999.

From February 1999 to July 2004 I was employed by Consumers Energy ("Consumers"), an investor-owned utility providing natural-gas and electric service in Michigan, as Supervisor of Pricing and Revenue Forecasting. My primary responsibilities were developing prices for Consumers' electric and natural gas services, conducting economic analyses of various service options, evaluating the impact of Michigan's electric open-access program, estimating customer bills, and forecasting natural gas and electric revenue. I also managed Consumers' voluntary Green Power Pilot Program.

During my tenure with the Department I testified on demand-side management, rate design, embedded cost of service, marginal cost of service, and the environmental costs of electric generation. During my tenure with Consumers I testified on gas pricing issues and electric stranded costs.

I joined Xcel Energy as Manager, Gas Pricing and Planning, in July 2004. I assumed my current position in 2008. During my tenure with Xcel Energy I have testified on pricing issues in many general rate cases (Proceeding Nos. 05S-264G, 06S-656G, 08S-146G, 09AL-299E, 10AL-963G, 11AL-947E, 12AL-1268G, 12AL-1269ST, 14AL-0660E and 16AL-0048E). I have also testified on policy and technical issues in proceedings involving electric interruptible rates, Demand Side Management cost recovery and incentives, cost recovery issues involving the implementation of the Clean

Air - Clean Jobs Act, the acquisition of various generating units, distributed generation, and revenue decoupling.

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

AFFIDAVIT OF SCOTT B. BROCKETT
PUBLIC SERVICE COMPANY OF COLORADO

I, Scott B. Brockett, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the 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 Denver, Colorado, this first day of June 2017.

Director, Regulatory Administration

Subscribed and sworn to before me this 1st day of June, 2017.

Jennifer D. Augustine
Notary Public

JENNIFER D. AUGUSTINE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20064006595
MY COMMISSION EXPIRES 02/16/2018

My Commission expires 2/16/18