Columbia Gas of Pennsylvania, Inc.
2015 General Rate Case
Docket No. R-2015-2468056
Standard Filing Requirements
Testimony - All
Volume 10 of 10

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MARK R. KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Table of Contents

I. INTRODUCTION 1

II. CASE OBJECTIVES 5
- a. Proposed Rate Increase 6
- b. Pipeline Safety Enhancements 13
- c. Other Objectives 14

III. REVENUE REQUIREMENT 16

IV. MANAGEMENT EFFECTIVENESS 17
- a. Call Center Performance 20
- b. Residential and Small Commercial Billing Data 21
- c. Meter Reading 21
- d. Dispute Reporting 22
- e. Customer Satisfaction 22

V. INTRODUCTION OF WITNESSES 28

I. INTRODUCTION

Q. Please state your name and business address.

A. Mark R. Kempic, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as its President.

Q. What are your responsibilities as Columbia's President?

A. I am the corporate officer responsible for the leadership of Columbia and its various departments, including Rates and Regulatory Policy, Governmental Affairs, Communications and Community Relations.

Q. What is your educational and professional background?

A. I hold an Associate Engineering Degree in Solar Heating and Cooling Technology from the Pennsylvania State University, a Bachelor's of Science Degree in Computer Science from the University of Pittsburgh and a Juris Doctor from the Capital University Law School in Columbus, Ohio. I held various positions within Columbia and its parent company from 1979 through 1992 including emergency service dispatcher, engineering technician, information systems analyst, gas supply and corporate planning analyst. From 1992 through 1994, I worked at a law firm where I represented the interests of industrial customers in utility regulatory proceedings before the Public Utilities Commission of Ohio and from 1994 until my

return to Columbia, I worked as in-house state regulatory counsel for an electric company in Cleveland, Ohio. After rejoining Columbia in 1998 I initially served as an attorney, and was subsequently promoted to senior attorney and then assistant general counsel. In October of 2009, I was named Director of Rates and Regulatory Policy for Columbia. I assumed my current responsibilities when I was named President in June 2012.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I have testified before both the Pennsylvania Public Utility Commission ("Commission") as well as the Maryland Public Service Commission. Most recently, I testified in Columbia's last four base rate cases before the Commission at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, and R-2014-2406274.

Q. Please describe the scope of your testimony in this proceeding.

A. Through my testimony, I will provide the Commission with an overview of this base rate filing, discuss the objectives that Columbia seeks to accomplish in this proceeding and discuss the Company's progress since the last rate proceeding. I will also address Columbia's quality of service in compliance with Section 523 of the Public Utility Code, and I will introduce Columbia's other witnesses who provide detailed testimony and supporting documentation for all revenues, expenses and rate base elements included in the fully forecasted rate year in this base rate filing.

Q. Please describe briefly the corporate history of Columbia and its relationship with its parent company, NiSource Inc. ("NiSource").

A. Columbia was incorporated on June 23, 1960 as a wholly-owned subsidiary of the Columbia Gas System, Inc., under the Act of May 29, 1885, P.L. 29 of the Commonwealth of Pennsylvania and commenced service as Columbia Gas of Pennsylvania, Inc., on January 1, 1962, when it acquired the Pennsylvania retail business of The Manufacturers Light and Heat Company, which was at that time another wholly-owned subsidiary of The Columbia Gas System, Inc. In 1998, the Columbia Gas System, Inc. became the Columbia Energy Group ("CEG"). In turn, CEG merged with NiSource in 2000, at which time Columbia became one of ten (10) natural gas distribution companies in the NiSource corporate family. Columbia is engaged in the business of furnishing natural gas service to approximately 419,000 residential, commercial, and industrial customers pursuant to certificates of public convenience and necessity issued by the Commission. Columbia has its principal office in Canonsburg, Pennsylvania and provides natural gas distribution service in portions of 26 counties in Pennsylvania, primarily in the western half of the state, as well as parts of Northwest, Southern and Central Pennsylvania.

NiSource, headquartered in Merrillville, Indiana, is an energy holding company whose subsidiaries provide natural gas, electricity and other products and services to approximately 3.8 million customers located within a corridor that runs from the Gulf Coast through the Midwest to New England. NiSource is the successor to an

Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition of CEG on November 1, 2000, NiSource became a Delaware corporation registered under the Public Utility Holding Company Act of 1935 (now known as the Public Utility Holding Company Act of 2005). NiSource is also subject to the jurisdiction of the Securities and Exchange Commission and is traded on the New York Stock Exchange with the symbol "NI". The NiSource core operating companies engage in natural gas transmission, storage and distribution, as well as electric generation, transmission and distribution. NiSource's natural gas distribution operations serve at retail over 3.4 million residential, commercial and industrial customers with approximately 58,000 miles of pipeline in seven states (Indiana, Kentucky, Maryland, Massachusetts, Ohio, Pennsylvania, and Virginia). The NiSource gas distribution companies are: Bay State Gas Company dba Columbia Gas of Massachusetts, Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

Q. Could you please describe the separation announced by Columbia's parent company NiSource?

A. On September 28, 2014, NiSource announced that its Board of Directors approved, in principle, plans to separate its natural gas pipeline and related businesses into a stand-alone, publicly traded company, Columbia Pipeline Group ("CPG"). The

separation remains on schedule to take place on July 1, 2015, with a preliminary Form 10 for CPG filed with the U.S. Securities & Exchange Commission on February 6, 2015. Key expected board members and executive team members for both companies were announced in late 2014 and early 2015. NiSource also entered into two $1.5 billion revolving credit facilities in December 2014 to support the liquidity needs of both NiSource and CPG following the separation. Both facilities will become effective at the time of the separation. The post-separation NiSource facility will amend and replace the company's existing $2.0 billion revolving credit agreement.

Q. How does the separation impact this rate case?

A. The transition does not impact Columbia's cost of service in this rate case. All costs directly related to the transition incurred to date have been recorded on the books of NiSource Inc. No portion of the expenses has been allocated to Columbia.

II. CASE OBJECTIVES

Q. Please summarize Columbia's major objectives in this proceeding.

A. First, Columbia seeks Commission approval to increase its base rates to recover the revenue requirement associated with the capital Columbia has invested, and will continue to invest, in its facilities as part of its accelerated pipeline replacement program. Second, Columbia seeks to recover the revenue requirement associated with its increased focus on training and pipeline safety standards, which is

increasing Columbia's operating and maintenance costs. Approval of these objectives is necessary for Columbia to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers while providing the Company with a reasonable opportunity to recover its costs and to earn a fair rate of return. Further, approval of these objectives will demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings. My testimony will outline, at a high level, the objectives of Columbia's filing. Details and documentation supporting each of the objectives will be provided by Company witnesses that I will introduce later in my testimony.

a. <u>Proposed Rate Increase</u>

Q. Will you please explain Columbia's first objective?

A. Columbia first seeks recovery of, and an opportunity to earn a return on, the capital investments being made in its distribution system which are necessary to provide safe and reliable natural gas distribution service to its customers. In light of substantial capital investment Columbia has made since its last rate case, the large capital investments that will be made through the end of 2016, and the increasing operating and maintenance ("O&M") costs associated with increasing training and standards related to pipeline safety procedures, Columbia is filing this base rate case using the fully projected future rate year contemplated by 66 Pa. C.S.A. § 315

("Act 11") in order to provide itself with a reasonable opportunity to recover its investment in its distribution system and its O&M expenditures.

Q. Why is Columbia filing a base rate case instead of using the Distribution System Improvement Charge ("DSIC")?

A. As I stated, Columbia's revenue deficiency is driven by both the large capital investment that it continues to make in modernizing its distribution system as well as increases in O&M expenditures over and above the level built into current rates which will enable Columbia to implement its training and pipeline safety initiatives. Due to the scale of Columbia's investments in replacement pipe and training and pipeline safety standards, Columbia's requested overall distribution (i.e. exclusive of gas costs) revenue increase in this case is approximately 16%, which exceeds the current 5% cap on DSIC surcharges. In addition, the DSIC does not permit recovery of O&M costs. Thus, even if the 5% cap were increased, a rate case would be needed to recover the increases in O&M costs. This is not to say that Columbia will never use the DSIC. When Columbia's O&M costs do not make up a material portion of the revenue deficiency and when rate base grows to a point where the DSIC will provide adequate revenue to support the scale of Columbia's pipeline replacement program, Columbia anticipates that it will be able to use the DSIC instead of base rate proceedings.

Q. What is Columbia's proposed rate increase in the case and what are some of the primary drivers for the increase?

A. Based on the rates established in Columbia's last rate case and Columbia's existing and planned capital and O&M programs, Columbia will experience a revenue deficiency of approximately $46 million as detailed and supported in testimony of Company witness Miller (Columbia Statement No. 4). This revenue deficiency is driven by two primary factors. First, Columbia has made, and continues to make, substantial capital investments in its system. As detailed in Company witness Davidson's testimony (Columbia Statement No. 15), since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced 3,416,498 feet (over 647 miles) of cast iron and bare steel pipe. In 2014 alone, Columbia replaced over 78 miles of cast iron and bare steel pipe. To put these numbers into context, as shown in Figures 1 and 2 below (based on information publicly available from the 2013 DOT reports), Columbia exceeded both the capital investment as well as the number of miles of pipe replaced by the other gas utilities in the Commonwealth. While this information is not intended to put Columbia in competition with the other gas utilities, it is provided to explain why Columbia is once again filing a base rate case when other gas utilities have not.

Figure 1

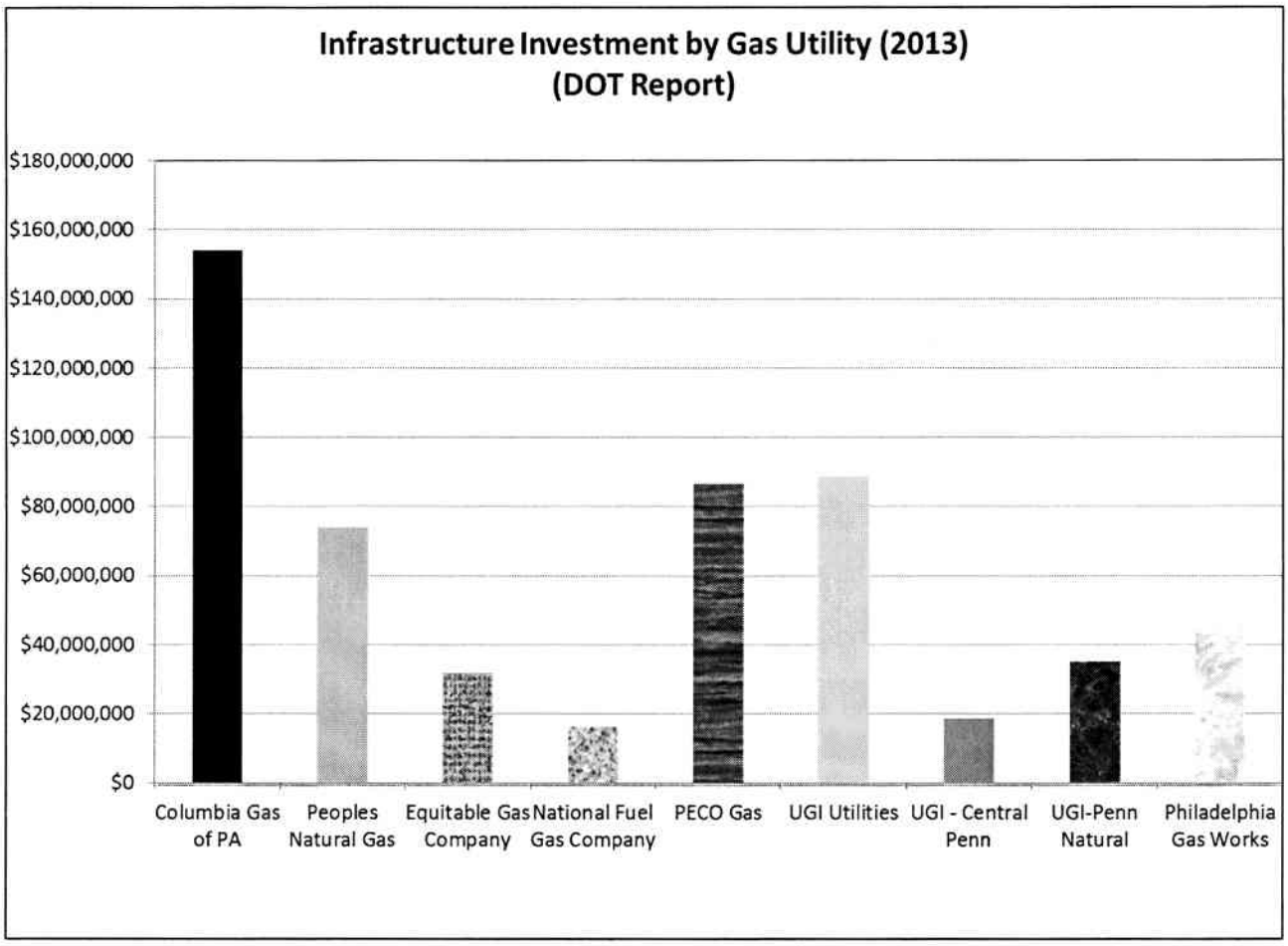
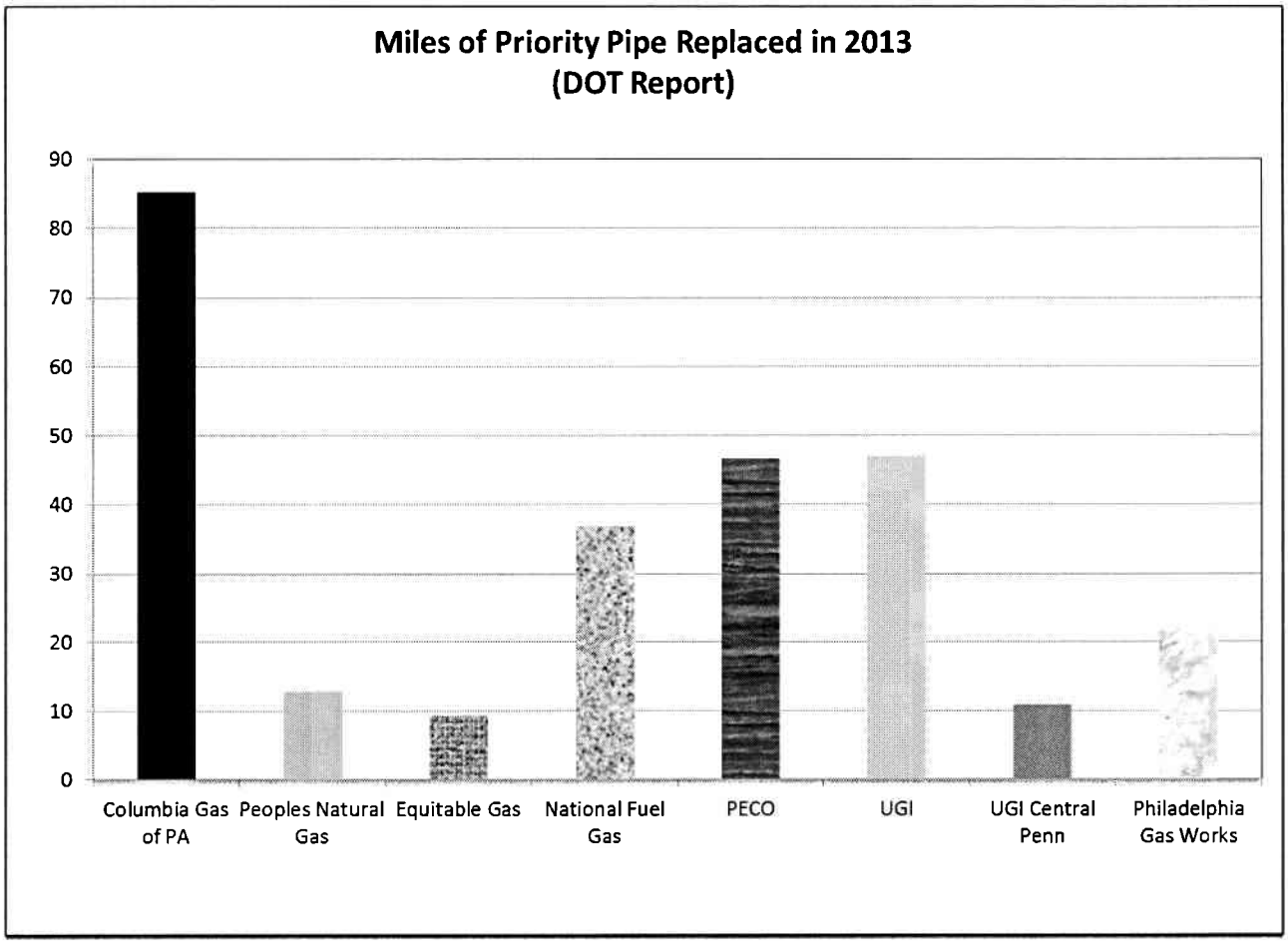

Infrastructure Investment by Gas Utility (2013)
(DOT Report)
$180,000,000
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
Columbia Gas of PA
Peoples Natural Gas
Equitable Gas Company
National Fuel Gas Company
PECO Gas
UGI Utilities
UGI - Central Penn
UGI-Penn Natural
Philadelphia Gas Works

Figure 2



In addition to Columbia's past investments, Columbia intends to maintain the pace of its capital replacement program into the future. In Columbia's 2014 Rate Case, at Docket No. R-2014-2406274, Columbia forecasted that its 2014 and 2015 capital budgets for the replacement of cast iron and bare steel would be $145 million and $104 million, respectively. In reality, Columbia's 2014 actual investment for replacement pipe was $148.3 million and its age and condition capital budget for 2015 is $144.6 million. In addition, as detailed in the Company's response to GAS-

ROR-014, the Company intends to increase its capital investment after 2016 and to continue to invest at an aggressive level through 2019. I must note that Columbia's ability to increase its capital investment and maintain these unprecedented levels of investment is a result of Act 11's impact on reducing the regulatory lag that was previously associated with utility investment in Pennsylvania prior to the passage of Act 11.

Q. Why does Columbia want to increase its capital investment beyond current levels?

A. As shown in Figure 3 below, Columbia's distribution system contains more pipe than the other gas utilities in Pennsylvania.

Figure 3

NGDC	Miles of Pipe (2013)
Columbia Gas	7,410.9
PGW	3,024.0
PECO	6,761.0
UGI	5,486.6
UGI Central Penn	3,715.7
UGI Penn Natural Gas	2,522.2
Peoples Natural Gas	6,786.3
Equitable	3,523.3
National Fuel	4,826.5
Peoples TWP	2,624.0

The size of the Company's capital program is driven by the amount of pipe that needs to be maintained and ultimately replaced. However, this is not the sole reason for Columbia's proposal to increase its capital investment.

Q. Please explain.

A. Despite having more pipe than any other gas utility in Pennsylvania, Columbia has one of the lowest average numbers of customers per mile. The Company has approximately 56 customers per mile, which is substantially less than the average customer per mile for gas utilities located in more urban areas (i.e., PGW and PECO have approximately 169 and 74 customers per mile respectfully). Due to the large amount of pipe and the relative low number of customers per mile, the Company seeks to take advantage of the current low price of gas in Pennsylvania. That is, by increasing its investment in pipeline replacement now, while gas prices are low, Columbia seeks to replace as much pipe as possible in order to ameliorate the impact on customer's total bill. Indeed, Columbia has calculated that, even after the entire increase requested in this proceeding is added to an average customer's bill, after adjusting for inflation, the average customer will be paying a total bill in 2016 that is about 17 percent less than they were paying in 2006, which is immediately before the time that Columbia began its accelerated pipeline replacement program. Stated another way, since all of the bare steel and cast iron pipe needs to be replaced at some point, the ideal time to make this investment is now during a time of low gas costs so the impact to customers is minimized. Although gas prices may increase in the future, by increasing its capital investment now, while gas prices are low, the Company is attempting to reduce the need to increase capital spend during periods when gas prices are high.

b. Pipeline Safety Enhancements

Q. What is Columbia's second objective in this case?

A. In addition to the capital costs associated with Columbia's accelerated pipeline replacement effort, Columbia will be incurring increasing O&M costs. As explained in the Exhibits sponsored by Company witness Miller, Columbia's total O&M costs will increase from $168.5 million during the historic test year to $177.7 million during the fully forecasted rate year (Exhibit 104, Schedule 1, Page 4). These O&M increases are primarily driven by the enhanced training and pipeline safety efforts that Columbia continues to take on its system. As described in detail in Company witness Davidson's testimony, there are multiple Federal Pipeline Safety Rules and Advisories that continue to change the manner in which Columbia operates and require additional employees, employee training and new operating standards. As shown on Exhibit 104, Schedule 1, Page 4, major drivers of the O&M increases are Columbia's labor and the "NCSC – Shared NGD Operations" category, which includes costs associated with NiSource Corporate Services Company ("NCSC") services provided to Columbia such as Engineering, Pipeline Safety & Compliance, Technical Training, Rates and Regulatory Support, Call Center, etc. Therefore, Columbia's second objective in this case is to secure the revenue necessary to cover the incremental costs of the new employees, the costs associated with developing and implementing training programs and the costs associated with implementing

the pipeline safety enhancements explained in Company witness Davidson's testimony.

c. <u>Other Objectives</u>

Q. Does Columbia have any other objectives in this proceeding?

A. Yes, Columbia is seeking several tariff changes to make it easier for customers to obtain gas service. While Columbia recently received approval to implement its New Area Service Rider which permits customers to spread a line extension deposit over 20 years instead of paying it up front as had been the convention, the fact remains that even under the New Area Service Rider, customers need to pay a deposit to obtain natural gas service. As explained in Columbia witness Waruszewski's testimony, Columbia seeks approval to change its tariff so that it can provide an allowance of up to 150 feet of main line extension to prospective customers without requiring a deposit.

Q. Does Columbia believe the New Area Service Rider is ineffective?

A. No, just the contrary. Columbia designed the New Area Service Rider to produce a significant increase in its new line extensions. Based on Columbia's experience before having the New Area Service Rider in place, Columbia received an average of just over $300,000 in customer deposits each year. Columbia designed the New Area Service Rider with a $1,000,000 cap on customer deposits that could flow through the New Area Service Rider, thereby supporting a 300% increase in the number of line extensions. Columbia expects this to translate into a total increase

of $4 or $5 million in capital invested in new business construction. Since Columbia implemented the New Area Service Rider late in 2014, it has secured three New Area Service contracts accounting for 70 new customers. Based on discussions with the customers, 68 of the new customers would have been lost to propane if not but for the availability of the New Area Service Rider. In addition, the Company is working with other potential customers regarding their interest in the program and providing them with the information necessary to evaluate their options.

Q. If the New Service Area Rider is effective, why does Columbia seek approval for additional tariff changes?

A. As explained in the testimony of Company witness Waruszewski, certain parties in Columbia's New Area Service Rider proceeding, along with Commissioner Witmer, supported additional options for expanding natural gas service to underserved markets. The Company's proposal to provide a 150 foot extension without requiring a customer deposit will encourage expansion of the system. Adding nearby loads to Columbia's system provides the most benefit to the existing customer base given that the costs to extend facilities will be less due to the close proximity. Providing these nearby potential customers with the opportunity to receive a 150 foot extension without paying a deposit will also help focus the New Area Service Rider on more remote potential customers.

III. REVENUE REQUIREMENT

Q. How did Columbia determine the revenue requirement for this case?

A. As described in the testimony of Company witness Miller (Columbia Statement No. 4), Columbia reviewed its costs to serve its customers using a fully forecasted rate year ending December 31, 2016, pro forma and adjusted for known and measurable changes. Columbia then compared the costs determined for the fully forecasted rate year to the revenues at present rates calculated for the fully forecasted rate year. This analysis produced a revenue deficiency, from which Columbia calculated the corresponding revenue requirement that Columbia will require to make up this deficiency with a fair rate of return on the investment devoted to serving the public.

Q. Why is the proposed rate increase necessary to eliminate the revenue deficiency?

A. Columbia's current rates do not provide the opportunity for the Company to recover its costs to serve its customers, including a fair rate of return on the capital invested to provide distribution service to the public. The proposed rates have been developed to eliminate this deficiency and Company witness Moul (Columbia statement No. 8) will support Columbia's rate of return in his testimony.

Q. Without the increase requested in this case, what will Columbia's rate of return be?

A. Without the increase requested, Columbia's overall rate of return will drop to 6.06% in the Fully Forecasted Rate year as shown on Exhibit 102, Schedule 3, Page 3.

Q. What overall rate of return and return on equity does Columbia propose in this case?

A. Columbia proposes an overall rate of return of 8.14%. Columbia witness Moul demonstrates that Columbia should be granted an opportunity to earn a 10.95% rate of return on common equity.

IV. MANAGEMENT EFFECTIVENESS

Q. What evidence supports adjusting the Company's requested rate of return for management effectiveness?

A. In addition to Columbia's aggressive pipeline replacement program and pipeline safety enhancements detailed in the testimony of Columbia witness Davidson, which demonstrate the effectiveness of Columbia's management and its concern for excellence in customer service, I have obtained the most recent Management Performance Audit reports from the Commission's website for Columbia, Peoples Gas Company Philadelphia Gas Works, UGI, National Fuel Gas, Equitable Gas and PECO and analyzed them. The data appears as Exhibit MRK-1, which is attached to my testimony. Initially, I would observe that the Commission's auditors employ a ranking category system that ranges from "Meets Expected Performance" to "Major Improvement Necessary" and they assign one of those ranking categories to various aspects of a utility company's management performance. I have evaluated the number of rankings categories for each gas distribution company mentioned and

determined the number of times the Commission's auditors assigned each of the various ranking categories to a gas distribution company.

Figure 4

Standard	CPA	Peoples	PGW	UGI	NFG	Equitable	PECO
Meets Expected Performance	50%	11%	0%	8%	13%	7%	20%
Minor Improvement Necessary	25%	44%	43%	42%	75%	47%	47%
Moderate Improvement Necessary	25%	22%	43%	33%	13%	33%	33%
Significant Improvement Necessary	0%	22%	14%	17%	0%	7%	0%
Major Improvement Necessary	0%	0%	0%	0%	0%	7%	0%
Total	100%	100%	100%	100%	100%	100%	100%

As Figure 4 illustrates, Columbia achieved the "Meets Expected Performance" ranking category in 50% of the categories evaluated by the auditors, more than twice as often as any of Columbia's peers. Also, Columbia was one of only three gas companies that did not receive any ranking of "Significant Improvement Necessary". A review of the information in Figure 4 and Exhibit MRK-1 shows that, based on the Commission's own auditors, Columbia's performance exceeds that of its peers. Based on the totality of the evidence, the Commission should grant an increased return on equity based on Columbia's superior performance.

Q. Please provide evidence concerning the performance of Columbia's management in providing quality service to its customers.

A. Recently, the Commission released its Annual Utility Consumer Activities Report and Evaluation (UCARE) for 2013. Based on the overall information contained in the report, which describes how well utilities handle consumer complaints, Columbia's performance was excellent. During 2013, Columbia's overall performance in handling Consumer Complaints was better than any gas or electric

utility. Columbia's Complaint rate per 1,000 residential customers was .47 in 2013; only NFG had a lower rate of .46. However, in the second component of this measure-- Justified Consumer Complaints, Columbia's justified rate per 1,000 residential customers was .03, while NFG's was .08. None of the other electric or gas utilities had better aggregate rates than Columbia in any of these two measures during 2013.

In reviewing Company negotiated Payment Arrangement Requests (PARs) that are evaluated by the Commission, Columbia's PAR Complaint Rate per 1,000 Residential Customers was 2.68 in 2013, only Peoples Gas had a lower rate of 1.85. However, Columbia had the best Justified Payment Arrangement Request Rate of .02. None of the electric or gas utilities had a better rate than Columbia did in either of these combined measures in 2013. A low consumer complaint rate and justified rate are excellent indicators of Columbia's ability to work together with its customers to resolve matters reasonably. The last component of the Commission's UCARE report focuses on Compliance with Commission Regulations. In 2013, Columbia had an infraction rate of .01 per 1,000 residential customers. This infraction rate was better than any electric or gas utility during 2013. Looking at all three measures of this report: Consumer Complaints, Payment Arrangement Requests and Compliance, Columbia exceeded the performance of the other utilities in handling consumer issues in 2013.

Q. Can you provide an overview of Columbia's 2014 Quality of Service Performance Report?

A. Yes, the "Quality of Service Performance Report" is organized in five general categories: Call Center Performance, Residential and Small Commercial Billing, Meter Reading, Dispute Reporting, and Customer Satisfaction. Columbia's performance for each of these categories is explained below.

a. Call Center Performance:

Despite the extreme and prolonged cold weather during the 2013/2014 winter heating season, Columbia's call center metrics remained fairly consistent with 2013's results. Although Columbia experienced a decrease in calls answered within 30 seconds, from 79% (2013) to 77% (2014), the call volume during 2014 was 11% more than during 2013, which accounts for the slight drop in calls answered in 30 seconds. Recognizing the impact that this could have had on the payment of residential customer bills, Columbia's management made the decision to delay collection activity during the first two weeks of April 2014 to afford customers the opportunity to negotiate a payment arrangement to maintain gas service. Columbia's busy-out rate of 0% was consistent with prior year's performance. Considering the 11% spike in the volume of customer calls, the abandonment rate barely increased from 2.23% to 2.33%.

To enhance customer satisfaction with the Interactive Voice Recognition ("IVR") phone system, Columbia implemented a change in 2014 that enables customers to opt out of the automated system sooner and speak directly to a live customer service representative. This change has resulted in Columbia receiving higher customer satisfaction marks from its customers.

b. Residential and Small Commercial Billing Data:

For the fourth consecutive year Columbia did not have any deferred billings for its residential or small commercial customers during 2014. In 2014, Columbia initiated a new program to assist with the investigation of billing abnormalities. Thus far, this program has been successful in reducing the number of service orders sent to the Company's field technicians to investigate billing consumption fluctuations, thereby increasing customer satisfaction and reducing costs to customers.

c. Meter Reading:

Columbia's meter reading performance in 2014 was consistent with 2013's results which were already very good. Since Columbia added Automated Meter Reading ("AMR") devices to all meters which enables the readings to be performed by driving a car down the street to capture a signal versus physically walking to each meter to visually read it, Columbia has been both successful at reducing the number of meter reading routes in its service territory at the same time it was able

to move to actual monthly meter readings. This has resulted in a cost savings to the Company and has improved customer satisfaction since customers did not like having estimated meter readings.

d. Dispute Reporting:

During 2014, Columbia did not have any utility dispute report responses that went beyond the 30 day threshold prescribed in Section 56.151(5).

e. Customer Satisfaction:

Q. Are there metrics that Columbia utilizes to gauge its effectiveness in providing quality customer service to its customers and satisfaction?

A. Yes, in addition to performing a thorough review and analysis of the Commission's UCARE Report, the Universal Service and Collections Report and the Quality of Service Performance Report, Columbia uses three outside contractors to perform surveys to determine the customer satisfaction rating of its customers. Those contractors are Metrix/Matrix, Thoroughbred Research, and J.D. Powers. Metrix/Matrix is the independent firm that also performs and reports data to the Commission, relative to its "Customer Transaction Survey," which is part of the Quality of Service Performance Report. Besides using these three independent parties, Columbia's call center performs a random post call survey to determine the effectiveness of its call center representatives.

Q. Can you share the results of these surveys?

A. Based on the results of the Thoroughbred Survey, Columbia has exhibited a strong history of providing quality service to its customers. As you can see in the following figures, Columbia's Call Center Representatives continually reach the 90%+ satisfaction mark in gauging Courtesy and Knowledge. The Metrix/Matrix survey also shows that Columbia's Field Service Representatives easily reach the 90%+ satisfaction mark annually in these categories.

Customer Service Representative Results:

Figure 5

Columbia Gas of Pennsylvania	2007	2008	2009	2010	2011	2012	2013	2014
Thoroughbred CSR Attributes	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average
Being Courteous and Professional	90	93	90	96	100	96	100	97
Treating as respected customer	90	93	90	96	90	95	100	96
Showing concern for situation	90	89	90	93	90	93	90	94
Displaying knowledge in job	90	93	90	95	90	95	90	95
Adequately answering questions	90	92	90	95	90	95	90	95
Understanding purpose for call	90	91	90	94	100	95	90	95
Having authority to make decision	90	87	90	92	90	91	90	92
Working quickly and efficiently	90	89	90	93	90	93	90	93
* Source document = Thoroughbred Survey website/Columbia Gas of PA/Monthly Flash Report								

Field Representative Results:

Figure 6

2014	Columbia Gas Percent Satisfaction
Rep Handling Request	93.0
Timely Completion	84.0
Field Rep Response	86.0
Field Rep Courtesy	94.0
Field Rep Knowledge	99.0
Respect of Property	98.0
Field Rep Overall	97.0
Contact Overall	92.0

Source: Metrix/ Matrix Survey

Q. How well did Columbia perform on "First Call Resolution" in 2014 with its Customers?

A. The chart in Exhibit MRK-2, attached to my testimony, reflects first call resolution data for the past five years. Over the last five years, Columbia improved its first call resolution from 71% to 79%. This vital statistic confirms Columbia's success in satisfying its customers the first time they contact the company.

Q. How did Columbia perform in the 2014 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia was ranked first in Customer Satisfaction among all midsize utilities in the east region. As well, Columbia was recognized as being 1 of the top 10 most improved utilities nationally in 2014. The J.D. Power survey is yet another indicator of Columbia's focus on meeting and exceeding customer expectations.

Q. What has been Columbia's success with implementing Chapter 14 Regulations?

A. Since deploying these collection tools at the beginning of 2005, Columbia has been successful in lowering its residential write-offs of uncollectible accounts. Indeed, based upon annual data filed with the Commission pursuant to Section 56.231 of the Public Utility Code, since 2004, Columbia has reduced its gross residential write-off ratio from 4.81% to 2.0% in 2013, and its net residential write-off ratio from 3.48% in 2004, to 1.34% in 2013 as show in Figure 7 below:

Figure 7

Year	Gross Residential Revenues	(1) Gross Residential Write-Offs	(1) Gross Res. Write-Offs Ratio	Residential Recoveries	(1) Net Residential Write-Offs	(1) Net Res. Write-Offs Ratio
2004	$ 334,443,294	$ 16,079,652	4.81%	$ 4,453,039	$ 11,626,613	3.48%
2005	$ 422,316,022	$ 17,178,358	4.07%	$ 5,406,680	$ 11,771,678	2.79%
2006	$ 418,132,074	$ 12,725,454	3.04%	$ 3,878,311	$ 8,847,143	2.12%
2007	$ 402,803,625	$ 10,505,925	2.61%	$ 3,960,158	$ 6,545,767	1.63%
2008	$ 481,827,700	$ 10,874,843	2.26%	$ 3,613,578	$ 7,261,265	1.51%
2009	$ 387,454,010	$ 12,039,187	3.11%	$ 5,097,312	$ 6,941,875	1.79%
2010	$ 359,493,889	$ 8,162,827	2.27%	$ 3,454,140	$ 4,708,687	1.31%
2011	$ 346,316,467	$ 9,761,318	2.82%	$ 3,151,779	$ 6,609,539	1.91%
2012	$ 268,796,602	$ 7,585,766	2.82%	$ 2,765,170	$ 4,820,596	1.79%
2013	$ 329,063,560	$ 6,630,828	2.02%	$ 2,217,422	$ 4,413,406	1.34%

In the Commission's recently issued 2013 Universal Services Program and Collections Report, Columbia experienced an 18.4% reduction in its total number of customers in debt in 2013 when compared to 2012. Additionally, Columbia's total percentage of customers with overdue balances dropped to 7.85% in 2013, from 11.40% in 2012.

Q. Can you identify any data that contributes to Columbia's success in dealing with its low income customers?

A. Based on information contained in the 2013 Universal Service and Collections Report, Columbia had the most affordable CAP payment plan in the Commonwealth. In 2013, Columbia's monthly average CAP bill was $53.00. This was the lowest bill amount of all gas utilities in the industry.

Q. Can you describe any process improvements that Columbia has made to serve its customers better?

A. In 2013, Columbia implemented a new initiative to "Improve the Customer Experience." This is a company-wide review of all processes and procedures to determine which ones create value and efficiencies, and those which provide opportunities to improve customer service. In 2014 alone, Columbia deployed a number of new strategies identified by Columbia's "Improve the Customer Experience" effort with a focus on enhancing the Company's Web Self Service interface with customers. Some of these improvements include the following:

- Added a screen reader message to assist customers who are visually impaired.
- Added an option for auto pay customers to change bank information without having to cancel the existing auto payment, then having to re-enroll.
- Provided ability to schedule a payment for a future date for customers who owe only their current bill, even when the current bill due date has passed.

Previously, customers in this scenario were considered "past due" and therefore were not able to schedule a payment on a future date.

- Revised the Company's Direct E-Billing notification. A new header and graphics were added to the notification, making it easier for customers to manage their gas account.
- Added a post transactional customer satisfaction survey upon completion of a web transaction.
- Significantly decreased the length of time it takes for a customer to enroll in auto payment withdrawal, from 14 days to one day.
- Allow customers to enroll/cancel/modify in auto payment from their mobile devices.

Another interesting customer service improvement is Columbia's new "Ambassador Program". In August of 2014, Columbia introduced the "Ambassador Program" to all its employees. This program was designed to assist employees in responding to non-emergency questions or issues they receive from customers, where the employee may not have the knowledge or expertise to address the customer's concern. These inquiries are referred back to a specialized group of employees designated as "Ambassadors." The Ambassador is responsible for the follow-up of the issue and response to the customer. The timeframe for the response to the customer is 48 hours.

Also, in 2014 Columbia took steps to redesign its bill format. Customer panels were scheduled to engage and provide insight on the new bill prototype. We continue to refine the bill format based on customer input as well as potential changes resulting from the Commission's Retail Market Investigation. We anticipate the new bill will be in place sometime during 2015.

V. INTRODUCTION OF WITNESSES

Q. Please introduce Columbia's witnesses and describe their testimony.

A. Columbia presents the following witnesses:

- Columbia witness Amy Efland, the Senior Forecast Analyst for NCSC provides demand forecasting services for Columbia. In Columbia Statement No. 2, she explains how residential and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Lai's testimony (Columbia Statement No. 3) and Exhibit 3 Schedule 4. Company witness Efland also explains the projection of the future test year and fully forecasted rate year customer and load growth and comments on the residential consumption per customer.
- Company witness Chun-Yi Lai is a Lead Regulatory Analyst for NCSC. She provides support for regulatory filings for Columbia. In Columbia Statement No. 3, Company witness Lai supports the Company's requested increase in base rates by providing detailed information on the Company's pro forma operating revenues for

the historical test year and for the twelve months ending December 31, 2016 (Fully Forecasted Rate Year).

- Company witness Kelley Miller is a Lead Regulatory Analyst for NCSC and provides regulatory accounting and strategy services to Columbia. In Columbia Statement No. 4, witness Miller presents Columbia's cost of service and quantifies the revenue deficiency based on operating costs and revenues, as adjusted. Company witness Miller supports Columbia's Cost of Service O&M expenses. In addition, she provides a comparison of actual O&M expenses for the twelve months ended November 30, 2014, to the projections that were included in the Company's last base rate proceeding, R-2014-2406274.
- Company witness John J. Spanos is a Senior Vice President in the Valuation and Rate Division of Gannett Fleming, Inc. In Columbia Statement No. 5, witness Spanos, supports the depreciation study Gannet Fleming prepared for gas plant of Columbia.
- Company witness Nicole Paloney is Director of Rates and Regulatory Affairs for Columbia. In Columbia Statement No. 6, she provides detail and support about the methods and assumptions used to develop the Historic Test Year, Future Test Year and the Fully Forecasted Rate Year rate base as presented in Exhibits 8 and 108.
- Company witness Brian E. Elliott is a Manager for Regulatory Strategy and Support for NCSC. In Columbia Statement No. 7, witness Elliott presents the Allocated

Class Cost of Service Studies by rate class at present and proposed rates, and an analysis supporting minimum charges for all rate schedules.

- Company witness Paul Moul is the Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. In Columbia Statement No. 8, Company witness Moul presents detailed testimony and documentation and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Commission should recognize in the determination of the revenues that Columbia should be given an opportunity to earn as a result of this base rate case. His recommendation is supported by detailed financial data and an in-depth explanation of the application of the various financial models upon which he relies.
- Company witness Matthew T. Hanson is the Director of Financial Planning for NCSC and is responsible for the financial planning and budgeting process for the NiSource gas distribution business segment, which includes Columbia. In Columbia Statement No. 9, Company witness Hanson provides testimony in support of the budgeted O&M expenses for the Fully Forecasted Rate Year that are included in Columbia witness Miller's cost of service analysis.
- Company witness Panpilas W. Fischer is a Manager of Income Taxes at NCSC and she provides Tax Accounting services for Columbia. In Columbia Statement No. 10, Company witness Fischer supports Columbia's income tax and other tax expense included in the cost of service. She provides detail about both federal and state

income tax recovery, reduction of rate base for deferred income taxes, as well as a reduction to tax expense resulting from the Company's 2008 change in tax method of accounting for repairs.

- Company witness Mark Balmert is the Director of Regulatory Strategy & Support for NCSC which provides services and support to Columbia for its regulatory needs. In Company Statement No. 11, he testifies about Columbia's proposed revenue allocation among the various rate classes, discusses proposed customer charges, and discusses the proposed rate design that include both the proposed splitting of SGSS, SCD, SGDS and SDS volumetric charges and the merging of LGS volumetric charges with the SDS and LDS rate classes. He also testifies to the comparison of the Company's current and proposed rates.
- Company witness Nancy Krajovic is Columbia's Director of Rates and Regulatory Affairs. In Columbia Statement No. 12, she testifies about the calculation of the Rider Customer Choice adjustment ("Rider CC") and the Gas Procurement Charge ("GPC") included in this case. She also supports the Company's proposed Rider Choice Administration Charge ("Rider CAC") and discusses proposed changes to Columbia's Universal Service Programs.
- Company witness Shirley Bardes-Hasson is Manager, Regulatory Policy for Columbia and is responsible for managing regulatory activity before the Commission, including ensuring timely, accurate regulatory filings as well as monitoring regulatory cases making recommendations for Company participation

in those cases when warranted. In Columbia Statement No. 13, Company witness Bardes-Hasson explains and supports the tariff changes that the Company seeks to make in this proceeding.

- Company witness Robert C. Waruszewski is Columbia's Senior Regulatory Analyst. In Company Statement No. 14, he provides testimony concerning new proposals designed to expand the availability of natural gas service across Columbia's service territory.
- Company witness Michael Davidson is the Vice President and General Manager of Operations for Columbia. In Columbia Statement No. 15, Company witness Davidson provides an overview of Columbia's distribution system, discusses Columbia's ongoing replacement activities and provides testimony in support of Columbia's plant additions through the Fully Forecasted Future Rate Year ending December 2016. In addition, he discusses pipeline safety rules that impact pipeline safety strategy and operational execution, Columbia's historic operating performance, the strategic initiatives that the Company is undertaking to improve its overall safety and compliance efforts and the planned system enhancements to Columbia's operations. Finally, Company witness Davidson testifies regarding Columbia's DIMP, the status of the O&M activities that it has undertaken to improve its system and the additional O&M activities that it is planning to undertake.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to the two exhibits attached to this testimony, I am sponsoring Exhibit No. 13, Schedule 3 which cross references the standard filing requirements with the corresponding Exhibits and Schedules in this filing for both the historic and future test years.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance		X			
Executive Management and Organizational Structure	X				
Affiliated Interests	X				
Financial Management		X			
Customer Service			X		
Gas Operations			X		
Emergency Preparedness	X				
Human Resources	X				

D. Benefits

Where possible, the Audit Staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for the majority of recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or there was insufficient data available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or was not fully functional. Similarly, changes in work flow processes or to implement good business practices will result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

The Company will have varying ways to implement the recommendations and as a result the Audit Staff has not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted by the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through X provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

Exhibit I – 1
The Peoples Natural Gas Company
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance	X				
Executive Management		X			
Affiliated Relationships		X			
Gas Operations				X	
Emergency Preparedness			X		
Customer Service				X	
Human Resources		X			
Materials Management		X			
Diversity & EEO			X		

D. Recommendation Summary

Chapters III through XI provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of the recommendation would result in significant cost savings, major service improvements, and/or substantial improvements in management practices and performance. These recommendations should be implemented as soon as practical.

- MEDIUM PRIORITY – Implementation of the recommendation would result in important cost savings, service improvements, and/or meaningful improvements in management practices and performance. Implementation of these recommendations should begin within 12 months.

- LOW PRIORITY – Implementation of the recommendation could potentially enhance cost controls, service improvements, and/or management practices and performance. Implementation of these recommendations should begin within 18 months.

These priorities were assigned based on the Audit Staff's assessment of the potential impact of the recommendations and the Company's available resources.

however, each rating is utility specific; i.e., the rating of PGW cannot be directly compared with that of another utility.

Schumaker & Company's overall assessment of each work plan area is presented in the *Functional Evaluation Summary* shown in *Exhibit I-1* and *Exhibit I-2*, with the specific criteria used as follows:

- *Optimum* – The area is functioning more than adequately and no recommendations were made.
- *Minor improvement necessary* – The area is generally functioning adequately, but minor improvements are recommended.
- *Moderate improvement necessary* – The area is generally functioning adequately, but some substantial opportunities for improvement were recommended.
- *Significant improvement necessary* – The area is not functioning adequately and many recommendations, requiring considerable effort, need to be implemented to achieve adequate performance.
- *Major improvement necessary* – The area is not functioning effectively or efficiently and many recommendations need to be implemented to achieve adequate performance. Implementation of these recommendations will have a major effect on cost levels and performance for PGW.

Exhibit I-1
Functional Evaluation Summary
Phase I – Diagnostic Review

Chapter	Function	Evaluative Ratings				
		Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
II	Executive Management & Human Resources					
	Executive Management		X			
	External Relations		X			
	Human Resources			X		
III	Support Services					
	Information Technology		X			
	Transportation Management			X		
	Facilities Management		X			
	Procurement Services				X	
	Risk Management		X			
	Legal Services		X			

Exhibit I-2
Functional Evaluation Summary
Phase II – Pre-identified Issues Review

Chapter	Function	Evaluative Ratings				
		Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
IV	Corporate Governance			X		
V	Financial Management			X		
VI	Diversity and EEO			X		
VII	System Reliability Performance & Other Related Operations			X		
VIII	Customer Service				X	

D. Summary of Estimated Benefits

The audit produced 93 recommendations, which are contained in this report. A summary of the number of priority items, and estimated benefits, is grouped by phase. Following is a brief explanation of these categories of information.

Priority

To assist PGW management in developing implementation plans, each recommendation has been assigned a priority of "high," "medium," or "low" according to the following criteria:

- *High* – Designated recommendations are high priority because of their importance and urgency. These represent significant benefit potential, major improvements to service, or substantial improvements to methods or procedures.
- *Medium* – Designated recommendations are of medium priority. In some instances, the implementation of these recommendations is expected to provide moderate improvements in profitability of operations, or management methods and performance. In other instances, implementation may provide significant longer-term benefits which are less predictable.
- *Low* – Designated recommendations reflect a lower priority. In many instances, they should be studied further or implemented sometime during the next few years. Potential benefits are perceived to be either modest or difficult to measure.

Exhibit I – 1
UGI Utilities, Inc.
UGI Central Penn Gas, Inc.
UGI Penn Natural Gas, Inc.
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance	X				
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations				X	
Electric Operations			X		
Emergency Preparedness			X		
Materials Management				X	
Customer Service		X			
Fleet Management		X			
Human Resources and Safety Programs		X			
Diversity			X		

D. Recommendation Summary

Chapters III through XIV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Effective implementation of the recommendations would result in cost savings, service improvements, and/or improvements in management practices and performance. Exhibit I–2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of these recommendations should begin within six months and be completed as soon as practical.
- MEDIUM PRIORITY – Implementation of these recommendations should begin within 12 months.
- LOW PRIORITY – Implementation of the recommendations should begin within 18 months.

Exhibit I-1
National Fuel Gas Distribution Corporation
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management & Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests			X		
Financial Management		X			
Emergency Preparedness		X			
Diversity & EEO		X			
Customer Service		X			
Gas Operations	X				

D. Recommendation Summary

Chapters III through X provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of the recommendation would result in significant cost savings, major service improvements, and/or substantial improvements in management practices and performance. These recommendations should be implemented as soon as practical.

- MEDIUM PRIORITY – Implementation of the recommendation would result in important cost savings, service improvements, and/or meaningful improvements in management practices and performance. Implementation of these recommendations should begin within 12 months.

- LOW PRIORITY – Implementation of the recommendation could potentially enhance cost controls, service improvements, and/or management practices and performances. Implementation of these recommendations should begin within 18 months.

These priorities were assigned based on the Audit Staff's assessment of the potential impact of the recommendations and the Companies' available resources.

Exhibit I-2
Functional Evaluation Summary
Phase I – Diagnostic Review

Chapter	Function	Evaluative Ratings				
		Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
II	Executive Management & Human Resources					
	Executive Management			X		
	Human Resources			X		
III	Financial Management		X			
IV	Support Services					
	Information Technology			X		
	Transportation Management		X			
	Facilities Management		X			
	Procurement Services		X			
	Risk Management		X			
	Legal Services		X			
V	Gas Supply & Operations			X		

Exhibit I-3
Functional Evaluation Summary
Phase II – Pre-identified Issues Review

Chapter	Function	Evaluative Ratings				
		Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
VI	Corporate Governance		X			
VII	Affiliate Interests					X
VIII	Operational Performance				X	
IX	Customer Service	X				
X	Diversity & EEO			X		

Exhibit I-1
PECO Energy Company
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure			X		
Corporate Governance		X			
Affiliated Interest and Cost Allocations		X			
Financial Management		X			
Electric Operations			X		
Gas Operations			X		
Emergency Preparedness		X			
Materials Management			X		
Customer Service			X		
Information Technology	X				
Fleet Management		X			
Facilities Management	X				
Risk Management	X				
Legal		X			
Human Resources and Diversity		X			

D. Benefits

Where possible, the Audit Staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of approximately $2,933,000 to $5,667,000 in annual savings and $2,200,000 to $3,110,000 in one-time savings from effective implementation of the recommendations. We try to identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues; whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty, and could be higher or lower than the amounts estimated by the Audit Staff. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Columbia Gas of Pennsylvania, Inc.

Customer Satisfaction and First Call Resolution Statistical History

2010				2011				2012				2013				2014		
Cust. Sat.	1st Call Res.	Ease of Conducting Business	2011	Cust. Sat.	1st Call Res.	Ease of Conducting Business	2012	Cust. Sat.	1st Call Res.	Ease of Conducting Business	2013	Cust. Sat.	1st Call Res.	Ease of Conducting Business	2014	Cust. Sat.	1st Call Res.	Ease of Conducting Business
95%	82%	85%	Jan	94%	74%	96%	Jan	100%	88%	98%	Jan	93%	81%	90%	Jan	98%	78%	97%
94%	71%	97%	Feb	96%	76%	86%	Feb	97%	79%	82%	Feb	93%	83%	91%	Feb	100%	81%	95%
96%	61%	94%	Mar	93%	90%	94%	Mar	96%	88%	97%	Mar	96%	80%	94%	Mar	94%	84%	96%
95%	74%	97%	Apr	96%	94%	97%	Apr	96%	79%	88%	Apr	100%	84%	97%	Apr	98%	69%	96%
98%	69%	95%	May	97%	86%	94%	May	95%	83%	85%	May	95%	70%	95%	May	99%	76%	99%
91%	65%	91%	Jun	95%	75%	86%	Jun	93%	69%	85%	Jun	93%	67%	86%	Jun	98%	84%	88%
94%	67%	79%	Jul	93%	72%	87%	Jul	90%	80%	89%	Jul	89%	79%	91%	Jul	97%	75%	93%
97%	68%	92%	Aug	93%	79%	72%	Aug	98%	80%	72%	Aug	99%	85%	85%	Aug	99%	82%	98%
97%	77%	87%	Sep	90%	84%	88%	Sep	97%	70%	74%	Sep	97%	75%	88%	Sep	94%	78%	91%
95%	73%	90%	Oct	93%	85%	80%	Oct	98%	79%	89%	Oct	96%	79%	88%	Oct	94%	81%	90%
95%	71%	92%	Nov	93%	69%	96%	Nov	93%	79%	93%	Nov	88%	77%	92%	Nov	96%	72%	91%
89%	72%	97%	Dec	97%	78%	91%	Dec	100%	88%	92%	Dec	91%	70%	91%	Dec	96%	81%	92%
94%	71%	91%	YTD	94%	80%	88%	YTD	96%	80%	87%	YTD	94%	77%	91%	YTD	97%	79%	94%
91%	69%	86%	Target	91%	69%	87%	Target	92%	70%	88%	Target	93%	75%	89%	Target	93%	75%	89%
94%	71%	91%	12 Month Avg	94%	80%	88%	12 Month Avg	96%	80%	87%	12 Month Avg	94%	77%	91%	12 Month Avg	97%	79%	94%

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
AMY L. EFLAND
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Table of Contents

I. Introduction 1

II. Weather Normalization Process 3

III. Forecast Method 9

IV. Trend in Residential Use Per Customer 12

I. Introduction

Q. Please state your name and business address.

A. My name is Amy L. Efland and my business address is 290 W. Nationwide Blvd. Columbus, OH 43215.

Q. By whom are you employed and in what capacity?

A. I am a Lead Forecasting Analyst for the NiSource Corporate Services Company.

Q. What are your responsibilities as Lead Forecasting Analyst?

A. I assist with the development of short-range and long-range forecasts of customers, energy consumption and peak demand for seven NiSource gas distribution companies, including Columbia Gas of Pennsylvania ("Columbia" or the "Company") and one NiSource electric company. I also assist with other business related analyses and forecasts.

Q. What is your educational and professional background?

A. I attended Earlham College where I earned a Bachelor of Arts Degree in Economics and Miami University where I earned a Master of Arts Degree in Economics. From 1997 to 2002, I worked as a forecast analyst for Cinergy, assisting with the production of the gas and electric long-term forecasts of customers, energy consumption and peak demand for the Cinergy (Public Service Indiana, Union Light, Heat & Power, and Cincinnati Gas & Electric) territories. I was promoted to Lead Analyst in 2002, a position I held until I left Cinergy in 2005. From 2005 to 2006, I worked as a Senior Forecasting Analyst with Limited Brands/Victoria's

Secret Direct. I provided analysis and recommendations surrounding circulation levels of catalogues and assisted with catalogue messaging relating to marketing offers. From 2006 to 2008, I worked as a Senior Marketing Analyst for JP Morgan Chase where I was responsible for the development of test designs for consumer and business banking marketing programs. I joined NiSource in 2008 as a Senior Forecast Analyst. In 2014, my title was changed to Lead Forecasting Analyst reflecting the same responsibilities I held while a Senior Forecast Analyst.

Q. Have you testified before this or any other Commission?

A. Yes, I have provided direct testimony related to weather normalization and customer usage trends before the Pennsylvania Public Utility Commission ("Commission"), Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274 and the Kentucky Public Service Commission, Case No. 2009-00141.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2014 as the Historic Test Year, the twelve-month period ending November 30, 2015 as the Future Test Year, and the twelve-month period ending December 31, 2016 as the Fully Forecasted Rate Year.

Q. What is the purpose of your testimony in this proceeding?

A. I will explain how residential and commercial sales are normalized for weather. The results of the normalization process are contained in Company witness Lai's

testimony (Columbia Statement No. 3) and Exhibit 3 Schedule 4. I will also explain sales growth and comment on the residential consumption per customer.

II. Weather Normalization Process

Q. Please explain the weather normalization process.

A. For each month of the Historic Test Year for the residential and commercial classes, actual billing month sales per customer is separated into base-usage and temperature-sensitive usage. Temperature-sensitive usage is then scaled by the ratio of normal to actual heating degree days ("HDD") to derive normal temperature-sensitive use per customer. The normal temperature-sensitive use per customer is then added to the base-use per customer to arrive at the normal sales per customer. This value is then multiplied by the customer count to derive the normal sales.

Q. What data sources did you use for your calculations?

A. I used the Company's billing records to obtain monthly customer counts and billed sales. The temperatures used to calculate HDD were obtained from National Weather Service weather stations throughout the Company's service territory. Due to the geographical dispersion of Columbia's customers, temperature data from multiple weather stations is used. A weighted average HDD for the Company is calculated using the percent of residential heating customers assigned to each station as a weight for that station.

Q. How does the process calculate base usage?

A. The process assumes no temperature sensitive (heat) usage in July and August. For September, no temperature sensitive (heat) use is assumed when total use per customer per day (Total Use/Customer/Day) is less than July and/or August. The base use per customer per day is calculated by taking the average of the two lowest observed values from the months of July through September.

Q. How does the process weather normalize monthly sales?

A. First, the monthly base use per customer is determined. This equals the lesser of the base use per customer per day multiplied by the days in the billing cycle ((base use /customer/day)*days in billing cycle) or the monthly total use per customer. Second, monthly heat use per customer is calculated. Heat use per customer equals the total use per customer minus the base use. Third, the heat use per customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD. Finally, normal use per customer is calculated by adding the base use per customer to the normal heat use per customer. Total monthly normalized usage is generated by multiplying monthly customers by the monthly normal use per customer. This calculation for the Historic Test Year is prepared separately for residential and commercial customers and the results are presented in Exhibit 10, Schedule 8.

Q. Has the process for normalizing weather changed from Columbia's last rate filing?

A. No—not other than updating the historic averages to include the most recent 20-year history. Normal weather is defined in this filing as the average HDD for the 20 years ended 2013. The previous base rate case filing defined normal weather as the

20-year average ending in 2012. In all other respects, the normalization process is the same.

Q. Why is Columbia using the 20-year average?

A. The settlement of the Company's 2014 base rate proceeding at Docket No. R-2014-2406274 designed rates based upon the Company's proposed throughput volumes, which reflected the Company's use of the 20-year average. Consistent with the Company's approach since 2008, the Company proposes to continue to use the 20-year average because an analysis of weather data shows that a rolling 20-year average is a superior measure to a rolling 30-year average. Table 1 below illustrates that, as a predictor of one-year-ahead weather, the 20-year average outperforms the 30-year average in 71% of the most recent 35 years. Table 1 also illustrates that the 20-year average has a lower mean absolute error, as compared to the 30-year average when considering both the most recent 35 year period and the most recent 10 year period.

In Table 2, the averages are used every year to predict each five year period for the 5-years ended 1985 through the five years ended 2014. In this analysis, the performance of the 20-year averages are compared to the 30-year average. When determining the smallest difference over the 5-year period, the 20-year average outperforms the 30-year average in 83% or 25 out of the 30 periods. When considering the most recent 10 periods, the 20-year average outperforms the 30-year average in 100% or all of the 10 periods.

Table 3 demonstrates that stability is not sacrificed when using a 20-year average. The average annual change for the 20-year average is 0.4%, while the average annual change for the 30-year averages is 0.3%. The 20-year normal is not only a better predictor, but also a more dynamic measure that is better able to react more quickly to change because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average. This is particularly important, given the Company's frequent rate case filings. In conclusion, the 20-year measure performs better as compared to the 30-year in both the year ahead analysis and the five year analysis, and is both a better predictor and a more dynamic measure when compared to the 30-year average.

Table 1
Weather Averages as Predictors
Moving Averages used to Predict Following Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Absolute Error		Better 1-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1980	6010	5877	5766				
1981	6219	5887	5790	342	453	x	
1982	5915	5880	5811	28	125	x	
1983	5568	5848	5831	312	243		x
1984	6064	5860	5853	216	233	x	
1985	5236	5831	5845	624	617		x
1986	5571	5818	5839	260	274	x	
1987	5456	5796	5838	362	383	x	
1988	5892	5791	5835	96	54		x
1989	5724	5778	5833	67	111	x	
1990	5071	5737	5808	707	762	x	
1991	4908	5692	5771	829	900	x	
1992	5558	5680	5755	134	213	x	
1993	5455	5693	5730	225	300	x	
1994	5719	5709	5726	26	11		x
1995	5427	5706	5713	282	299	x	
1996	6005	5704	5719	299	292		x
1997	5641	5681	5711	63	78	x	
1998	4590	5601	5664	1091	1121	x	
1999	5166	5560	5637	435	498	x	
2000	5403	5529	5621	157	234	x	
2001	5385	5488	5606	144	236	x	
2002	5304	5457	5590	184	302	x	
2003	5825	5470	5611	368	236		x
2004	5329	5433	5608	141	282	x	
2005	5564	5450	5611	131	44		x
2006	5175	5430	5582	275	436	x	
2007	5295	5422	5555	135	287	x	
2008	5526	5404	5533	104	29		x
2009	5447	5390	5515	44	86	x	
2010	5400	5406	5495	10	115	x	
2011	5421	5432	5468	15	74	x	
2012	4669	5387	5426	763	799	x	
2013	5486	5389	5424	99	60		x
2014	5950	5400	5420	561	526		x

	Mean Absolute Error		Frequency of Lowest Absolute Error	
1981-2014	280	315	24	10
2005-2014	214	246	6	4

Relative Frequency of Lowest Absolute Error

1981-2014	71%	29%
2005-2014	60%	40%

Table 2
Weather Averages as Predictors
Moving Averages used to Predict the Following Five Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Five Year Sum of Errors		Better 5-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1980	6010	5877	5766				
1981	6219	5887	5790				
1982	5915	5880	5811				
1983	5568	5848	5831				
1984	6064	5860	5853				
1985	5236	5831	5845	-382	173		x
1986	5571	5818	5839	-1080	-597		x
1987	5456	5796	5838	-1506	-1159		x
1988	5892	5791	5835	-1022	-937		x
1989	5724	5778	5833	-1422	-1386		x
1990	5071	5737	5808	-1442	-1512	x	
1991	4908	5692	5771	-2040	-2146	x	
1992	5558	5680	5755	-1827	-2038	x	
1993	5455	5693	5730	-2239	-2458	x	
1994	5719	5709	5726	-2179	-2454	x	
1995	5427	5706	5713	-1619	-1975	x	
1996	6005	5704	5719	-297	-693	x	
1997	5641	5681	5711	-151	-529	x	
1998	4590	5601	5664	-1083	-1268	x	
1999	5166	5560	5637	-1715	-1803	x	
2000	5403	5529	5621	-1725	-1762	x	
2001	5385	5488	5606	-2334	-2412	x	
2002	5304	5457	5590	-2557	-2706	x	
2003	5825	5470	5611	-924	-1236	x	
2004	5329	5433	5608	-553	-937	x	
2005	5564	5450	5611	-240	-696	x	
2006	5175	5430	5582	-241	-835	x	
2007	5295	5422	5555	-98	-760	x	
2008	5526	5404	5533	-461	-1165	x	
2009	5447	5390	5515	-159	-1035	x	
2010	5400	5406	5495	-405	-1212	x	
2011	5421	5432	5468	-60	-820	x	
2012	4669	5387	5426	-646	-1313	x	
2013	5486	5389	5424	-595	-1244	x	
2014	5950	5400	5420	-22	-649	x	

	Mean Error		Frequency of Lowest Error	
1985-2014	-1034	-1319	25	5
2005-2014	-293	-973	10	0

Relative Frequency of Lowest Error		
1985-2014	83%	17%
2005-2014	100%	0%

Table 3

Stability of Weather Averages Annual Change in Averages 1981-2014 Absolute Values Columbia Gas of Pennsylvania			
	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.7%
Maximum	1.4%	0.8%	18.6%

III. Forecast Method

Q. Please explain the methodology employed for developing the forecasted number of customers and customer usage for the Future Test Year and the Fully Forecasted Rate Year.

A. Development of the forecasting methodology is presented in the following summary. This method was used to develop both the Future Test Year and the Fully Forecasted Rate Year. Price information included in the models is from the Company's databases, and average efficiency data is from Itron Inc., a national utility consulting firm. The economic variables and deflator information is from IHS Global Insight, Inc., a data consultant, and weather data is provided by Schneider Electric, a weather consulting service.

Residential and Commercial Customers

- Total new customer additions are forecasted for the initial three years of the forecast by Columbia's New Business Team. CHOICE customers are calibrated to

the most recently observed level and the forecast is set to the current observed percentage of customers participating in the CHOICE program.

- Traditional transportation customers = existing transportation customers + new customers identified by the Large Customer Relations group.
- Existing customers are forecasted using the latest historical level. The forecast is calculated by applying an attrition rate calculated using recent historical data. The attrition rate is applied to the latest existing level of customers at the time the forecast is being prepared. The attrition rate used for the Future Test Year and Fully Forecasted Rate Year is 0.4% for Residential and 1.1% for Commercial.
- Total customers = existing customers + new customers – attrition customers
- Sales customers = total customers – CHOICE customers – traditional (commercial) transportation customers

Residential Dth/customer

- Residential use per customer is forecasted with an econometric model that incorporates real price, an average efficiency variable, real per capita income, and heating degree days. Residential CHOICE usage follows the total Residential usage trend.

Residential Volume

- Dth is forecasted for existing and new construction customers

  Dth = customers * Dth/customer

- CHOICE Dth forecasted as

  CHOICE Dth = customers * Dth/customer

- Sales Dth forecasted as residual

  Sales Dth = Dth – CHOICE Dth

Commercial Dth/customer

- Commercial use per customer is forecasted with an econometric model that incorporates real price, real gross county product, average efficiency variable, and heating degree days. Commercial CHOICE usage follows the total Commercial usage trend.

Commercial Dth

- Dth is forecasted for existing and new construction customers

  Dth = customers * Dth/customer

- CHOICE Dth is forecasted as

  CHOICE Dth = customers * Dth/customer

- Non-CHOICE transportation Dth for large commercial customers is forecasted by the Large Customer Relations group. Non-CHOICE transportation Dth for smaller commercial customers is forecasted as the trend in the forecast for total commercial use per customer.

- Sales Dth forecasted as residual

  Sales Dth = Dth – CHOICE Dth – non-CHOICE transportation

Industrial Volume

- The majority of the Industrial class forecast is provided by the Large Customer Relations group. This portion constitutes 91% of the total Industrial class forecast. The large customer portion of the forecast is developed by incorporating

information generated through individual customer interviews. The remainder of the industrial class forecast is estimated using the trend from an econometric model for the full class. The model incorporates real price, manufacturing employment, industrial production, and heating degree days. The total industrial volume forecast is the sum of the large industrial forecast and the all other industrial forecast.

- The information provided through the interviews with customers, in addition to the small customer analysis, provides the sales/transportation split of Dth. Additional transportation Dth is forecasted with the trend from the econometric model.

Q. Please discuss the past performance of the forecast.

A. Residential and commercial forecast models are updated annually with the most current data. An internal review of forecast performance occurs on a regular basis. Variances for the residential and commercial predictions are calculated and assessed in order to measure accuracy. The average annual one year weather normalized variance for the residential models is 0.4%. For commercial, the average one year variance of the forecast is 1.6%.

IV. Trend in Residential Use Per Customer

Q. Describe Columbia's recent trends related to residential use per customer.

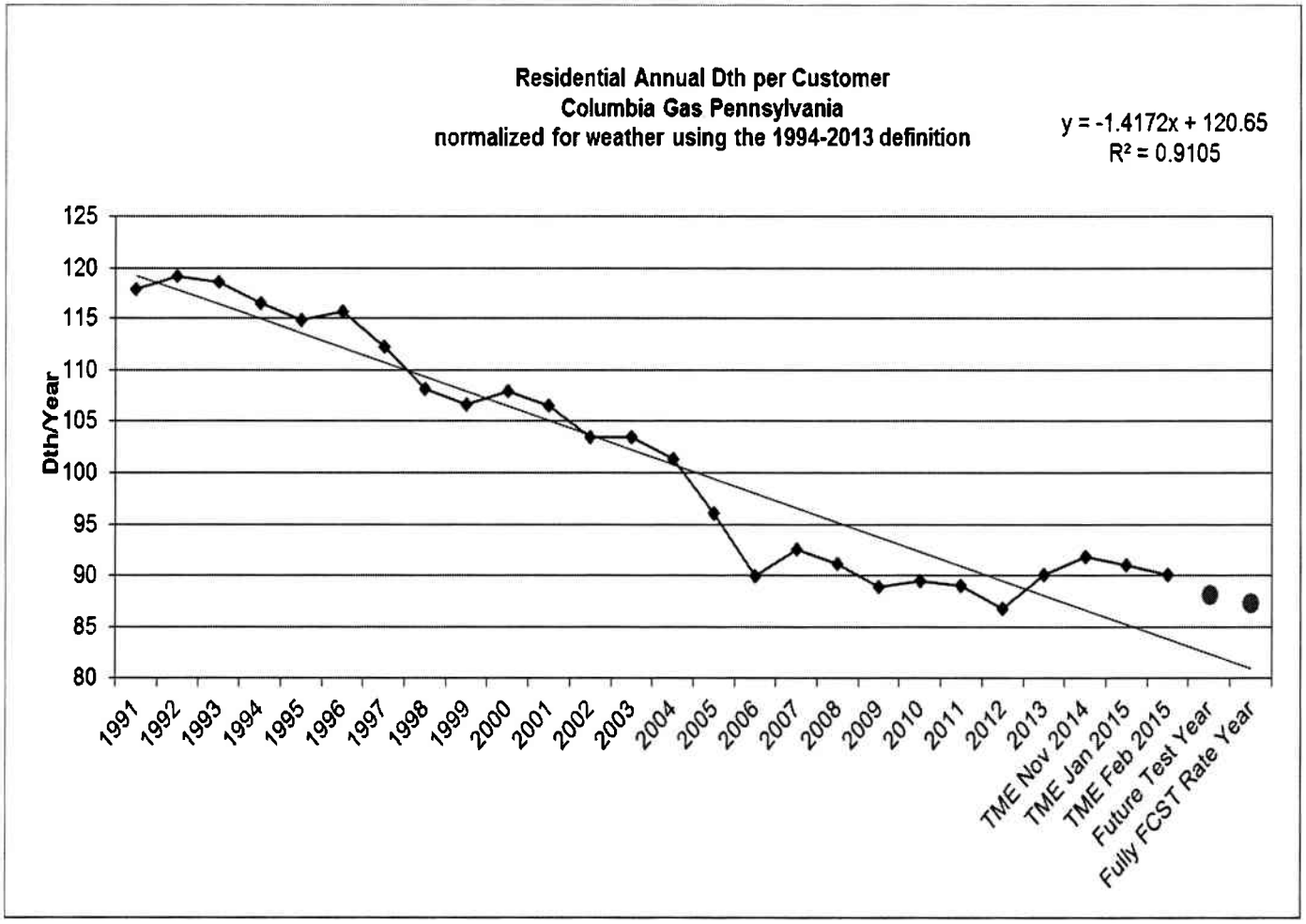
A. Historical data shows that there has been a steady decline since 1991 in residential use per customer with only a few years exhibiting an increase in use. These periods of increase in use were all followed by periods with decreased usage, indicating that

these points were not representative of the overall trend. Customer usage in years 2010 and 2011 illustrates the trend in declining usage. Although usage appears to flatten out during this period, when taking into account 2012, there is a decline of 2.5% from 2011. Usage falls from 89.0 Dth in 2011 to 86.8 Dth in 2012, supporting the overall trend and decline in usage.

Unusually warm weather during the winter of 2011-2012 resulted in a consumption response, as measured by temperature sensitive use per customer per heating degree day from residential customers that was notably below that of recent years. This was followed by unusually cold weather during the winter of 2012-2013 and 2013-2014 that resulted in a consumption response notably above that of recent years. With the return of more temperate weather, usage should smooth out and reveal the continuation of the underlying downward trend. This can already be seen when comparing the level of usage for the twelve month period ending November 2014 with usage for the twelve month period ending January 2015. Residential use per customer drops from 91.83 Dth for TME November 2014 to 91.00 Dth for TME January 2015, reflecting nearly a 1% drop. When considering the usage level of 90.13 Dth for the twelve month period ending February, the drop is close to 2% compared to the TME November 2014 level of 91.13 Dth. This trend is projected to continue with the return of more moderate weather. The Forecasted Test Year and the Fully Forecasted Rate Year usage projections can be found in Exhibit No. 10 Schedule 2 on pages 7 and 8 and are included in the chart below. The Future Test Year usage level of 88.18 Dth and the Fully Forecasted Rate Year

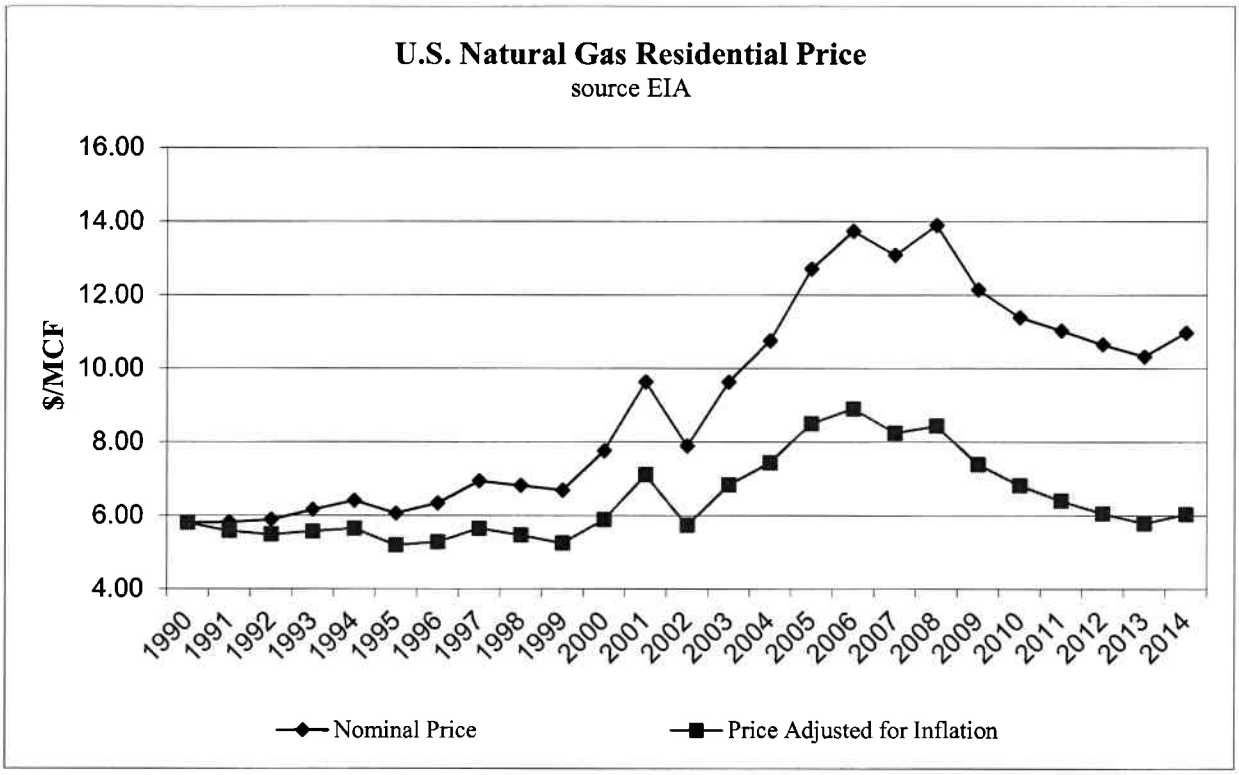
usage level of 87.36 Dth reflect the historical use per customer trend and are in line with more recent data. The points represent a decline in usage from the Historic Test Year acknowledging the overall downward trend in usage but both the Future Test Year and the Fully Forecasted Rate Year usage levels are above the data trend line and reflect current levels.

Residential use per customer trends are depicted in the chart below:



Q. What factors are causing the reduction in residential customer usage?

A. Throughout most of the 1990s natural gas consumption per residential customer decreased by 1% to 2% per year. This decline in consumption occurred in spite of a relatively constant nominal price, as is illustrated in the graph below.



When adjusted for inflation, the price actually decreased during the 1990s. This conservation was a result of increased appliance efficiency and more efficient construction standards that followed the major price increases that occurred in the 1970s and 1980s. Annual conservation increased significantly as a result of the large natural gas price increases that occurred in the winters of 2000-2001, 2004-2005, and 2005-2006. With limited end uses for natural gas, increasing appliance efficiency, and higher building standards, the downward trend in consumption per

customer will continue. Appliance choice will also affect the trend. Customers choosing high efficiency furnaces, energy efficient gas water heaters and electric appliances such as electric water heaters, heat pumps and cooking ranges, will also contribute to the downward trend.

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
CHUN-YI LAI
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

I. Introduction

Q. Please state your name and business address.

A. Chun-Yi Lai, 240 West Nationwide Blvd., Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as a Lead Regulatory Analyst. My responsibilities include providing support for various informational and rate flings, general rate case preparation and support, and other duties as assigned. NCSC provides, among other services, accounting and regulatory-related services for the NiSource Gas Distribution ("NGD") companies, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Please briefly describe your educational and professional background.

A. In June 2006, I graduated from The Ohio State University with a Bachelor of Science Degree in Business Administration with a major in Finance.

My career with NiSource began when I was hired as a Financial Analyst in Accounting with Columbia Pipeline Group, and was later promoted to a Senior Financial Analyst in October, 2008. In May 2011, I accepted a position as Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department. I was promoted to my current position as Lead Regulatory Analyst in October, 2014.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory commission?

A. I have not previously testified before the Commission. However, I have submitted

direct and rebuttal testimony with the Virginia State Corporation Commission in Case No. PUE-2014-00020.

Q. Please explain the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to support and discuss the development of revenues to be used in the cost of service. I will sponsor Exhibit 3 and 103, with the exception of Schedule 8 (Rate Design) which is sponsored by Company witness Mark P. Balmert.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2014 as the Historic Test Year, the twelve-month period ending November 30, 2015 as the Future Test Year, and the twelve-month period ending December 31, 2016 as the Fully Forecasted Rate Year.

II. Operating Revenues – Exhibit 3

Q. Please explain the process that was undertaken to produce the number of bills for the Historic Test Year.

A. The number of bills was summarized by rate schedule in Exhibit 3 Schedule 2 on a customer-by-customer, and month-by-month basis. The bills, as shown in column 1, were accumulated based on the rate schedule the customer was on at November 30, 2014. Adjustments were made in Exhibit 3 Schedule 2 Column 2 to reflect discontinued or added services for larger commercial and industrial customers. Incremental residential and commercial customers that were added or discontinued

during the historic test year are shown in column 3 and 4, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the Historic Test Year can be found in Exhibit 3 Schedule 5 Pages 1 – 5. Furthermore, an adjustment is made to add final billed customers because they were coded as inactive and were not counted for the month even though they were billed a customer charge for their final month of service.

Q. Please explain the development of the adjusted volumes in Dekatherm ("Dth") for the Historic Test Year.

A. Physical flow volumes were summarized by rate schedule in Exhibit 3 Schedule 3 on a customer-by-customer, and month-by-month basis. The volumes, as shown in column 1, were accumulated based on the rate schedule the customer was on at November 30, 2014. The Weather Normalization Adjustment in Exhibit 3 Schedule 3 Column 2 represents the change to physical flow volumes due to the use of a 20-year weather definition normalization. Adjustments were made in Exhibit 3 Schedule 3 Column 3 to reflect discontinued or added services for larger commercial and industrial customers. Incremental residential and commercial customers that were added or discontinued during the historic test year are shown in columns 4 and 5, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the Historic Test Year can be found in Exhibit 3 Schedule 5 Pages 1 – 5.

Q. Please explain why physical flow volumes were used instead of invoiced volumes as

the basis for calculating operating revenues.

A. Physical flow volumes were used instead of invoiced volumes because they represent volumes that flowed during the test year. Invoiced volumes may include adjustments made for prior billing periods that are outside of the Historic Test year. Therefore, physical flow volumes were used to eliminate out of period adjustments.

Q. How is the 20-year weather normalization definition utilized in Exhibit 3 Schedule 4?

A. Company witness Amy L. Efland (Columbia Statement No. 2) provided the total normalized volumes by month for residential and commercial customers, and they were allocated based on the customers' actual physical flow volumes and by their class. They were then accumulated by rate schedule by rate block, if applicable, as shown in Exhibit 3 Schedule 4 Column 2. The weather adjustment in Column 3 is calculated by subtracting actual physical flow Dth in column 1 from the normalized Dth in Column 2. The revenue impact as shown in column 5 is determined by multiplying the Dth in column 3 by the current base rates.

Q. Please explain the elimination of off-system sales in Exhibit 3 Schedule 6.

A. The elimination of off-system sales is a standard pro-forma adjustment and has been accepted by the Commission in prior rate case proceedings. Revenue from off-system sales was eliminated because it is not a basis for determining the Company's revenue requirement.

Q. Please explain the elimination of unbilled revenue and gas cost from the Historic

Test Year.

A. Unbilled revenue and gas cost are estimated revenues from services rendered to customers, but not yet billed by the Company. It is simply an accounting estimate to establish a calendar level of revenue to be recorded on the books. The purpose of this elimination is to reflect "as billed" revenue and gas cost during the twelve monthly billing cycles of the Historic Test Year.

Q. Please explain Schedules 8 and 9 in Exhibit 3.

A. Schedules 8 and 9 in Exhibit 3 demonstrate the calculation of gas cost, Gas Procurement Charge ("GPC"), Rider Universal Service Plan ("USP") and Merchant Function Charge ("MFC") by multiplying physical flow Dth with the rates that were effective in the Historic Test Year. The result of the calculation is used to split the per books revenue by customer class.

Q. Were current rates used in calculating revenues in Exhibit 3, Schedule 1?

A. Yes, current rates as of January 1, 2015 were used to calculate revenues with the exception of the MFC. This particular rider was calculated by using a three year average charge-off rate by revenue class for Residential Sales Service and Small General Sales Service. Please refer to Exhibit CYL-1, attached to this testimony, for the calculation. Company witness Kelley K. Miller (Columbia Statement No. 4) provides support for the calculation of the charge-off rates for uncollectible accounts.

Q. Please explain the adjustment made to Forfeited Discounts Account 487 in Exhibit

3, Page 9, Column 10.

A. A historic three year average percentage of Forfeited Discounts revenue to billed revenue is applied to the total annualized revenue, resulting in an annualized historic test year level of Forfeited Discounts. The calculation can be found in Exhibit CYL-2, Page 1, which is attached to this testimony.

Q. Please explain Pages 6 – 8 of Exhibit 3.

A. The summary shows a comparison of the adjusted bills and volumes by customer class priced at current and proposed rates.

III. Operating Revenues – Exhibit 103

Q. Please explain the process that was undertaken to produce the number of bills for the Future Test Year and Fully Forecasted Rate Year in Exhibit 103, Schedule 2.

A. Forecasted active customer counts are first determined on a total company basis by customer class by service type (Sales/Choice/Transportation) by month in Columbia's forecast supported by Columbia witness Efland. Large customers that are individually forecasted by the Large Customer Relations ("LCR") group are identified separately from the total forecast. The remaining non-LCR customer counts in the forecast are then spread for each month of the test year by service type by customer class by rate schedule based on the latest twelve months of historical experience ending November 30, 2014. The bills are accumulated based upon which rate schedule the customer was on at November 30, 2014.

Incremental residential and commercial customers that are expected to be

added or discontinued during the forecasted test years are shown in columns 3 and 4, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the Future Test Year and Fully Forecasted Rate Year can be found in Exhibit 103, Schedule 4.

Furthermore, an adjustment is made in Column 6 to reflect final billed customers because the forecast is based on projected active customers.

Q. Please explain the development of usage in Dth for the Future Test Year and Fully Forecasted Rate Year in Exhibit 103, Schedule 3.

A. Similar to the methodology used to produce the number of bills, forecasted Dth are first determined on a total company basis by customer class by service type by month in Columbia's forecast supported by Company witness Efland. Forecasted volumes associated with LCR customers is identified separately from the total forecast based upon the individual large customer forecast performed by the LCR group. The remaining non LCR volumes are then spread for each month of the forecasted test year by service type by customer class by rate schedule based on the latest twelve months of historical experience ending November 30, 2014. Volumes are accumulated based upon which rate schedule the customers were on November 30, 2014.

Incremental residential and commercial customers expected to be added or discontinued during the forecasted test years are shown in column 3 and 4, respectively, for a full year impact. The corresponding backup for customer

additions and attrition for the Future Test Year and Fully Forecasted Rate Year can be found in Exhibit 103, Schedule 4.

Q. Have any changes been made to how the Rider USP is calculated in Exhibit No. 103, Schedule No. 7?

A. The Rider USP is calculated by taking the revenue increase for Customer Assistance Program ("CAP") class divided by the volumes for Residential Sales Service ("RSS") and Residential Distribution Service ("RDS"). The calculation also includes an adjustment for the $770,000 expenses associated with the CAP program. The purpose of this adjustment is to shift the revenue increase from base rate recovery to recovery through Rider USP. Please see Company witness Nancy J.D. Krajovic's testimony (Columbia Statement No. 12) for details behind the proposed changes.

Q. Please explain the adjustment made to Forfeited Discounts Account 487 in Exhibit 103, Page 10, Column 8 for the Future Test Year and Page 14, Column 8 for the Fully Forecasted Rate Year.

A. As mentioned before in Page 5 of my testimony, the Company is utilizing a three year average to get to an annualized level of Forfeited Discounts. Please see Exhibit CYL-2, Page 2 and 3 for the annualization adjustment.

Q. Please explain Pages 6 – 9 of Exhibit 103.

A. The summary shows a comparison of the adjusted bills and volumes by customer class priced at current and proposed rates for the Future Test Year and Fully Forecasted Rate Year.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Calculation of Merchange Function Charge Utilized in Exhibit No. 3 and Exhibit No. 103
Calculated Using Gas Costs as of January 1, 2015

Line	Description	Reference	Rate $
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/15 Quarterly GCR Filing)	4.5061
2	Off System Sales & Capacity Release Credit	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 6 (1/01/15 Quarterly GCR Filing)	(0.1052)
3	Total Commodity Cost of Gas per Dth		**4.4009**
4	Merchant Function Ratio[1] - Resdential Sales Service	Exhibit No. 4, Schedule No. 2, Page 32, Line 7	0.0154
5	Merchant Function Ratio[1] - Small General Sales Service	Exhibit No. 4, Schedule No. 2, Page 32, Line 14	0.0045
6	Merchant Function Charge - Residential Sales Service per Dth	(Line 3 x Line 4)	0.0676
7	Merchant Function Charge - Small General Sales Service per Dth	(Line 3 x Line 5)	0.0196

[1] Per Order in Docket No. R-2012-2321748

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2014

Line No.		12 Mos November 2012	12 Mos November 2013	12 Mos November 2014	Total 3 Year Average		
1	Per Books Acct 487	$ 887,764	$ 1,144,228	$ 1,321,479	$ 3,353,471		
2	Per Books Billed Revenue	$ 366,906,958	$ 446,111,765	$ 542,904,735	$ 1,355,923,458		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2420%	0.2565%	0.2434%	0.2473%		
4	Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 6)					$	408,640,731
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)					$	136,322,402
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	544,963,133
7	3 Year Average						0.2473%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,347,694
9	Historic Test Year Acct 487 (Ex. 3, Page 9)					$	1,321,479
10	Annualization Adjustment (Line 8 - Line 9)					$	26,215

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2015

Line No.		12 Mos November 2012	12 Mos November 2013	12 Mos November 2014	Total 3 Year Average		
1	Per Books Acct 487	$ 887,764	$ 1,144,228	$ 1,321,479	$ 3,353,471		
2	Per Books Billed Revenue	$ 366,906,958	$ 446,111,765	$ 542,904,735	$ 1,355,923,458		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2420%	0.2565%	0.2434%	0.2473%		
4	Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)					$	398,882,497
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)					$	133,671,364
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$	532,553,861
7	3 Year Average						0.2473%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$	1,317,006
9	Future Test Year Acct 487 (Ex. 103, Page 10)					$	1,347,694
10	Annualization Adjustment (Line 7 - Line 8)					$	(30,688)

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2016

Line No.		12 Mos November 2012	12 Mos November 2013	12 Mos November 2014	Total 3 Year Average		
1	Per Books Acct 487	$ 887,764	$ 1,144,228	$ 1,321,479	$ 3,353,471		
2	Per Books Billed Revenue	$ 366,906,958	$ 446,111,765	$ 542,904,735	$ 1,355,923,458		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2420%	0.2565%	0.2434%	0.2473%		
4	Fully Forecasted Rate Year Sales Revenue (Ex. 103, Page 15, Line 5)					$	398,548,264
5	Fully Forecasted Rate Year Transportation Revenue (Ex. 103, Page 15, Line 8)					$	134,437,426
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	532,985,690
7	3 Year Average						0.2473%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,318,074
9	Fully Forecasted Rate Year Acct 487 (Ex.10 3, Page 14)					$	1,317,006
10	Annualization Adjustment (Line 8 - Line 9)					$	1,068

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
KELLEY K. MILLER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Table of Contents

I. Introduction 1

II. Statement of Purpose 3

III. HTY – Exhibit 2 – Statement of Income 5

IV. HTY – Exhibit 4 - Operation & Maintenance Expenses 6
- A. Rate Case Expense Removal 8
- B. Removal of Polypipe 9
- C. Labor 9
- D. Incentive Compensation 10
- E. OPEB – Other Post Employment Benefits 10
- F. Rents and Leases 11
- G. Corporate Insurance 11
- H. Injuries and Damages 12
- I. Company Memberships 12
- J. Utilities and Fuel Used in Company Operations 13
- K. Advertising 13
- L. Commission, OCA, OSBA Assessments 14
- M. NiSource Corporate Services Company "NCSC" 14
- N. Deferred OPEB Refund Amortization 22
- O. NCSC OPEB Amortization 23
- P. NiFiT Expense 23
- Q. NiFiT Amortization 24
- R. Lobbying Expense 24
- S. Charitable Contributions 25
- T. Rate Case Expense Normalization 25
- U. Uncollectible Accounts Expense 26
- V. Normal Uncollectible Accounts 26
- W. Rider USP Costs 29
- X. Interest on Customer Deposits 30

V. FTY/FFRY – Exhibit 102 – Statement of Income 30

VI. FTY/FFRY – Exhibit 104 – Operations and Maintenance Expense 32
- A. Labor 36
- B. Pension Expense 36

C. OPEB – Other Post Employment Benefits 37
D. Outside Services - Polypipe Adjustment 39
E. Rents and Leases 39
F. Injuries and Damages 40
G. Utilities and Gas Used in Company Operations 40
H. Advertising 40
I. NiSource Corporate Services Company "NCSC" 41
J. OPEB Deferral Passback Amortization Adjustment 42
K. NiFiT Expense Adjustment 42
L. NiFiT Non-Labor Amortization Adjustment 43
M. Lobbying Expense 44
N. Normalization – Rate Case Expenses 44
O. Normal Uncollectible Accounts Expense 44
P. Total Rider USP Costs 45
Q. Other Adjustments to the FFRY 46

I. Introduction

Q. Please state your name and business address.

A. Kelley K. Miller, 290 Nationwide Blvd, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), as a Lead Regulatory Analyst.

Q. What are your responsibilities as a Lead Regulatory Analyst?

A. My primary responsibilities include providing support for regulatory filings for several NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Maryland and Columbia Gas of Massachusetts. The types of filings include rate cases and various rate filings. My other regular duties include account reconciliations, assisting in the planning process, providing assistance, training and oversight to other regulatory analysts and other duties as assigned.

Q. What is your educational and professional background?

A. I graduated cum laude from Ohio Wesleyan University with a Bachelor's of Arts degree in Accounting and Economics with Management Concentration in 1985. I began my professional career with the Columbia Gas System in Columbus, Ohio in 1986, beginning in the Management Information Department as an Accountant. I was promoted to Senior Accountant in 1987 in the Consolidation Accounting Department of the Columbia Gas System in Wilmington, Delaware. In 1989, I was

offered and accepted a promotion to the position of Lead Accountant for Columbia Gas of Ohio as a member of Columbia Distribution Company's Financial Accounting and Reporting Architecture Team. As a member of this team, I was responsible for acting as a liaison between the Accounting departments and the project team that designed and implemented new accounting systems including the General Ledger, Employee Time Reporting and Labor Account Distribution. I remained in this role until all new systems were implemented in 1993. At that time, I was assigned the role of Lead Accountant for first Columbia Gas of Maryland, and then Columbia Gas of Pennsylvania. Responsibilities in this role included, but were not limited to coordinating the monthly closing process; preparing journal entries, preparing financial statements and overseeing and preparing account reconciliations. I remained in this role until 1997, when I decided to leave the workforce to start a family. During the years from 1997 to 2009 I remained out of full-time employment. In October of 2009, I accepted the position of Regulatory Analyst for NCSC. In April 2011, I was promoted to Senior Regulatory Analyst and in March of 2012, I was promoted to my current position as Lead Regulatory Analyst.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I was the Cost of Service witness for Columbia Gas of Pennsylvania, Docket No. R-2014-2406274.

II. Statement of Purpose

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to present Columbia's cost of service and to quantify an existing revenue deficiency based on Twelve Months Ended December 31, 2016 operating costs and revenues, as adjusted. As part of the cost of service analysis, my testimony supports all rate making adjustments to Columbia's Cost of Service Operating and Maintenance ("O&M") expenses.

Q. Would you please provide a listing of the exhibits that you are sponsoring through your testimony?

A. Yes. For the historic test year, I am supporting Exhibit 1, Exhibit 2, Exhibit 4, and Exhibit 408. For the future test year and fully forecasted rate year, I am sponsoring Exhibit 101, Exhibit 102, Exhibit 104 (in coordination with Company witness Hanson), and Exhibit 414. All of these exhibits were either prepared by me or under my direct supervision and control.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2014 as the "historic test year" or "HTY", the twelve-month period ending November 30, 2015 as the "future test year" or "FTY" and the twelve-month period ending December 31, 2016 as the "fully forecasted rate year" or "FFRY".

Q. What is the basis for Columbia's claim for revenue deficiency?

A. Columbia's revenue deficiency is calculated utilizing a rate year ending December 31, 2016 for rate base, revenues and expenses, with pro forma adjustments for known and measurable changes. This approach recognizes that a utility's revenues should be sufficient to recover the reasonably and prudently incurred costs of providing safe and reliable service to its customers, including a reasonable opportunity to earn a fair rate of return on the used and useful investment that the utility has devoted to such service.

Q. Would you please summarize the results of the cost of service requirement and resulting revenue deficiency?

A. As indicated on Exhibit 102, Schedule 3, Page 5, Columbia has a revenue deficiency of $46,172,483 based upon pro forma revenue requirement for the twelve months ending December 31, 2016. Columbia's computation of the revenue deficiency reflects total rate base of $1,325,130,928. In addition, the computation of the revenue deficiency reflects known and measurable changes to both utility operating income and rate base, which are explained later in my testimony and in the testimony of other Company witnesses.

Q. How is your following testimony organized?

A. I will first address the HTY, Exhibit 2 and Exhibit 4, followed by a discussion of the FTY and FFRY, Exhibit 102 and Exhibit 104.

III. HTY – Exhibit 2 – Statement of Income

Q. Please describe Exhibit 2, Schedule 3, Page 3.

A. This Exhibit is the statement of operating income, pro forma at present and proposed rates, for the HTY. Column 2 reflects the per book operating revenue, operating revenue deductions, income taxes and utility operating income for the Company for the twelve months ended November 30, 2014. These amounts have been adjusted to reflect pro forma operating income at HTY present rates in Column 4. Column 5 adjustments are detailed in Exhibit 2, Schedule 3, Page 6. Column 6 shows the resulting pro forma operating revenue, expenses and income for the HTY at proposed rates.

Q. Please describe the data inputs of Exhibit 2, Schedule 3, Page 3.

A. Operating revenues are supplied by Company witness Lai (Columbia Statement No. 3) and are included on lines 1 through 11. Witness Lai also provides the level of Gas Supply Expense and Off System Sales Expense that are included on lines 14 and 15. These two items are exactly offsetting to the level of revenue included in this case and accordingly do not impact the base rate claim in this case; rates for these items are determined in the Company's annual gas cost proceedings. I am supporting the Operating and Maintenance Expense level as presented on line 17. Lines 18 and 19, Depreciation and Amortization and Net Salvage Amortized are provided by Company witness Spanos (Columbia Statement No. 5). Taxes Other Than Income, Income Taxes and Investment Tax Credit, lines 20, 23 and 24 have been provided

by Company witness Fischer (Columbia Statement No. 10), and Rate Base on line 26 has been provided by Company witness Paloney (Columbia Statement No. 6). The Percentage Rate of Return at Proposed Rates on Line 27, Column 6 is provided by Company witness Moul (Columbia Statement No. 8). Each witness' testimony provides detailed support for each of these items.

Q. Please describe Exhibit 2, Schedule 3, Pages 4 through 6.

A. Page 4 shows pro forma interest expense as calculated by multiplying the Rate Base shown in Exhibit 8 by the weighted cost of short and long term debt shown in Exhibit 400, Schedule 1, Page 1.

Exhibit 2, Schedule 3, Page 5 shows the derivation of the Revenue Conversion Factor on lines 8 through 17. The Revenue Conversion Factor is then utilized to determine the Gross Revenue Requirement.

Page 6 shows the calculated adjustments to pro forma expenses and income taxes to achieve the requested return on Rate Base of 8.14% shown on Exhibit 400 using the HTY data.

IV. HTY – Exhibit 4 - Operation & Maintenance Expenses

Q. What are Columbia's per books historic test year O&M Expenses?

A. In the HTY, Columbia recorded $157,859,589 in O&M expense exclusive of gas cost, as shown on Exhibit 4, Schedule 1, Page 2, Column 1. The O&M data is presented in a Cost Element format which provides a breakdown by cost causation.

Q. Did you make adjustments to the actual HTY O&M to reflect a pro forma HTY O&M expense level?

A. Yes. I have prepared pro forma O&M expenses for this filing. The historic test year level of O&M expense starts with O&M Expense per books, which was then normalized and annualized to determine the pro forma level of O&M Expense as summarized on Exhibit 4, Schedule 1, Page 2 and Column 5.

Q. What types of adjustments are you proposing to the O&M expense?

A. I propose the following ratemaking adjustments to the HTY, each of which will be explained in greater detail later on in my testimony:

a) The removal of Rate Case expense related to the Company's prior base rate proceeding;

b) The removal of all Polypipe related expenses and credits to expense;

c) Labor related adjustments to annualize normal payroll for employees as of the end of the HTY;

d) Incentive compensation has been adjusted;

e) Removal of the negative OPEB expense;

f) Annualization of building rents and leases;

g) Corporate insurance adjusted to latest known and measurable levels;

h) Injuries and Damages adjusted to reflect a five year average of cash payments;

i) Company Memberships adjusted to latest known and measurable level;

j) Removal of fuel used in company operations;

k) Advertising adjusted to remove non-recoverable items;

l) Adjust Commission fees to latest known and measurable level;

m) NiSource Corporate Services costs adjusted to annualize labor and incentive costs and remove non-recoverable items;

n) Adjust deferred OPEB refund amortization to reflect the annualized level;

o) Adjust NCSC OPEB amortization level to reflect the annualized level;

p) Remove NiFiT expenses which are included in the NiFiT amortization;

q) Adjust NiFiT amortization to reflect the annualized level;

r) Removal of lobbying expenses;

s) Removal of Charitable Contributions;

t) Normalization of rate case expense;

u) Adjust Uncollectible expense;

v) Adjust USP Rider expense to match revenue; and

w) Interest on customer deposits.

A. <u>Rate Case Expense Removal</u>

Exhibit 4: *Schedule 1, Page 2, Column 2; Schedule 2, Page 1.*

Q. Please provide a brief explanation of the adjustment to remove rate case expense.

A. The HTY included actual rate case expenses related to the Company's prior base rate proceeding, Docket No. R-2014-2406274. These expenses are removed, as rate case expense is included at a normalized level in Schedule 1, Page 2, Line 27 which

is explained later in my testimony. The removal of these prior rate case costs is detailed in Column 2 as they impact several Cost Elements of O&M expense.

B. Removal of Polypipe

Exhibit 4: *Schedule, 1 Page 2, Column 3; Schedule 2, Page 2.*

Q. Please provide a brief explanation of the Polypipe adjustment.

A. In December 2012, the Company reached an agreement with a supplier of plastic pipe that had a manufacturing abnormality that reduced its intended service life. According to this agreement, the supplier will reimburse the Company for any costs associated with the remediation efforts. Both costs and reimbursement credits to expense should be removed from the Cost of Service for ratemaking purposes. This ratemaking practice is consistent with the removal of Polypipe related costs and reimbursement credits in Columbia's last two base rate cases. Since the HTY includes both remediation costs and credits to reimburse the Company for these costs, it is appropriate to remove both. This adjustment impacts two lines of O&M expense, which is why the removal of Polypipe is detailed in Column 3 on Exhibit 4, Schedule 1.

C. Labor

Exhibit 4: *Schedule 1, Page 2, Line 1; Schedule 2, Pages 3, 4 and 5.*

Q. Please provide a brief explanation of the labor adjustments.

A. Labor costs in the historic test year were adjusted to reflect the annualized gross base or normal wages of the 580 active Columbia employees as of November 2014. The difference, or annualization adjustment, was further adjusted to net O&M Expense by applying the labor capitalization ratio as provided on Exhibit No. 4, Schedule 2, Page 7. The resulting adjustment of $1,119,411 as calculated in Schedule 2, Page 3 is being added to the actual HTY labor expense level of $25,550,026 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $26,669,437 as shown on Exhibit 4, Schedule 1, Page 2.

D. Incentive Compensation

Exhibit 4: *Schedule 1, Page 2, Line 2; Schedule 2, Page 6*

Q. Please provide an explanation of the historic test year incentive adjustment.

A. Columbia's historic test year per books incentive level of $1,963,563 was decreased by $254,672 to reflect the actual level of expense associated with incentive compensation paid in 2014. This adjustment removes any out of period true-ups for the prior year and adjusts the accrual made in the test year to the experienced pay out level at the claimed capitalization percentage. Detail supporting the historic test year adjustment is provided on Exhibit 4, Schedule 2, Page 6.

E. OPEB – Other Post Employment Benefits

Exhibit 4: *Schedule 1, Page 2, Line 4; Schedule 2, Page 8*

Q. Please describe the ratemaking adjustment for OPEB.

A. Per paragraphs Nos. 23 and 24 of the settlement agreement in the Company's last base rate case, Docket No. R-2014-2406274, the OPEB allowance in current rates is zero. Therefore, the adjustment removes the credit OPEB expense of $829,647 to reflect an adjusted expense level of $0, which matches the amount recovered in revenues. It is important to note that the OPEB credit amount is an accounting calculation, and the Company did not actually receive a credit payment.

F. Rents and Leases

Exhibit 4: *Schedule 1, Page 2, Lines 7&8; Schedule 2, Page 9*

Q. How were rents and leases adjusted for the historic test year?

A. Rents and leases were first separated into a) rents and leases related to buildings, and b) other rents and leases including communications equipment and lines, office machines and furnishings. Rents and leases attributable to contractual levels for buildings were annualized on Exhibit 4, Schedule 2, Page 9 for a total of $1,158,694. This amount was then reconciled with the per book test year level of $944,568. The resulting adjustment was $214,126. The remaining portion of rents and leases includes communications equipment and lines, office machines, and other items. The historic test year level related to these is $686,635 and remains unchanged.

G. Corporate Insurance

Exhibit 4: *Schedule 1, Page 2, Line 9; Schedule 2, Page 10*

Q. Please explain the Corporate Insurance adjustment for the historic test year.

A. Corporate insurance includes property insurance premiums, workers compensation premiums, and other miscellaneous premiums. The premium policies are primarily on a fiscal year ending June of each year. The historic adjustment annualizes at the monthly November 2014 premium level which mostly reflects premiums paid in mid-2014 with effective periods of July 1, 2014 to June 30, 2015. Detailed support for these adjustments has been provided on Exhibit 4, Schedule 2, Page 10.

H. Injuries and Damages

Exhibit 4: *Schedule 1, Page 2, Line 10; Schedule 2, Page 11*

Q. Was an adjustment made for injuries and damages?

A. Yes. The historic test year expense level for injury and damages of $413,698 represents an amount including both actual experience and adjustments to an injury and damages accrual account. An adjustment of $89,293 was made to represent a five (5) year average actual cash outlay experience in real dollars using a Gross Domestic Product ("GDP") Deflator. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 11.

I. Company Memberships

Exhibit 4: *Schedule 1, Page 2, Line 12; Schedule 2, Page 12*

Q. Please explain the adjustments made for Company memberships.

A. The historic test year expense for company memberships has been adjusted for two items. The adjustment of $862 was made to remove expenses that were

inadvertently included. The details of these adjustments are shown on Exhibit 4, Schedule 2, Page 12.

J. Utilities and Fuel Used in Company Operations

Exhibit 4: *Schedule 1, Page 2, Line 13; Schedule 2, Page 13*

Q. What does the historic test year $422,985 adjustment for Utilities and Fuel used in Company Operations represent?

A. This $422,985 decrease to total historic test year utilities and fuel used in company operations was made to recognize inclusion of this amount as both recovery of gas cost and gas purchase expense by witness Lai. Columbia includes the expenses associated with gas used in company operations when establishing its gas cost recovery rates. The purchased gas is recorded as system supply and then reclassified from gas purchase to O&M expense. Therefore, it is necessary to remove the amount above from O&M for the purposes of calculating base rates and appropriately show this same level of expense in gas purchase expense along with an offsetting gas recovery level. The remaining historic test year level of $800,909 represents other utility costs, such as electric, not recovered through the 1307(f) process.

K. Advertising

Exhibit 4: *Schedule 1, Page 2, Line 14; Schedule 2, Page 14*

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to remove the expense associated with its brand advertising campaigns. Please see Exhibit 4, Schedule 2, page 14 for details.

L. Commission, OCA, OSBA Assessments

Exhibit 4: *Schedule 1, Page 2, Line 18; Schedule 2, Page 15*

Q. Please explain the $333,405 adjustment to the historic test year expense.

A. The adjustment is needed to increase the historic test year expense to the most current invoice amount for Commission, Office of Consumer Advocate and Office of Small Business Advocate assessments. The normalized test year expense amount of $2,100,840 reflects the most recent invoice amount (September 23, 2014) received as of the submission of this base rate filing.

M. NiSource Corporate Services Company ("NCSC")

Exhibit 4: *Schedule 1, page 2, Lines 19 & 20; Schedule 2, pages 16-23*

Q. Please explain the structure and role of NCSC.

A. NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource corporate organization. NCSC provides a range of services to the individual operating companies within NiSource, including Columbia, and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors. NCSC was established to provide centralized services economically and efficiently. The rendering of services on a centralized basis enables Columbia to realize substantial

economic and other benefits including efficient use of personnel and equipment, and the availability of personnel with specialized areas of expertise.

Q. Is there a contract between Columbia and NCSC?

A. Yes. A copy of the most recent Service Agreement between NCSC and Columbia was filed with the Commission and approved by Order dated December 15, 2005. A copy of the Service Agreement ("2005 Agreement") is provided as Exhibit 4, Schedule 11, Attachment H. Other detailed information regarding NCSC is also provided as a part of Exhibit 4, Schedule 11.

Q. How are NCSC's costs billed to affiliates?

A. There are two types of billings made to affiliates, including Columbia: 1) contract billing; and 2) convenience billing. Contract billings are identified by job order and represent labor and expenses billed to the respective affiliate. Contract billed charges may be direct (billed directly to a single affiliate) or allocated (split between or among several affiliates), depending on the nature of the expense. Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services.

Q. How does NCSC determine charges applicable to Columbia?

A. NCSC was regulated by the SEC under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to FERC. Pursuant to FERC Order No. 684, issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with PUHCA 2005 and FERC, NCSC uses a job order system to collect costs that are applicable and billable to affiliates, including Columbia. A job order assigns a 10-digit number to the project(s) involved and details how expenses are to be charged for the project(s). This is the same job order system that has been used by NCSC for many years. Specific projects undertaken by an affiliate are assigned by that affiliate to an existing job order or a new job order is created. Costs are recommended to be directly charged to a particular affiliate whenever possible. Some job orders necessarily involve more than one affiliate, and in that case, the job order details how expenses are allocated among participating affiliates.

Q. Please explain how costs assigned to a particular job order are allocated.

A. Allocations among affiliates are made only if it is impractical or inappropriate to charge an affiliate directly. Whenever a new job order is created, a decision is made

cooperatively by the operating company and NCSC personnel about how costs assigned to that job order will be allocated among participating affiliates. Costs are then assigned using one of the Bases of Allocation or direct company codes. Unless a change occurs in the identity of the affiliates participating in a specific job order, costs that are assigned to the job order will be consistently billed by NCSC to its affiliates from that point forward because the job order Bases of Allocation remain the same over time.

Q. Please describe the controls in place to ensure that an affiliate is consistently and appropriately billed for a specific job order.

A. The job orders are maintained by the NCSC Accounting Department and, therefore, only a few individuals within NCSC Accounting can create or modify job orders. Each job order can be set up with only one Basis of Allocation and, in many cases, only one specific allocation code or direct company billing is set up for a particular job order, depending on which affiliate(s) benefit from the services. If an individual would attempt to use a different Basis of Allocation with a job order that was not selected at inception, the related accounting systems would prompt an immediate error and not allow data to be input. Allocation Bases are defined in the Service Agreements.

Q. Will NiFiT impact the accounting system used by NCSC?

A. Yes. Effective April 1, 2015, a new accounting system will be in place for NCSC as a part of the overall NiFiT project. The underlying functionality will remain the same; however, the mechanics of the accounting system will be updated.

Q. Has the FERC conducted an audit of NCSC, its billing system and allocation methodologies?

A. Yes. NiSource Inc., including NCSC, underwent a FERC audit, Docket No. FA11-5-000, which covered the period January 1, 2009, through December 31, 2010. The Final Audit Report was issued by the FERC on October 24, 2012. As indicated in the Final Report, the Audit Staff reviewed and tested the supporting details for NCSC's cost allocation methods. They then sampled and selected supporting documents to ensure that NCSC's billings and accounting comply within the USOA (Uniform System of Accounts). FERC did not issue any adverse comments to NCSC related to its allocation methods.

Q. Has the Company changed the way it is presenting the costs associated with NCSC?

A. Yes. The Company has decided to breakout the costs associated with NCSC into two distinct categories: Shared Services and Shared NGD Operations.

Q. Why has the Company decided to provide this breakout?

A. The Company has decided to provide this breakout in order to provide an additional level of detail that recognizes that NCSC has two major categories of services that are provided to the Operating Companies at NiSource.

Q. Please explain NCSC – Shared Services.

A. The first category of Shared Services includes costs associated with the more traditional services that are provided by a service company, such as Accounting and Finance, Legal Services, Real Estate and Facilities, Information Technology, Human Resources and Supply Chain.

Q. Please explain NCSC – Shared NGD Operations.

A. The second category of Shared NGD Operations includes costs that are typically operational in nature or specialized, but because these groups serve all of NiSource's Gas Distribution companies, they are now a part of NCSC. These groups provide services such as Engineering, Pipeline Safety & Compliance, Technical Training, Rates and Regulatory Support, Call Center, Sales and Marketing, Gas Control etc.

Q. Are you sponsoring the adjustments made on Exhibit 4, Schedule 1, Page 2 to NCSC – Shared Services?

A. Yes. The following adjustments have been made to NCSC - Shared Services charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 16:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2014;

b) Annualization of Labor, Payroll Taxes & Benefits;

c) Removal of "Phantom Stock";

d) Removal of Non-recoverable Items and Non-recurring Items.

Q. Please provide a brief overview of Page 16.

A. Page 16, line 1 states the gross NCSC – Shared Services charges in the HTY. A portion of these costs are recorded to non-O&M accounts (primarily capitalized in Account 107 Construction Work in Progress for support of the infrastructure investments). Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC – Shared Services billings is $31,221,141.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 16, Lines 4 through 15 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC – Shared Services Incentive Compensation to the level paid in 2014 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 17.

Line 5 - Annualizes gross NCSC – Shared Services labor, payroll taxes and benefits as detailed on Page 18, net NCSC – Shared Services labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC – Shared Services labor charged to O&M and derived on Exhibit 4 Schedule 2 Page 17 Line 14.

Lines 7 – 12 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Line 13 – Non-recurring items that were included in the HTY are removed from the pro forma HTY expense claim.

Q. Are you sponsoring the adjustments made on Exhibit 4, Schedule 1, Page 2 to NCSC – Shared NGD Operations?

A. Yes. The following adjustments have been made to NCSC – Shared NGD Operations charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 20:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2014;

b) Annualization of Labor, Payroll Taxes & Benefits;

c) Removal of Non-recoverable Items and Non-recurring Items.

Q. Please provide a brief overview of Page 20.

A. Page 20, line 1 states the gross NCSC – NGD Shared Operations charges in the HTY. A portion of these costs are recorded to non-O&M accounts (primarily capitalized in Account 107 Construction Work in Progress for support of the infrastructure investments). Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC – NGD Shared Operations billings is $18,915,049.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 20, Lines 4 through 14 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC – NGD Shared Operations Incentive Compensation to the level paid in 2014 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 21.

Line 5 - Annualizes gross NCSC – NGD Shared Operations labor, payroll taxes and benefits as detailed on Page 22, net NCSC – NGD Shared Operations labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC – NGD Shared Operations labor charged to O&M and derived on Exhibit 4 Schedule 2 Page 21 Line 14.

Lines 6 – 11 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Line 12 – Non-recurring items that were included in the HTY are removed from the pro forma HTY expense claim.

N. Deferred OPEB Refund Amortization

Exhibit 4: *Schedule 1. Page 2, Line 21; Schedule 2, Page 24*

Q. Has the HTY been adjusted to reflect the appropriate amount of deferred OPEB refund amortization?

A. Yes. According to the Settlement in the Company's prior base rate proceeding, Docket No. R-2012-2321748, the Company was to reflect a two year amortization of pre-July 1 deferred OPEB amounts totaling $607,393, or $303,697 annually. The details of this adjustment are found on Exhibit 4, Schedule 2, Page 24. Note that the

FTY reflects an 18 month amortization period starting January 1, 2015 according to the Settlement in the Company's 2014 rate case, Docket No. R-2014-2406274.

O. NCSC OPEB Amortization

Exhibit 4: *Schedule 1, Page 2, Line 20; Schedule 2, Page 20*

Q. Has the HTY been adjusted to reflect the appropriate amount of NCSC OPEB amortization?

A. Yes. According to the Settlement in the Company's prior base rate proceeding, Docket No. R-2014-2406274, the Company is permitted to amortize the regulatory asset of $903,131 associated with the transition of NCSC from a cash to accrual basis for OPEBs, over a ten year period, or $90,313 annually. Exhibit 4, Schedule 2, Page 25 shows that no adjustment is required as the HTY correctly reflects the annualized level of amortization expense of $90,313.

P. NiFiT Expense

Exhibit 4: *Schedule 1, Page 2, Line 23; Schedule 2, Page 26*

Q. Please explain the adjustment to NiFiT Expense.

A. Per the Settlement approved at Docket No. R-2012-2321748, Columbia was allowed amortization recovery of the estimated non-labor NiFiT expenses over a four year period. Upon approval of the settlement by the Commission, Columbia reversed all non-labor NiFiT expenses to date and recorded a regulatory asset. In January 2014, Columbia reached the maximum amount of the allowed deferral according to the

Settlement; all further billings of this nature were expensed. Per the Settlement approved in Docket No. R-2014-2406274, the total amount of estimated non-labor expenses that could be deferred and amortized was increased. Exhibit 4, Schedule 2, Page 26 identifies the amount of non-labor NiFiT expense that needs to be deferred for (and removed from) the HTY.

Q. <u>NiFiT Amortization</u>

Exhibit 4: *Schedule 1, Page 2, Line 24; Schedule 2, Page 27*

Q. Please explain the NiFiT Amortization adjustment.

A. According to the Settlement in the Company's prior base rate proceeding, Docket No. R-2014-2406274, the Company is permitted to defer and amortize over a five year period, non-company labor start-up costs of the new financial software of $2,029,202, which was the estimated remaining level of non-labor expense. NiFiT Amortization has been adjusted to this new level of $405,840. Please see Exhibit 4, Schedule 2, Page 27 for the details of this adjustment.

R. <u>Lobbying Expense</u>

Exhibit 4: *Schedule 1, Page 2, Line 25; Schedule 2, Page 28*

Q. Please describe the lobbying expense adjustment.

A. An adjustment has been made for the removal of lobbying expenses related to labor as well as other O&M cost drivers. As such, this adjustment has not been categorized by cost driver but instead is shown as a stand-alone line item on Exhibit

4, Schedule 1, Page 2, Line 25. Detail for this adjustment is provided on Exhibit 4, Schedule 2, Page 28.

S. Charitable Contributions

Exhibit 4: *Schedule 1, Page 2, Line 26; Schedule 2, Page 29*

Q. How were charitable contributions treated as a cost of service item?

A. Charitable contributions are normally booked below the line in a non-utility account and are not a part of Columbia's claim as a cost of service item. Please see Exhibit 4, Schedule 2, page 29 for the details of removing any contributions that were inadvertently booked above the line.

T. Rate Case Expense Normalization

Exhibit 4: *Schedule 1, Page 2, Line 27; Schedule 2, Page 30*

Q. Has the Company included a normalized level of rate case expense in its HTY Cost of Service?

A. Yes. The approved rates from the Company's last rate case include an amount for recovery of rate case expenses. As explained previously, actual rate case expense from the Company's prior rate case has been removed from pro forma HTY expense. I have included a normalized level of rate case expense based on the proposed rate case expense normalization included in this current case as determined on Exhibit 104, Schedule 2, and Page 21.

U. Uncollectible Accounts Expense

Q. Please explain Columbia's claim for recovery of uncollectible accounts expense.

A. Two major categories of uncollectible accounts have been recorded historically and have been represented in the development of cost of service support. These two categories are "normal" (or non-CAP) uncollectible accounts and Customer Assistance Program ("CAP") uncollectible accounts.

Normal uncollectible accounts expense has been developed on Exhibit 4, Schedule 2, Page 31 for the historic test year. The CAP uncollectible accounts expense has been developed on Exhibit 4, Schedule 2, Page 33 for the historic test year.

V. Normal Uncollectible Accounts

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 4: *Schedule 1, Page 2, Line 28 & 29; Schedule 2, Pages 31 – 33*

Q. Please explain the development of the historic test year normal uncollectible accounts expense.

A. Exhibit 4, Schedule 2, pages 31 through 33 set forth the development of a percentage for uncollectible accounts related to normal charge offs recovered through base rates. The schedules also calculate a three year average write off for large volume customers.

The write off percentage for charge offs related to normal customers recovered through base rates is calculated based on comparing the three-year average of write-offs for normal uncollectible accounts expense to billed revenue. Several

adjustments to billed revenue are necessary to develop the write off percentage. First, account write-offs lag billed revenue by approximately 120 days or 4 months. This lag in days includes consideration for the time between original billing and an account being placed into final status, as well as consideration for the average time between an account being placed into final status and termination of service, which is when the account is written-off. I have used billed revenue for the twelve months ended July of each year to appropriately reflect the lag (4 months) between the billing and write-off of accounts.

Additionally, I have provided on Page 32, the average write-off rate for Residential customers as well as the combined write-off rate for Commercial and Industrial customers. This information was utilized by Company witness Lai in the development of the Merchant Function Charge.

Q. What other adjustments have been made to billed revenue?

A. Columbia's Distributive Information System ("DIS") billing system is used to bill all residential and small business accounts and, therefore, includes revenues applicable to CAP customer accounts. Line 2 of Page 31, titled as, "Total DIS Billed Revenue," has been adjusted to remove the revenue associated with Columbia's CAP (Page 31, Line 3), as CAP uncollectibles are accounted for separately. Line 4 of Page 31 represents Adjusted DIS Billed Revenue that relates to the net write-offs as shown on Line 9 of Page 31.

Q. How were the net write-offs shown on Line 9 developed?

A. The net write-offs shown on Line 9 of Page 31 represent the summation of gross charge-offs and recoveries for all customers billed through DIS.

Q. How are the adjusted billed revenue and net write-off amounts used in the development of normal uncollectibles?

A. The three years of adjusted revenue is added together to generate the total revenue as shown on Line 4. Similarly, a three year total is developed for net write-offs. An uncollectible rate is then calculated by dividing the total net write-off by the total adjusted revenue. This rate, which is shown on line 10, is then applied to the annualized DIS revenue as provided by witness Lai for the historic test year. The result is Columbia's adjusted historic test year normal uncollectibles for DIS billed customers, line 16.

Q. Does this fully describe all adjustments made to the historic test year normal uncollectible expense?

A. No. DIS is one of three billing systems used to bill revenue related to normal uncollectible write-offs. The other billing systems, the Gas Transportation System ("GTS") and Gas Measurement Billing ("GMB"), are used to bill larger customers including chart read customers, daily read customers, customers with multiple rate components, and non-CHOICE transportation customers. A three year average net write-off was developed for uncollectible accounts related to these larger customers. Columbia did not include these write-off amounts in the calculation of a net write-off rate, as was done for DIS billed accounts, because larger customer write-offs

occur infrequently, but can produce disproportionate write-off amounts when they do occur, as can be seen in the three-year experience write offs for this type of customer.

Q. Please summarize Columbia's proposed normal historic test year uncollectible accounts expense adjustments.

A. The historic normal uncollectible adjustment is a decrease to expense of $335,673 as shown on Exhibit 4, Schedule 1, Page 2, Lines 28 and 29. This amount has been developed by comparing an annualized DIS, GTS, and GMB net write-off as described above and comparing that to the normal uncollectible expense level as recorded in Columbia's test year ending November 30, 2014.

W. Rider USP Costs

(Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

Exhibit 4: *Schedule 1, Page 2, Line 30; Schedule 2, Page 34*

Q. Are you sponsoring an adjustment for Rider USP costs as well?

A. Yes. Rider USP adjustments have been made to the historic test year as shown on Exhibit 4, Schedule 2, Page 34.

Q. Please explain the test year adjustments.

A. The adjustments are a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 3, Page 10, Rider USP revenues are $28,799,344 for the normalized historic test year. Consequently, the various adjustments reflect changes that are necessary to match the expense with

the revenues as determined by Company witness Lai. As a result, the Rider USP net impact to operating income is zero with the expense offsetting revenues. Therefore, Rider USP costs do not impact the base rate increase requested in this case.

X. Interest on Customer Deposits

Exhibit 4: *Schedule 1, Page 2, Line 31; Schedule 2, Page 31*

Q. Please explain the adjustment for Interest on Customer Deposits.

A. An adjustment for interest on customer deposits is necessary to recognize the expense related to interest recorded on customer deposits not included in Operation and Maintenance Expense on the books and records of Columbia. Customer deposits are considered a source of capital in Columbia's rate base for this case and, as such, reduce rate base. This adjustment is made to recognize the expense related to this source of capital. The adjustment reflects the 3% interest rate on customer deposits established under Chapter 14 of the Public Utility Code applied to the average customer deposit balance. No further adjustment is made to this item for either the future test year or the fully forecasted rate year, because the Company has made no projection of changes to the balance of customer deposits.

V. FTY/FFRY – Exhibit 102 – Statement of Income

Q. Is Exhibit 102 presented in the same format as Exhibit 2?

A. Yes. Exhibit 102, Schedule 3 is a Statement of Income based on FTY, FFRY and Proposed Rates. Exhibit 102, Schedule 3, Page 3 as referenced earlier in my testimony when describing Exhibit 2, Schedule 3, Page 3, utilizes data that has been

provided by other witnesses in this case to determine a revenue requirement. This Exhibit begins with the FTY at present rates in Column 2 and the FFRY in Column 4. Adjustments in Column 5 are then made to determine the FFRY at proposed rates in Column 6. Column 5 shows the revenue requirement of $46,172,483 necessary to achieve a reasonable opportunity to earn a fair rate of return. The various exhibits in support of the adjustments at present and proposed rates are identified in Columns 1 and 3.

Q. Please explain Exhibit 102, Schedule 3, Page 4.

A. This page calculates synchronized interest expense based upon the FTY rate base multiplied by the weighted cost of debt in Lines 1 through 4 and similarly based on the FFRY year rate base multiplied by the weighted cost of debt in Lines 5 through 8.

Q. Please explain Page 5 of Exhibit 102, Schedule 3.

A. This page presents the calculation of the required revenue increase of $46,172,483 using the revenue conversion factor. The revenue conversion factor accounts for additional normal uncollectible expense of $602,992 generated by Columbia's requested increase in revenues as calculated on page 6 of Exhibit 102 as well as additional Late Payments Fees of $113,901, which is calculated by first determining an experience rate of Late Payments Fees at Present Rates. This is done by dividing the amount of total Late Payment Fees on Exhibit 102, Schedule 3, Page 3, Column 4, Line 11 by Total Sales and Transportation Revenues on Exhibit 102, Schedule 3,

Page 3, Column 4, Line 9. This experience factor is then applied to the Additional Revenue Requirement on Line 1 of Exhibit 102, Schedule 3, Page 6 to determine the additional Late Payment Fees.

The effective State Income Tax rate has been recalculated and reflects differences in the tax net operating loss positions.

VI. FTY/FFRY – Exhibit 104 – Operations and Maintenance Expense

Q. Did you utilize a budget-based methodology to determine O&M Expense for the FTY and the FFRY as Columbia has done in the prior base rate proceeding?

A. Yes. The future test year and fully forecasted rate year levels of O&M expense begin with the budget as supplied and supported by Company witness Hanson (Columbia Statement No. 9). A month by month presentation can be found on Exhibit 104, Schedule 1, Pages 5 and 6. Ratemaking adjustments have been made to normalize and annualize the budget to arrive at Pro Forma O&M Expenses.

Q. Have you made modifications to the Exhibit 104 as directed by settlement paragraph 37 of Docket No. R-2014-2406274, which states:

> In all future base rate cases, whether the Company uses a "build-up" or "budget-based" filing format, the schedules for O&M as detailed on Columbia Exhibit No. 104 shall display differences between the pro forma Historic Test Year ("HTY") and Future Test Year ("FTY") amounts, as well as the differences between the FTY and FPFTY amounts.

A. Yes. Exhibit 104, Schedule 1 has been expanded to a total of six pages and provides a clear distinction between "Budget Adjustments" and "Ratemaking Adjustments"

for both the FTY and the FFRY. Company witness Hanson is supporting all budget adjustments, while I am supporting all ratemaking adjustments.

Q. Please provide a brief description of each of the 6 pages of Exhibit 104, Schedule 1.

A. Page 1 references pages 2 – 6 of the Exhibit.

Page 2 is the summary view of Operations and Maintenance Expense for all test years in this case. Column 1 presents the Normalized HTY, Column 3 presents the Normalized FTY and Column 5 presents the Normalized FFRY. Columns 2 and 4 provide both the budget adjustments and the rate making adjustments that adjust the HTY to the FTY and the FTY to the FFRY.

Pages 3 and 4 are formatted in a similar manner. Page 3 contains details for the FTY; while page 4 contains the details for the FFRY. Page 3 starts with the Normalized HTY in column 1, followed by the Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized HTY to the Budgeted FTY (Column 4) which is supported by Company witness Hanson. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FTY (Column 7). Similarly, Page 4 provides the details for the FFRY, starting with the Normalized FTY (Column 1; from page 3) followed by the Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized FTY to the Budgeted FFRY (Column 4) which is also supported by Company witness Hanson. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FFRY (Column 7).

Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FFRY (Page 6); supported by witness Hanson.

Q. Did you utilize the O&M budget for all the O&M items on Exhibit No. 104?

A. No. Lines 1 through 24 on Exhibit No. 104, Schedule No. 1, Column 4, Pages 3 and 4 reflect the O&M budget data used in the FTY and FFRY periods. The O&M budget data was not utilized for the cost items noted on Lines 26 through 31 of these same pages. These items include:

- Line 26 – Rate Case Expense – the amounts reflect normalized costs associated with the current case that should be included in the revenue requirement in this case.
- Lines 27– Uncollectible Accounts – the uncollectible expense is reflective of the standard practice of using a 3 year average of charge-off experience of FTY and FFRY revenues as provided by Company witness Lai.
- Lines 28 & 29 – Uncollectible Accounts – Unbundled & Total Rider USP – the amounts are adjusted to reflect the amounts included in revenues as provided by Company witness Lai.
- Line 30 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 31 – Other Adjustments – these items were not identified in time to be included in the O&M budget that was used as the starting point for the FFRY period.

Q. What types of adjustments are you proposing to O&M expense for the FTY and FFRY?

A. I propose the following ratemaking adjustments to determine Pro Forma O&M Expense for the FTY and FFRY, which will be explained in detail later on in my testimony:

a) Annualization of Company Labor;

b) Adjust Pension expense to reflect a two year average of cash contributions;

c) Removal of the negative OPEB expense;

d) Adjustment to remove Polypipe credit;

e) Annualization of building rents and leases;

f) Injuries and Damages adjusted to reflect HTY plus inflation;

g) Removal of fuel used in company operations;

h) Advertising adjusted to a normalized level of recoverable expense;

i) NCSC costs adjusted to annualize labor and remove non-recoverable items;

j) Adjust deferred OPEB refund amortization to reflect the annualized level;

k) Remove NiFiT expenses which are included in the NiFiT amortization;

l) Adjust NiFiT amortization to reflect the annualized level;

m) Removal of lobbying expenses;

n) Normalization of rate case expense;

o) Adjust Uncollectible expense;

p) Adjust Rider USP expense to match revenue;

q) Other Adjustments to the FFRY.

A. Labor

Exhibit 104: *Schedule 1, Page 2, Line 1; Schedule 2, Pages 1*

Q. Please provide a brief explanation of the labor adjustments.

A. Columbia has determined annualization adjustments for the FTY of $328,201 and for the FFRY of $297,299. These adjustments are for normal pay increases only and reflect an O&M percentage of 57.21% which is the same percentage as used in the Budget for items that have been adjusted from gross amounts to net O&M expense.

B. Pension Expense

Exhibit 104: *Schedule 1, Page 2, Line 3; Schedule 2, Page 2*

Q. What is the basis for the Company's qualified Pension claim?

A. The Company's claim for the qualified pension expense is based on Pension Contributions made by the Company to the Pension trust. Specifically, the gross claim is based on a two year average of the gross Pension contributions. These gross amounts are then adjusted to expense based on the O&M percentage rate.

Q. Please explain the calculation of the future test year qualified pension adjustment.

A. Columbia's future test year expense was adjusted to reflect the average annual contributions using a 2-year average ending November 30, 2015 – Exhibit No. 104, Schedule No. 2, Page 2, Line 5. Further, Line 7 calculates the net portion charged to

O&M. An adjustment is determined when compared to the amount included in the budget, Line 8. Included in the 2-year average are projected pension contributions as provided by AON Hewitt and provided on Exhibit 104, Schedule 2, Page 3.

Q. Please explain the calculation of the fully forecasted rate year qualified pension adjustment.

A. Columbia's fully forecasted rate year expense was adjusted to reflect the average annual contributions using a 2 year average ending December 31, 2016 – Exhibit No. 104, Schedule No. 2, Page 2, Line 14. Further, Line 16 calculates the net portion charged to O&M. An adjustment is determined when compared to the amount included in the budget, Line 17. Included in the 2 year average are projected pension contributions as provided by AON Hewitt and provided on Exhibit 104, Schedule 2, Page 3.

C. OPEB – Other Post Employment Benefits

Exhibit 104: *Schedule 1, Page 2, Line 4; Schedule 2, Page 4*

Q. Please explain the ratemaking for OPEB Expense as approved in the Company's last rate case.

A. Provision Nos. 23 and 24 of the settlement agreement of the Company's last base rate case address this subject by stating:

> 23. As established in the settlement of Columbia's base rate proceeding at R-2012-2321748, Columbia will be permitted to continue to defer the difference between the

> annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded reflects a regulatory asset, such amount will be collected from customers in the next rate proceeding over a period to be determined in that rate proceeding. To the extent the cumulative balance recorded reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense, and the cumulative balance will continue to be maintained.
>
> 24. Commencing with the effective date of rates, Columbia will deposit amounts in the OPEB trusts when the cumulative gross annual accruals calculated by its actuary pursuant to ASC 715 are greater than $0. If annual amounts deposited into OPEB trusts, pursuant to this Settlement, exceed allowable income tax deduction limits, any income taxes paid will be recorded as negative deferred income taxes, to be added to rate base in future proceedings.

Q. Is the Company proposing a change to these provisions?

A. No. The cumulative OPEB expense at the end of the HTY is less than zero and the expected on-going OPEB expense continues to reflect credit expense. Therefore, the Company proposes to continue using this ratemaking treatment for OPEB expense.

Q. Do the ratemaking adjustments for OPEB Expense as presented on Exhibit 104, Schedule 2, Page 4 comply with the provisions as listed above?

A. Yes, the FTY and FFRY adjustments remove from the budgets the credit OPEB expense of $780,000 and $853,000, respectively to reflect an adjusted expense level of $0. I emphasize that these credit amounts are not projected cash receipts, but just accounting credits.

D. Outside Services - Polypipe Adjustment

Exhibit 104: *Schedule 1, Page 2, Line 6; Schedule 2, Page 5*

Q. Were outside service expenses adjusted for ratemaking?

A. Yes. As explained earlier in this testimony, all costs and reimbursements related to the Polypipe issue should be removed for ratemaking purposes. The budget for the FTY includes a Polypipe credit to expense which has been removed in the amount of $551,000. The FFRY O&M budget has no costs or credits related to this issue, and thus no adjustment is necessary.

E. Rents and Leases

Exhibit 104: *Schedule 1, Page 2, Line 7; Schedule 2, Page 6*

Q. Please explain the adjustment to rents and leases for the FTY and FFRY.

A. Known changes to building leases were included on Exhibit 104, Schedule 2, Page 6 resulting in an increase of $177,833 for the FTY claim and an increase of $214,395 for the FFRY claim. Please see Company witness Hanson's testimony for more detail regarding rents and leases.

F. Injuries and Damages

Exhibit 104: *Schedule 1, Page 2, Line 9; Schedule 2, Page 7*

Q. Was an adjustment made for injuries and damages?

A. Yes. The FTY and FFRY expense levels for injury and damages were adjusted to reflect the pro forma HTY claim of $413,698 plus applicable inflationary adjustments. As stated earlier in my testimony, the pro forma HTY claim reflects the average claim payments for the five years ending November, 30, 2014.

G. Utilities and Gas Used in Company Operations

Exhibit 104: *Schedule 1, Page 2, Line 12; Schedule 2, Page 8*

Q. Please explain the adjustment for Gas Used in Company Operations.

A. The FTY and FFRY O&M budget amounts include costs associated with Gas Used in Company Operations. In a manner similar to what was done in the HTY pro forma adjustments, an adjustment is also needed to eliminate these costs in the FTY and FFRY periods. The adjustments were calculated using the HTY adjustment level plus an inflationary adjustment.

H. Advertising

Exhibit 104: *Schedule 1, Page 2, Line 13; Schedule 2, Page 9*

Q. Please explain the adjustment for Advertising.

A. The FTY and FFRY O&M budget amounts are not prepared at a level that identify the specific types of advertising. The HTY advertising included a portion of non-

recoverable advertising, so for the future periods I have made adjustments to include a representative level of recoverable advertising. In a manner similar to the adjustment for Injuries and Damages, the pro forma level of HTY Recoverable Advertising was adjusted for inflation and included as the Advertising claim for the FTY and FFRY periods. This includes making significant reductions to the levels of advertising expense in the Budget for both periods.

I. NiSource Corporate Services Company "NCSC"

Exhibit 104: *Schedule 1, Page 2, Lines 18 & 19; Schedule 2, Pages 10 - 15*

Q. Are you sponsoring any ratemaking adjustments to NCSC for the FTY and FFRY?

A. Yes. In a manner similar to the HTY, NCSC Budget and Ratemaking has been broken out into two categories of Expense: NCSC – Shared Services and NCSC – Shared NGD Operations. Exhibit 104, Schedule 2, Page 10 summarizes the ratemaking adjustments to NCSC – Shared Services for the FTY and FFRY; ratemaking adjustments for NCSC – Shared NGD Operations are summarized on page 13. Note that on Page 10 the Budgeted amounts for "Phantom Stock" have been removed from NCSC – Shared Services. NCSC – Shared NGD Operations Budgeted amounts do not include any claims for "Phantom Stock."

I have made adjustments to annualize labor and to remove non-recoverable items for both future periods. Pages 11 and 14 provide the details for the determination of adjustments to annualize labor; the annualization is similar to the HTY adjustment in that I am using the last month of the test period as the basis for the

annualization. Since these adjustments were based upon gross amounts, I have utilized the HTY percentages of NCSC Charges to Labor to determine the net adjustments for both periods.

Pages 12 and 15 determine the adjustments for the removal of non-recoverable items. These adjustments are based upon the HTY level of expense, plus incremental adjustments that are produced by using inflation factors.

J. OPEB Deferral Passback Amortization Adjustment

Exhibit 104: *Schedule 1, Page 2, Line 20; Schedule 2, Page 16*

Q. Please explain the level of OPEB Deferral Passback Amortization in the FTY claim.

A. The FTY amortization has been adjusted to reflect the actual amortization as stated in the settlement agreement in the last base rate case, Docket No. R-2014-2406274.

Q. Please explain the level of OPEB Deferred Passback Amortization in the FFRY claim.

A. The FFRY proposed claim is based upon an estimated OPEB deferral balance at January 1, 2016 (the commencement of the FFRY period) and a proposed amortization period of 12 months to continue the passback of these costs. The estimated January 1, 2016 balance of ($114,640) is calculated on Line 12 of Exhibit 104, Schedule 2, page 16.

K. NiFiT Expense Adjustment

Exhibit 104: *Schedule 1, Page 2, Line 22; Schedule 2, Page 17*

Q. What is included in the NiFiT Non-Labor Expense on Line 21?

A. The Company has deferred NiFiT Non-Labor expenses based on the amount stated in the Settlement of the Company's last rate case. However, $42,000 remains in expense in the FTY. I have removed the $42,000 from the FTY.

L. NiFiT Non-Labor Amortization Adjustment

Exhibit 104: *Schedule 1, Page 2, Line 23; Schedule 2, Pages 18 and 19*

Q. What is the adjustment to the FTY for NiFiT Non-Labor Amortization?

A. The FTY expense has been adjusted to reflect the actual amortization for this item as it was stated in the last rate case order; $2,029,202 over a five year period or $405,840.

Q. Does the Company propose to revise the amortization for the FFRY period?

A. Yes. The Company proposes to adjust the amortization to reflect the new estimated NiFiT Non-Labor cost of $2,318,622, which includes actual data through December 2014. The proposed annual amortization of $420,255 is calculated on Page 18 of Exhibit 104, Schedule 2 and provides for the recovery of the new estimate, less the amortization through December 2015. The Company is proposing that this new unamortized amount of $1,260,764 be amortized over three years. The three-year period is recommended as the requested annual amortization is slightly less than the annual amortization as approved in the last case.

M. Lobbying Expense

Exhibit 104: *Schedule 1, Page 2, Line 24; Schedule 2, Page 20*

Q. Please describe the lobbying expense adjustment.

A. An adjustment has been made for the removal of lobbying expenses. The FTY and FFRY adjustments are based upon the HTY level of expense adjusted for inflation.

N. Normalization – Rate Case Expenses

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 21*

Q. Has Columbia included an adjustment for rate case expense?

A. Yes. Exhibit 104, Schedule 2, Page 21 sets forth the Company's claim for rate case expenses. The estimated expenses for this rate case reflects costs to be incurred for Columbia's cost of capital witness, depreciation witness, outside counsel, and incremental costs associated with legal notices, employee expenses and duplicating. The entire rate case expense included for normalization is $1,030,000. Columbia proposes to normalize these costs over 12 months.

O. Normal Uncollectible Accounts Expense

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 27 & 28; Schedule 2, Page 22*

Q. Please explain the FTY and FFRY claim for normal uncollectible accounts expense.

A. I have utilized the Uncollectible Accounts Average Write-off Rate as developed on Exhibit 4, Schedule 2, Page 31 which represents a three year average experience of

net write-offs as a percentage of billed DIS revenues. This rate is applied to annualized FTY/FFRY DIS revenues after adjusting for CAP revenue, to arrive at Total DIS Uncollectible Accounts Expense for the FTY and FFRY.

Q. Has Columbia reflected the unbundling of uncollectibles related to gas costs?

A. Yes. Columbia has identified a portion of the normal uncollectibles that will be collected through the Merchant Function Charge.

Q. What amount is attributed to the uncollectibles related to gas costs?

A. Columbia has identified $1,752,694 in the FFRY expenses associated with the unbundling of uncollectibles related to gas costs. This amount is included in the O&M expense claim and is offset by the same amount of revenues in Exhibit 103 as developed by witness Lai. As a result, the net impact to operating income is zero and does not impact the base rate increase requested in this case. Please refer to Exhibit 104, Schedule 2, Page 22 for details.

P. Total Rider USP Costs

Exhibit 104: *Schedule 1, Page 2, Line 29; Schedule 2, Page 23*

Q. Please explain the test year adjustments.

A. The adjustments reflected in Exhibit 104 are a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 103, Rider USP revenues at present rates are $27,740,348 for the FTY and $27,644,938 for the FFRY. As a result, the Rider USP net impact to operating income is zero with the expense offsetting present rate revenues. Therefore, Rider USP costs do

not impact the base rate increase requested in this case. Ms. Lai computes the increase to Rider USP resulting from the proposed rate increase.

Q. <u>Other Adjustments to the FFRY</u>

Exhibit 104: *Schedule 1, Page 2, Line 31; Schedule 2, Page 24*

Q. Are there any other adjustments to O&M Expense that impact Columbia's claim in this case?

A. Yes, Exhibit 104, Schedule 2, Page 24 summarizes the following two additional adjustments totaling $147,648:

- Rider Customer Choice (Rider CC) Adjustment; and
- Emergency Repairs Program Adjustment.

These adjustments are being sponsored by Company witness Krajovic, and details about these adjustments can be found in her testimony.

Q. Why was a 12 month amortization / normalization period used for certain Exhibit 104 items?

A. I have utilized a 12 month amortization period for OPEB Deferral Passback Amortization and a 12 month normalization period for Rate Case Expense because the Company anticipates annual rate filings for the foreseeable future. I note that these amortization periods also align with the remaining Tax Refund Amortization as supported by Company witness Fischer.

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

MARCH 19, 2015

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated and in what capacity?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Senior Vice President.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since college graduation in June 1986.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Will you outline your experience in the field of depreciation?

A. I have over 28 years of depreciation experience which includes expert testimony in almost 200 cases before approximately 40 regulatory commissions, including the Pennsylvania Public Utility Commission ("Commission"). Please refer to Appendix A for my qualifications.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the gas plant of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Have you prepared exhibits presenting the results of your studies?

A. Yes. Exhibit No. 9 presents the results of the depreciation study as of November 30, 2014. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2015. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2016. In addition, I am responsible for the responses to the following filing requirements pertaining to depreciation under Section 53.53(a)(1) of the Commission's regulations: 3, 4, 5, 6, 7 and 17. I also sponsor Exhibit No. 5 and Exhibit No. 105, which are summaries of the results to Exhibit No. 9 and Exhibit No. 109, respectively.

Q. Please describe Exhibit Nos. 9 and 109.

A. Exhibit No. 9, Schedule No. 1, titled "2014 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2014," includes the results of the depreciation study as related to the original cost at

November 30, 2014. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2015 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2015," includes the results of the depreciation study as related to the estimated original cost at November 30, 2015. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment B, titled "2016 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2016," includes the results of the depreciation study as related to the estimated original cost at December 31, 2016.

Q. What were the purposes of your depreciation studies?

A. The purposes of the depreciation studies were to estimate the annual depreciation accruals related to gas plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve at November 30, 2015, and December 31, 2016.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation Report filed in June 2014 and service life study filed in August 2012?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used for over twenty years. For Accounts 391.1, 391.11, 391.12, 392, 393, 394, 394.5, 395, 397.1, 397.24 and 398, the claim is based on the straight line

remaining life method of amortization. The accounts have a large number of units, but small asset values representing less than 2 percent of the depreciable plant. The assets represent items located in office buildings, service centers, garages and warehouses. Given the difficulty in maintaining accounting records for these numerous assets and high cost for periodic inventories, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. All units are retired when the age of the vintage reaches the amortization period. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. The average service life procedure is used in the current proceeding for plant installed prior to 1976 and the equal life group procedure for 1976 and subsequent vintages. This calculation has been used in the same manner as the Company's most recent annual depreciation reports.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over twenty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last proceeding.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the

results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve at November 30, 2015, estimated?

A. The book reserve at November 30, 2015, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve at November 30, 2014. Annual accruals were estimated using the annual accruals calculated as of November 30, 2014. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account. For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation at November 30, 2015.

Q. Was the book reserve at December 31, 2016, estimated using the same methodology?

A. Yes.

Q. Has a service life study of the Company's gas utility property been performed?

A. Yes. The most recent service life study was performed as of December 2011. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the gas utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as distribution buildings, housing offices and shops. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant during the period 1939-2011. The year 1939 is the first year continuing property records were maintained. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves

were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its gas plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for gas utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for Columbia Gas of Pennsylvania, Inc. and for other gas companies before the Pennsylvania Public Utility Commission and that have been accepted by the Commission in its past orders concerning gas utilities.

Q. What approach did you use to estimate the lives of significant structures such as office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation

inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Pennsylvania Public Utility Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar structures. Most of the life spans result in probable retirement dates that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be analyzed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit No. 109, Schedule No. 1, Attachment A?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-4 through III-8 of Exhibit No. 109, Schedule No. 1, Attachment A.

Q. Were there any material changes to life characteristics as a result of this rate proceeding?

A. No. There was no material change in the life estimate for plant accounts or subaccounts in this rate proceeding. All life estimates were based on the recent annual depreciation reports when the service life studies were conducted.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment A.

A. Exhibit No. 109, Schedule No. 1, Attachment A is presented in eight parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account. Part VIII, Experienced and Estimated Net Salvage, presents the cost of removal and gross salvage by account for the years 2010 through 2014.

Table 1, pages V-4 through V-6, presents the estimated survivor curve, the original cost at November 30, 2015, and the book reserve and calculated annual depreciation for each account or subaccount of Gas Plant. Table 2,

pages V-7 and V-8, presents the bringforward to November 30, 2015, of the book depreciation reserve as of November 30, 2014. Table 3 on pages V-9 and V-10 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-11, presents the experienced and estimated net salvage during the five-year period, 2010 through 2014.

The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-1 presents the depreciation calculations related to original cost. The tabulation on pages VII-3 through VII-6 presents the cumulative depreciated original cost by year installed. The tabulations on pages VII-8 through VII-73 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment B.

A. Exhibit No. 109, Schedule No. 1, Attachment B includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2016. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 109, Schedule No. 1, Attachment B. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the service life estimates used in Exhibit No. 109, Schedule No. 1, Attachment B inasmuch as the estimates are the same for both test years. The summary tables

and detailed depreciation calculations as of December 31, 2016, are organized and presented in the same manner as those as of November 30, 2015.

Q. Please outline the contents of Exhibit No. 9.

A. Exhibit No. 9 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of November 30, 2014. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 9. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the service life estimates used in Exhibit No. 9, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of November 30, 2014, are organized and presented in the same manner as those as of November 30, 2015.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit Nos. 9, and 109.

A. I will use Account 376, Mains, as my example, inasmuch as it is the largest depreciable group and represents 64 percent of the original cost of depreciable gas plant as of November 30, 2015.

The retirement rate method was used to analyze the survivor characteristics of this group. The life tables for the 1939-2011 and 1977-2011 experience bands are presented on pages VI-50 through VI-57 of Exhibit No. 109, Schedule No. 1, Attachment A. The life tables, or original survivor curve,

are plotted along with the estimated smooth survivor curve, the 72-R1.5, on page VI-49.

The calculations of the annual depreciation related to the original cost at November 30, 2014, of gas plant are presented by type main on pages II-31 through II-37 of Exhibit No. 9. The calculation is based on the 72-R1.5 survivor curve, the attained age, and the allocated book reserve. The calculations at November 30, 2015, are presented by type main on pages VII-30 through VII-35 of Exhibit No. 109, Schedule No. 1, Attachment A and are based in part on the bringforward of the book reserve. Also, the calculations at December 31, 2016 are presented by type main on pages II-30 through II-35 of Exhibit No. 109, Schedule No. 1, Attachment B and are based in part on the bringforward of the book reserve. The tabulations in Exhibit Nos. 9 and 109 set forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to Table 1 on page I-3 in Exhibit No. 9, page V-4 in Exhibit No. 109, Schedule No. 1, Attachment A and on page I-3 in Exhibit No. 109, Schedule No. 1, Attachment B.

Q. In what manner is net salvage incorporated in the depreciation calculations?

A. As stated on page IV-9 of Exhibit No. 109, Schedule No. 1, Attachment A, no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth on page I-5 of Exhibit No. 9, page V-6 of Exhibit No. 109, Schedule No. 1, Attachment A and on page I-5 of Exhibit No. 109, Schedule No. 1, Attachment B should include an

addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2009 through 2013 for the calculation as of November 30, 2014, and on experience during the period 2010 through November 30, 2014, plus estimates for the last month of 2014 for the calculation as of November 30, 2015.

The amortization for the December 31, 2016 calculation is based on experience during the period 2011 through November 30, 2014, plus estimates for the period December 2014 through December 2016. The amounts of the five-year amortizations are calculated in Table 2 on page I-6 of Exhibit No. 9, in Table 4 on page V-11 of Exhibit No. 109, Schedule No. 1, Attachment A and in Table 4 on page I-10 of Exhibit No. 109, Schedule No. 1, Attachment B.

Q. Have you provided a monthly bringforward to December 31, 2016, of the book depreciation reserve as of November 30, 2015?

A. Yes, Exhibit JJS-01 at the end of this testimony provides the monthly detail of the book depreciation reserve and the calculated depreciation. This exhibit agrees with the fully forecasted rate year reserve balance as shown on Exhibit No. 109, Schedule No. 1, Attachment B, Table 1 on pages I-3 through I-5.

Q. Does this complete your testimony at this time?

A. Yes, it does.

APPENDIX A

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and current President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 to December 1995, I took part in the preparation of numerous depreciation and original cost studies for utility companies in various industries. Depreciation studies of telephone companies were performed for United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. My work in the railroad industry included depreciation studies for Union Pacific

Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

Assignments in the electric industry included depreciation studies for Chugach Electric Association, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Northwest Territories Power Corporation and the City of Calgary - Electric System. Pipeline industry assignments included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

My work for the gas industry included depreciation studies for Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas Company and Penn Fuel Gas, Inc. Assignments in the water industry included depreciation studies for Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

My participation in each of the above studies included assembly and analysis of historical and simulated data, field reviews, the development of preliminary estimates of service life and net salvage, calculations of annual depreciation, and the preparation of reports for submission to state or provincial public utility commissions or federal regulatory agencies. I performed these studies under the

general direction of William M. Stout, P.E., the President of Gannett Fleming Valuation and Rate Consultants, Inc.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming, Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water

Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota

Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; and Greater Missouri Operations. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. What is the extent of your formal instruction with respect to utility plant depreciation?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Have you previously testified on public utility ratemaking matters?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts

Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; and the North Carolina Utilities Commission.

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2015 DECEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		871,379
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,489	0	2,489	1,100	0	0		571,105
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,294	92	3,386	500	60	0		653,881
374.50	1,555,652	1.32			189			0	3,556	16	3,572	0	0	0		1,559,224
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,761	2,195	8,956	1,900	1,919	0		829,167
375.60	72,639	1.04			290			218	76	24	100	0	0	0		72,739
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,166	(3,757)	29,410	23,400	4,212	0		1,827,569
375.80	6,177	2.03							28	0	28	0	0	0		6,205
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,879,723	84,165	1,963,888	816,600	130,656	0		181,989,975
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	108,447	8,604	117,051	13,600	4,624	0		8,602,140
379.10	89,069	3.29			395			18	387	33	420	0	0	0		89,489
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,009,869	232,736	1,242,605	91,500	50,325	0		104,756,888
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,149	(1,070)	71,079	5,000	0	100		15,239,449
381.10	6,817,382	7.50							146,584	0	146,584	(14,300)	0	0		6,978,266
382.00	11,320,688	1.95			(12)				57,460	(1)	57,459	6,600	0	0		11,371,547
383.00	3,318,441	2.57	0.01		166	0.01		178	23,583	14	23,597	3,400	34	0		3,338,604
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,910,521
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,235	3,473	25,708	700	154	0		3,040,186
387.00	68,826	3.74			5,865			5,397	417	489	906	0	0	0		69,732
387.40	689,626	4.77			1,683			318	12,377	140	12,517	0	0	0		702,143
390.10	48,089	0.24							10	0	10	0	0	0		48,099
391.10	1,742,734	1.94							3,256	0	3,256	101,036	0	0		1,644,953
391.11	11,382	5.05							103	0	103	0	0	0		11,485
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		1,931,077
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,164)	(387)	0	0	0		53,484
393.00	16,436	0.55							8	0	8	0	0	0		16,444
394.00	5,473,958	3.68			(1,077)				38,701	(90)	38,612	209,079	0	0		5,303,490
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							19,859	0	19,859	0	0	0		129,640
395.00	31,717	6.08							257	0	257	0	0	0		31,974
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(3,307)	(1,645)	0	0	0		1,365,556
397.10	344,072	9.42			493				5,334	41	5,375	173,476	0	0		175,971
397.24	1,729,110	2.38							3,263	0	3,263	1,696,858	0	0		35,515
397.50	676,536	4.87							4,415	0	4,415	0	0	0		680,951
398.00	169,968	6.94							5,004	0	5,004	18,640	0	0		156,332
303.00	7,112,928								285,256	0	285,256	185,366	0	0		7,212,818
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	54,784	54,784	0	0	0		(901,439)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		223,713
375.71	1,098,950								2,247	0	2,247	0	0	0		1,101,197
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,799,572	378,388	4,177,960	3,334,455	191,984	100	0	368,353,559

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 JANUARY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		881,493
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,512	0	2,512	1,400	0	0		572,217
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,300	110	3,410	500	60	0		656,731
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,562,781
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,784	1,709	8,493	1,400	952	0		835,308
375.60	72,639	1.04			290			218	76	18	94	0	0	0		72,833
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,544	1,303	34,847	0	0	0		1,862,415
375.80	6,177	2.03							28	0	28	0	0	0		6,233
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,889,727	108,491	1,998,218	723,100	115,696	0		183,149,397
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	108,658	13,682	122,340	6,300	2,331	0		8,715,848
379.10	89,069	3.29			395			18	387	2	388	0	0	0		89,877
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,012,670	250,026	1,262,697	215,900	127,381	0		105,676,304
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,235	(591)	71,644	6,000	0	120		15,305,213
381.10	6,817,382	7.50							146,238	0	146,238	0	0	0		7,124,504
382.00	11,320,688	1.95			(12)				57,542	0	57,542	6,600	0	0		11,422,490
383.00	3,318,441	2.57	0.01		166	0.01		178	23,638	15	23,653	3,300	33	0		3,358,924
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,916,221
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,254	2,845	25,100	800	168	0		3,064,318
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		70,599
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		714,547
390.10	48,089	0.24							10	0	10	0	0	0		48,109
391.10	1,742,734	1.94							3,186	0	3,186	0	0	0		1,648,139
391.11	11,382	5.05							103	0	103	0	0	0		11,588
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		1,962,091
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		53,227
393.00	16,436	0.55							8	0	8	0	0	0		16,451
394.00	5,473,958	3.68			(1,077)				38,500	0	38,500	0	0	0		5,341,990
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							20,763	0	20,763	0	0	0		150,403
395.00	31,717	6.08							257	0	257	0	0	0		32,230
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,364,746
397.10	344,072	9.42			493				4,867	0	4,867	0	0	0		180,838
397.24	1,729,110	2.38							1,677	0	1,677	0	0	0		37,192
397.50	676,536	4.87							4,488	0	4,488	0	0	0		685,439
398.00	169,968	6.94							6,344	0	6,344	0	0	0		162,677
303.00	7,112,928								285,256	0	285,256	0	0	0		7,498,073
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(890,711)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		224,673
375.71	1,098,950								2,247	0	2,247	0	0	0		1,103,444
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,812,909	386,279	4,199,187	965,300	246,621	120	0	371,340,945

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 FEBRUARY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		891,608
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,536	0	2,536	1,400	0	0		573,353
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,307	110	3,417	800	96	0		659,252
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,566,337
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,805	1,709	8,514	1,700	1,156	0		840,966
375.60	72,639	1.04			290			218	76	18	94	0	0	0		72,927
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,562	1,303	34,865	1,100	198	0		1,895,983
375.80	6,177	2.03							28	0	28	0	0	0		6,261
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,898,976	108,491	2,007,467	722,200	115,552	0		184,319,112
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	108,802	13,682	122,484	7,500	2,775	0		8,828,057
379.10	89,069	3.29			395			18	387	2	388	0	0	0		90,266
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,016,744	250,026	1,266,770	235,000	138,650	0		106,569,424
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,337	(591)	71,746	7,200	0	144		15,369,902
381.10	6,817,382	7.50							146,240	0	146,240	0	0	0		7,270,744
382.00	11,320,688	1.95			(12)				57,637	0	57,637	8,800	0	0		11,471,327
383.00	3,318,441	2.57	0.01		166	0.01		178	23,705	15	23,720	4,900	49	0		3,377,695
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,921,922
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,276	2,845	25,121	1,000	210	0		3,088,229
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		71,466
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		726,950
390.10	48,089	0.24							10	0	10	0	0	0		48,119
391.10	1,742,734	1.94							3,187	0	3,187	0	0	0		1,651,326
391.11	11,382	5.05							103	0	103	0	0	0		11,690
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		1,993,106
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		52,971
393.00	16,436	0.55							8	0	8	0	0	0		16,459
394.00	5,473,958	3.68			(1,077)				38,503	0	38,503	0	0	0		5,380,493
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							20,793	0	20,793	0	0	0		171,195
395.00	31,717	6.08							257	0	257	0	0	0		32,487
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,363,935
397.10	344,072	9.42			493				4,877	0	4,877	0	0	0		185,715
397.24	1,729,110	2.38							1,681	0	1,681	0	0	0		38,873
397.50	676,536	4.87							4,491	0	4,491	0	0	0		689,930
398.00	169,968	6.94							6,344	0	6,344	0	0	0		169,021
303.00	7,112,928								285,256	0	285,256	0	0	0		7,783,329
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(879,982)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		225,634
375.71	1,098,950								2,247	0	2,247	0	0	0		1,105,690
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,826,783	386,279	4,213,061	991,600	258,686	144	0	374,303,864

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

			PROJECTED 15			PROJECTED 2016			2016							
	2015	'Accrual			'5-yr			'5-yr	MARCH							
Account	NOV 30 Begin. Balance	Rates 2015	COR % of Rets	Salvage % of Rets	Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	Amort of NS 2011-2015	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		901,722
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,567	0	2,567	2,300	0	0		573,620
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,317	110	3,427	1,100	132	0		661,447
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,569,893
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,833	1,709	8,543	2,500	1,700	0		845,308
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,022
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,598	1,303	34,901	1,100	198	0		1,929,586
375.80	6,177	2.03							28	0	28	0	0	0		6,289
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,911,750	108,491	2,020,241	1,274,000	203,840	0		184,861,513
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	108,997	13,682	122,678	11,200	4,144	0		8,935,391
379.10	89,069	3.29			395			18	387	2	388	0	0	0		90,654
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,022,160	250,026	1,272,186	364,500	215,055	0		107,262,055
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,475	(591)	71,884	10,700	0	214		15,431,300
381.10	6,817,382	7.50							146,241	0	146,241	0	0	0		7,416,985
382.00	11,320,688	1.95			(12)				57,768	0	57,768	12,600	0	0		11,516,495
383.00	3,318,441	2.57	0.01		166	0.01		178	23,800	15	23,814	6,800	68	0		3,394,641
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,927,622
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,305	2,845	25,151	1,500	315	0		3,111,565
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		72,333
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		739,354
390.10	48,089	0.24							10	0	10	0	0	0		48,129
391.10	1,742,734	1.94							3,188	0	3,188	0	0	0		1,654,514
391.11	11,382	5.05							103	0	103	0	0	0		11,793
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		2,024,120
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		52,715
393.00	16,436	0.55							8	0	8	0	0	0		16,467
394.00	5,473,958	3.68			(1,077)				38,511	0	38,511	0	0	0		5,419,004
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							20,849	0	20,849	0	0	0		192,045
395.00	31,717	6.08							257	0	257	0	0	0		32,744
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,363,125
397.10	344,072	9.42			493				4,894	0	4,894	0	0	0		190,609
397.24	1,729,110	2.38							1,689	0	1,689	0	0	0		40,563
397.50	676,536	4.87							4,497	0	4,497	0	0	0		694,427
398.00	169,968	6.94							6,344	0	6,344	0	0	0		175,366
303.00	7,112,928								285,256	0	285,256	0	0	0		8,068,584
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(869,253)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		226,594
375.71	1,098,950								2,247	0	2,247	0	0	0		1,107,937
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,845,764	386,279	4,232,043	1,688,300	425,452	214	0	376,422,369

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 **Number of months in FFTY =** 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 APRIL Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		911,837
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,611	0	2,611	2,900	0	0		573,330
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,328	110	3,438	1,000	120	0		663,765
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,573,450
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,869	1,709	8,579	2,700	1,836	0		849,351
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,116
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,650	1,303	34,953	2,200	396	0		1,961,942
375.80	6,177	2.03							28	0	28	0	0	0		6,317
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,930,205	108,491	2,038,696	1,609,900	257,584	0		185,032,724
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	109,244	13,682	122,926	12,500	4,625	0		9,041,192
379.10	89,069	3.29			395			18	387	2	388	0	0	0		91,042
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,029,343	250,026	1,279,369	430,600	254,054	0		107,856,770
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,650	(591)	72,059	12,000	0	240		15,491,599
381.10	6,817,382	7.50							146,243	0	146,243	100	0	0		7,563,128
382.00	11,320,688	1.95			(12)				57,925	0	57,925	13,100	0	0		11,561,320
383.00	3,318,441	2.57	0.01		166	0.01		178	23,907	15	23,922	6,500	65	0		3,411,998
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,933,323
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,343	2,845	25,189	1,600	336	0		3,134,818
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		73,200
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		751,758
390.10	48,089	0.24							10	0	10	0	0	0		48,139
391.10	1,742,734	1.94							3,191	0	3,191	0	0	0		1,657,705
391.11	11,382	5.05							103	0	103	0	0	0		11,896
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		2,055,135
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		52,458
393.00	16,436	0.55							8	0	8	0	0	0		16,474
394.00	5,473,958	3.68			(1,077)				38,522	0	38,522	0	0	0		5,457,526
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							20,932	0	20,932	0	0	0		212,977
395.00	31,717	6.08							257	0	257	0	0	0		33,000
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,362,314
397.10	344,072	9.42			493				4,920	0	4,920	0	0	0		195,529
397.24	1,729,110	2.38							1,701	0	1,701	0	0	0		42,264
397.50	676,536	4.87							4,506	0	4,506	0	0	0		698,933
398.00	169,968	6.94							6,344	0	6,344	0	0	0		181,710
303.00	7,112,928								285,256	0	285,256	0	0	0		8,353,840
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(858,524)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		227,555
375.71	1,098,950								2,247	0	2,247	0	0	0		1,110,184
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,872,414	386,279	4,258,693	2,095,100	519,016	240	0	378,067,186

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 MAY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		921,952
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,665	0	2,665	3,500	0	0		572,496
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,339	110	3,449	1,000	120	0		666,094
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,577,006
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,910	1,709	8,619	3,100	2,108	0		852,762
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,210
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,731	1,303	35,034	3,000	540	0		1,993,436
375.80	6,177	2.03							28	0	28	0	0	0		6,345
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,953,487	108,491	2,061,977	2,028,300	324,528	0		184,741,874
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	109,529	13,682	123,210	14,700	5,439	0		9,144,263
379.10	89,069	3.29			395			18	387	2	388	0	0	0		91,431
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,037,866	250,026	1,287,892	512,800	302,552	0		108,329,310
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	72,850	(591)	72,259	14,000	0	280		15,550,138
381.10	6,817,382	7.50							147,031	0	147,031	33,400	0	0		7,676,759
382.00	11,320,688	1.95			(12)				58,097	0	58,097	14,900	0	0		11,604,517
383.00	3,318,441	2.57	0.01		166	0.01		178	24,018	15	24,033	7,200	72	0		3,428,759
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,939,023
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,387	2,845	25,232	1,900	399	0		3,157,751
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		74,067
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		764,161
390.10	48,089	0.24							10	0	10	0	0	0		48,149
391.10	1,742,734	1.94							3,194	0	3,194	0	0	0		1,660,899
391.11	11,382	5.05							103	0	103	0	0	0		11,999
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		2,086,150
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		52,202
393.00	16,436	0.55							8	0	8	0	0	0		16,482
394.00	5,473,958	3.68			(1,077)				38,539	0	38,539	0	0	0		5,496,065
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,062	0	21,062	0	0	0		234,039
395.00	31,717	6.08							257	0	257	0	0	0		33,257
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,361,504
397.10	344,072	9.42			493				4,960	0	4,960	0	0	0		200,489
397.24	1,729,110	2.38							1,719	0	1,719	0	0	0		43,983
397.50	676,536	4.87							4,519	0	4,519	0	0	0		703,452
398.00	169,968	6.94							6,344	0	6,344	0	0	0		188,055
303.00	7,112,928								285,256	0	285,256	0	0	0		8,639,095
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(847,795)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		228,516
375.71	1,098,950								2,247	0	2,247	0	0	0		1,112,431
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,906,228	386,279	4,292,507	2,637,800	635,758	280	0	379,086,415

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 JUNE Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		932,066
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,724	0	2,724	3,400	0	0		571,820
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,351	110	3,461	1,200	144	0		668,211
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,580,563
375.34	824,030	2.23	1.01		26,343	0.68		20,509	6,955	1,709	8,664	3,200	2,176	0		856,050
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,304
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,805	1,303	35,108	1,800	324	0		2,026,420
375.80	6,177	2.03							28	0	28	0	0	0		6,373
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	1,981,072	108,491	2,089,563	2,282,400	365,184	0		184,183,853
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	109,838	13,682	123,519	14,900	5,513	0		9,247,369
379.10	89,069	3.29			395			18	387	2	388	0	0	0		91,819
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,047,085	250,026	1,297,111	507,600	299,484	0		108,819,337
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	73,068	(591)	72,477	14,200	0	284		15,608,698
381.10	6,817,382	7.50							147,818	0	147,818	0	0	0		7,824,577
382.00	11,320,688	1.95			(12)				58,285	0	58,285	15,800	0	0		11,647,002
383.00	3,318,441	2.57	0.01		166	0.01		178	24,141	15	24,156	8,000	80	0		3,444,834
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,944,724
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,434	2,845	25,280	1,900	399	0		3,180,732
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		74,933
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		776,565
390.10	48,089	0.24							10	0	10	0	0	0		48,159
391.10	1,742,734	1.94							3,198	0	3,198	0	0	0		1,664,097
391.11	11,382	5.05							103	0	103	0	0	0		12,102
391.12	1,900,062	14.59							31,015	0	31,015	0	0	0		2,117,164
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		51,946
393.00	16,436	0.55							8	0	8	0	0	0		16,489
394.00	5,473,958	3.68			(1,077)				38,555	0	38,555	0	0	0		5,534,619
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,182	0	21,182	0	0	0		255,222
395.00	31,717	6.08							257	0	257	0	0	0		33,514
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,360,693
397.10	344,072	9.42			493				4,997	0	4,997	0	0	0		205,486
397.24	1,729,110	2.38							1,736	0	1,736	0	0	0		45,719
397.50	676,536	4.87							4,532	0	4,532	0	0	0		707,984
398.00	169,968	6.94							6,344	0	6,344	0	0	0		194,399
303.00	7,112,928								285,256	0	285,256	0	0	0		8,924,351
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(837,066)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		229,476
375.71	1,098,950								2,247	0	2,247	0	0	0		1,114,677
389.20	39								0	0	0	0	0	0		39
Total	**367,701,938**				**4,540,655**			**4,635,342**	**3,945,100**	**386,279**	**4,331,378**	**2,854,400**	**673,304**	**284**	**0**	**379,890,373**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 JULY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		942,181
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,782	0	2,782	3,800	0	0		570,802
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,365	110	3,475	1,700	204	0		669,782
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,584,119
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,003	1,709	8,712	4,000	2,720	0		858,042
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,398
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,862	1,303	35,165	2,000	360	0		2,059,224
375.80	6,177	2.03							28	0	28	0	0	0		6,401
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,010,304	108,491	2,118,794	2,505,100	400,816	0		183,396,731
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	110,167	13,682	123,848	18,200	6,734	0		9,346,284
379.10	89,069	3.29			395			18	387	2	388	0	0	0		92,208
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,056,605	250,026	1,306,631	598,600	353,174	0		109,174,194
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	73,301	(591)	72,709	17,400	0	348		15,664,356
381.10	6,817,382	7.50							147,760	0	147,760	(2,800)	0	0		7,975,137
382.00	11,320,688	1.95			(12)				58,495	0	58,495	20,300	0	0		11,685,196
383.00	3,318,441	2.57	0.01		166	0.01		178	24,285	15	24,300	10,800	108	0		3,458,227
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,950,424
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,485	2,845	25,330	2,400	504	0		3,203,158
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		75,800
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		788,968
390.10	48,089	0.24							10	0	10	0	0	0		48,169
391.10	1,742,734	1.94							3,200	0	3,200	0	0	0		1,667,297
391.11	11,382	5.05							103	0	103	0	0	0		12,204
391.12	1,900,062	14.59							33,585	0	33,585	0	0	0		2,150,750
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		51,689
393.00	16,436	0.55							8	0	8	0	0	0		16,497
394.00	5,473,958	3.68			(1,077)				38,567	0	38,567	0	0	0		5,573,186
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,274	0	21,274	0	0	0		276,495
395.00	31,717	6.08							257	0	257	0	0	0		33,770
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,359,883
397.10	344,072	9.42			493				5,026	0	5,026	0	0	0		210,512
397.24	1,729,110	2.38							1,749	0	1,749	0	0	0		47,468
397.50	676,536	4.87							4,541	0	4,541	0	0	0		712,525
398.00	169,968	6.94							6,344	0	6,344	0	0	0		200,743
303.00	7,112,928								285,256	0	285,256	0	0	0		9,209,606
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(826,337)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		230,437
375.71	1,098,950								2,247	0	2,247	0	0	0		1,116,924
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	3,987,664	386,279	4,373,943	3,181,500	764,620	348	0	380,318,544

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 AUGUST Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		952,295
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,833	0	2,833	2,500	0	0		571,135
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,379	110	3,489	1,000	120	0		672,151
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,587,676
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,046	1,709	8,755	2,500	1,700	0		862,598
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,492
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	33,936	1,303	35,238	2,900	522	0		2,091,041
375.80	6,177	2.03							28	0	28	0	0	0		6,428
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,037,530	108,491	2,146,020	1,968,900	315,024	0		183,258,828
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	110,462	13,682	124,144	11,700	4,329	0		9,454,398
379.10	89,069	3.29			395			18	387	2	388	0	0	0		92,596
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,065,071	250,026	1,315,097	391,000	230,690	0		109,867,601
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	73,510	(591)	72,918	11,100	0	222		15,726,396
381.10	6,817,382	7.50							147,704	0	147,704	100	0	0		8,122,740
382.00	11,320,688	1.95			(12)				58,685	0	58,685	12,600	0	0		11,731,282
383.00	3,318,441	2.57	0.01		166	0.01		178	24,418	15	24,433	6,500	65	0		3,476,094
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,956,125
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,529	2,845	25,375	1,500	315	0		3,226,718
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		76,667
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		801,372
390.10	48,089	0.24							10	0	10	0	0	0		48,179
391.10	1,742,734	1.94							3,203	0	3,203	0	0	0		1,670,501
391.11	11,382	5.05							103	0	103	0	0	0		12,307
391.12	1,900,062	14.59							36,156	0	36,156	0	0	0		2,186,906
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		51,433
393.00	16,436	0.55							8	0	8	0	0	0		16,505
394.00	5,473,958	3.68			(1,077)				38,582	0	38,582	0	0	0		5,611,768
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,393	0	21,393	0	0	0		297,888
395.00	31,717	6.08							257	0	257	0	0	0		34,027
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,359,072
397.10	344,072	9.42			493				5,062	0	5,062	0	0	0		215,574
397.24	1,729,110	2.38							1,766	0	1,766	0	0	0		49,233
397.50	676,536	4.87							4,554	0	4,554	0	0	0		717,079
398.00	169,968	6.94							6,344	0	6,344	0	0	0		207,088
303.00	7,112,928								285,256	0	285,256	526,497	0	0		8,968,365
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(815,608)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		231,397
375.71	1,098,950								2,247	0	2,247	0	0	0		1,119,171
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	4,027,129	386,279	4,413,407	2,938,797	552,765	222	0	381,240,611

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 SEPTEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		962,410
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,882	0	2,882	3,200	0	0		570,818
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,392	110	3,502	1,400	168	0		674,086
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,591,232
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,087	1,709	8,796	3,300	2,244	0		865,850
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,586
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	34,011	1,303	35,314	2,000	360	0		2,123,994
375.80	6,177	2.03							28	0	28	0	0	0		6,456
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,063,927	108,491	2,172,417	2,156,100	344,976	0		182,930,169
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	110,742	13,682	124,423	15,100	5,587	0		9,558,135
379.10	89,069	3.29			395			18	387	2	388	0	0	0		92,984
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,073,137	250,026	1,323,163	501,800	296,062	0		110,392,902
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	73,707	(591)	73,116	14,500	0	290		15,785,302
381.10	6,817,382	7.50							147,707	0	147,707	0	0	0		8,270,447
382.00	11,320,688	1.95			(12)				58,865	0	58,865	16,700	0	0		11,773,446
383.00	3,318,441	2.57	0.01		166	0.01		178	24,542	15	24,557	8,800	88	0		3,491,763
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,961,825
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,572	2,845	25,417	2,000	420	0		3,249,715
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		77,534
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		813,775
390.10	48,089	0.24							10	0	10	0	0	0		48,189
391.10	1,742,734	1.94							3,207	0	3,207	0	0	0		1,673,707
391.11	11,382	5.05							103	0	103	0	0	0		12,410
391.12	1,900,062	14.59							36,156	0	36,156	0	0	0		2,223,063
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		51,177
393.00	16,436	0.55							8	0	8	0	0	0		16,512
394.00	5,473,958	3.68			(1,077)				38,598	0	38,598	0	0	0		5,650,366
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,513	0	21,513	0	0	0		319,401
395.00	31,717	6.08							257	0	257	0	0	0		34,284
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,358,261
397.10	344,072	9.42			493				5,100	0	5,100	0	0	0		220,674
397.24	1,729,110	2.38							1,783	0	1,783	0	0	0		51,016
397.50	676,536	4.87							4,567	0	4,567	0	0	0		721,646
398.00	169,968	6.94							6,344	0	6,344	0	0	0		213,432
303.00	7,112,928								285,256	0	285,256	0	0	0		9,253,620
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(804,879)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		232,358
375.71	1,098,950								2,247	0	2,247	0	0	0		1,121,418
389.20	39								0	0	0	0	0	0		39
Total	**367,701,938**				**4,540,655**			**4,635,342**	**4,062,804**	**386,279**	**4,449,082**	**2,724,900**	**649,905**	**290**	**0**	**382,315,178**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 **Number of months in FFTY =** 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 OCTOBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		972,524
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,939	0	2,939	3,700	0	0		570,056
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,405	110	3,515	1,100	132	0		676,368
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,594,788
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,131	1,709	8,840	3,300	2,244	0		869,146
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,681
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	34,087	1,303	35,390	3,300	594	0		2,155,491
375.80	6,177	2.03							28	0	28	0	0	0		6,484
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,090,183	108,491	2,198,674	2,139,300	342,288	0		182,647,255
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	111,047	13,682	124,728	15,500	5,735	0		9,661,628
379.10	89,069	3.29			395			18	387	2	388	0	0	0		93,373
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,082,119	250,026	1,332,145	541,100	319,249	0		110,864,699
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	73,922	(591)	73,331	14,700	0	294		15,844,227
381.10	6,817,382	7.50							148,071	0	148,071	17,000	0	0		8,401,519
382.00	11,320,688	1.95			(12)				59,054	0	59,054	15,600	0	0		11,816,901
383.00	3,318,441	2.57	0.01		166	0.01		178	24,668	15	24,683	7,500	75	0		3,508,871
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,967,526
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,619	2,845	25,464	2,000	420	0		3,272,759
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		78,401
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		826,179
390.10	48,089	0.24							10	0	10	0	0	0		48,199
391.10	1,742,734	1.94							3,210	0	3,210	0	0	0		1,676,918
391.11	11,382	5.05							103	0	103	0	0	0		12,513
391.12	1,900,062	14.59							36,156	0	36,156	0	0	0		2,259,219
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		50,920
393.00	16,436	0.55							8	0	8	0	0	0		16,520
394.00	5,473,958	3.68			(1,077)				38,614	0	38,614	0	0	0		5,688,980
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,638	0	21,638	0	0	0		341,039
395.00	31,717	6.08							257	0	257	0	0	0		34,541
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,357,451
397.10	344,072	9.42			493				5,138	0	5,138	0	0	0		225,812
397.24	1,729,110	2.38							1,800	0	1,800	0	0	0		52,816
397.50	676,536	4.87							4,580	0	4,580	0	0	0		726,226
398.00	169,968	6.94							6,344	0	6,344	0	0	0		219,777
303.00	7,112,928								285,256	0	285,256	0	0	0		9,538,876
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(794,150)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		233,318
375.71	1,098,950								2,247	0	2,247	0	0	0		1,123,664
389.20	39								0	0	0	0	0	0		39
Total	**367,701,938**				**4,540,655**			**4,635,342**	**4,099,693**	**386,279**	**4,485,971**	**2,764,100**	**670,737**	**294**	**0**	**383,366,606**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 NOVEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		982,639
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,982	0	2,982	1,800	0	0		571,238
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,413	110	3,523	700	84	0		679,107
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,598,345
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,164	1,709	8,873	1,700	1,156	0		875,164
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,775
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	34,176	1,303	35,479	2,700	486	0		2,187,784
375.80	6,177	2.03							28	0	28	0	0	0		6,512
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,110,566	108,491	2,219,057	1,238,200	198,112	0		183,430,000
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	111,276	13,682	124,958	7,900	2,923	0		9,775,763
379.10	89,069	3.29			395			18	387	2	388	0	0	0		93,761
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,088,977	250,026	1,339,003	266,600	157,294	0		111,779,808
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	74,084	(591)	73,493	7,600	0	152		15,910,272
381.10	6,817,382	7.50							148,811	0	148,811	15,900	0	0		8,534,430
382.00	11,320,688	1.95			(12)				59,193	0	59,193	8,500	0	0		11,867,594
383.00	3,318,441	2.57	0.01		166	0.01		178	24,759	15	24,773	4,400	44	0		3,529,200
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,973,227
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,654	2,845	25,499	1,000	210	0		3,297,048
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		79,268
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		838,583
390.10	48,089	0.24							10	0	10	0	0	0		48,209
391.10	1,742,734	1.94							3,214	0	3,214	0	0	0		1,680,132
391.11	11,382	5.05							103	0	103	0	0	0		12,616
391.12	1,900,062	14.59							36,156	0	36,156	0	0	0		2,295,375
392.00	53,871	9.56			(13,972)		0.44	(12,400)	777	(1,033)	(256)	0	0	0		50,664
393.00	16,436	0.55							8	0	8	0	0	0		16,528
394.00	5,473,958	3.68			(1,077)				38,633	0	38,633	0	0	0		5,727,614
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							21,781	0	21,781	0	0	0		362,820
395.00	31,717	6.08							257	0	257	0	0	0		34,797
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,356,640
397.10	344,072	9.42			493				5,183	0	5,183	0	0	0		230,995
397.24	1,729,110	2.38							1,820	0	1,820	0	0	0		54,636
397.50	676,536	4.87							4,595	0	4,595	0	0	0		730,820
398.00	169,968	6.94							6,344	0	6,344	0	0	0		226,121
303.00	7,112,928								285,256	0	285,256	0	0	0		9,824,131
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	0	0		(783,421)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		234,279
375.71	1,098,950								2,247	0	2,247	0	0	0		1,125,911
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	4,128,748	386,279	4,515,027	1,557,000	360,309	152	0	385,964,476

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 15 PROJECTED 2016

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015	2016 DECEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	861,264	3.87			122			122	10,104	10	10,115	0	0	0		992,754
352.01	799,118	0.00							0	0	0	0	0	0		799,118
352.02	168,680	0.00							0	0	0	0	0	0		168,680
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	405,288	0.00							0	0	0	0	0	0		405,288
354.00	569,716	2.71							2,997	0	2,997	(100)	0	0		574,335
355.00	123,010	0.00							0	0	0	0	0	0		123,010
374.40	651,055	1.71	0.12		1,108	0.12		1,321	3,420	110	3,530	600	72	0		681,965
374.50	1,555,652	1.32			189			0	3,556	0	3,556	0	0	0		1,601,901
375.34	824,030	2.23	1.01		26,343	0.68		20,509	7,180	1,709	8,889	600	408	0		883,045
375.60	72,639	1.04			290			218	76	18	94	0	0	0		73,869
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635	36,606	1,303	37,909	164,400	29,592	0		2,031,701
375.80	6,177	2.03							28	0	28	0	0	0		6,540
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889	2,119,802	108,491	2,228,292	220,600	35,296	0		185,402,396
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179	111,380	13,682	125,061	2,200	814	0		9,897,811
379.10	89,069	3.29			395			18	387	2	388	0	0	0		94,150
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315	1,091,725	250,026	1,341,752	40,500	23,895	0		113,057,164
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)	74,158	(591)	73,567	2,200	0	44		15,981,682
381.10	6,817,382	7.50							148,843	0	148,843	(15,700)	0	0		8,698,973
382.00	11,320,688	1.95			(12)				59,268	0	59,268	4,000	0	0		11,922,861
383.00	3,318,441	2.57	0.01		166	0.01		178	24,815	15	24,830	2,900	29	0		3,551,101
384.00	2,904,820	1.77			1				5,701	0	5,701	0	0	0		2,978,927
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144	22,669	2,845	25,515	300	63	0		3,322,200
387.00	68,826	3.74			5,865			5,397	417	450	867	0	0	0		80,135
387.40	689,626	4.77			1,683			318	12,377	27	12,404	0	0	0		850,986
390.10	48,089	0.24							10	0	10	0	0	0		48,219
391.10	1,742,734	1.94							3,111	0	3,111	260,946	0	0		1,422,297
391.11	11,382	5.05							103	0	103	0	0	0		12,718
391.12	1,900,062	14.59							24,613	0	24,613	1,898,784	0	0		421,205
392.00	53,871	9.56			(13,972)		0.44	(12,400)	756	(1,033)	(277)	5,209	0	2,292		47,470
393.00	16,436	0.55							7	0	7	2,300	0	0		14,235
394.00	5,473,958	3.68			(1,077)				38,908	0	38,908	158,166	0	0		5,608,356
394.12	1,953,286	0.00							0	0	0	0	0	0		1,953,286
394.50	109,781	10.36							25,717	0	25,717	0	0	0		388,538
395.00	31,717	6.08							221	0	221	13,946	0	0		21,073
396.00	1,367,201	1.39			(39,688)			(29,680)	1,663	(2,473)	(811)	0	0	0		1,355,830
397.10	344,072	9.42			493				5,739	0	5,739	168,831	0	0		67,903
397.24	1,729,110	2.38							2,372	0	2,372	0	0	0		57,008
397.50	676,536	4.87							5,007	0	5,007	0	0	0		735,828
398.00	169,968	6.94							6,233	0	6,233	38,545	0	0		193,810
303.00	7,112,928								285,256	0	285,256	666,156	0	0		9,443,231
305.00	(4,583)								0	0	0	0	0	0		(4,583)
362.00	(1,609)								0	0	0	0	0	0		(1,609)
362.10	(956,223)				657,403			128,747	0	10,729	10,729	0	25,000	0		(797,692)
374.20	222,752				11,527			11,527	0	961	961	0	0	0		235,240
375.71	1,098,950								0	0	0	0	0	0		1,125,911
389.20	39								0	0	0	0	0	0		39
Total	367,701,938				4,540,655			4,635,342	4,135,226	386,279	4,521,505	3,635,382	115,169	2,336	0	386,737,766

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

Account	2015 NOV 30 Begin. Balance	'Accrual Rates 2015	PROJECTED 15 COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2010-2014	PROJECTED 2016 COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2011-2015
350.20	1,931	0.00						
351.20	861,264	3.87			122			122
352.01	799,118	0.00						
352.02	168,680	0.00						
352.10	206,932	0.00						
353.00	405,288	0.00						
354.00	569,716	2.71						
355.00	123,010	0.00						
374.40	651,055	1.71	0.12		1,108	0.12		1,321
374.50	1,555,652	1.32			189			0
375.34	824,030	2.23	1.01		26,343	0.68		20,509
375.60	72,639	1.04			290			218
375.70	1,825,771	4.98	0.18	0.00	(45,078)	0.18	0.00	15,635
375.80	6,177	2.03						
376.00	180,973,343	2.04	0.16		1,009,978	0.16		1,301,889
378.00	8,503,313	3.33	0.34		103,247	0.37		164,179
379.10	89,069	3.29			395			18
380.00	103,656,108	2.88	0.55		2,792,833	0.59		3,000,315
381.00	15,173,270	2.46		0.02	(12,838)		0.02	(7,095)
381.10	6,817,382	7.50						
382.00	11,320,688	1.95			(12)			
383.00	3,318,441	2.57	0.01		166	0.01		178
384.00	2,904,820	1.77			1			
385.00	3,015,332	3.89	0.22		41,677	0.21		34,144
387.00	68,826	3.74			5,865			5,397
387.40	689,626	4.77			1,683			318
390.10	48,089	0.24						
391.10	1,742,734	1.94						
391.11	11,382	5.05						
391.12	1,900,062	14.59						
392.00	53,871	9.56			(13,972)		0.44	(12,400)
393.00	16,436	0.55						
394.00	5,473,958	3.68			(1,077)			
394.12	1,953,286	0.00						
394.50	109,781	10.36						
395.00	31,717	6.08						
396.00	1,367,201	1.39			(39,688)			(29,680)
397.10	344,072	9.42			493			
397.24	1,729,110	2.38						
397.50	676,536	4.87						
398.00	169,968	6.94						
303.00	7,112,928							
305.00	(4,583)							
362.00	(1,609)							
362.10	(956,223)				657,403			128,747
374.20	222,752				11,527			11,527
375.71	1,098,950							
389.20	39							
Total	**367,701,938**				**4,540,655**			**4,635,342**

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICOLE M.PALONEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

I. Introduction

Q. Please state your name and business address.

A. Nicole Paloney, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004, and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and medical products to the Health Care industry, and is also a manufacturer of medical and surgical products. I was a manager in Internal Audit during my tenure at

Cardinal, with responsibility over internal audits that took place in the manufacturing and corporate segments of the company.

In August 2008, I joined NiSource Corporate Services Company ("NCSC") as an Internal Audit manager, with responsibility for internal audits that took place in NiSource Inc.'s ("NiSource") Gas Distribution segment. In September 2011, I transitioned to the Regulatory Strategy and Support group in the role of Project Manager, providing support to the state regulatory teams in Pennsylvania and Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs for the Company.

Q. Have you previously testified before this Commission or any other Commission?

A. While I have not previously testified before this Commission, I have testified before the Maryland Public Service Commission ("PSC") on behalf of Columbia Gas of Maryland as a cost of service witness in Case No. 9316 and a policy witness in Case No. 9354.

Q. What test year will you be addressing in your testimony?

A. I will be addressing the twelve month period ending November 30, 2014 as the Historic Test year, the twelve month period ended November 30, 2015 as the Future Test Year and the twelve month period ended December 31, 2016 as the Fully Forecasted Rate Year.

Q. Please describe the scope of your testimony in this proceeding.

A. First, I am supporting the exhibits listed and described in the following table:

Exhibit No.	Description
Exhibit No. 8	Historic test year rate base
Exhibit No. 10, Schedule 3(22)	Supporting data detailing curtailment adjustments, procedures and policies.
Exhibit No. 10, Schedule 4 (38) (39)	Company policy with respect to replacing customers lost through attrition and procedures to govern relationships between respondent and potential customers
Exhibit No. 10, Schedule 5(4)	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.- Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification.
Exhibit No. 10, Schedule 7	Sales by customer class, sources of gas supply and line losses
Exhibit No. 12, Schedule 1 (5)	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit No. 12. Schedule 2	Net fuel clause adjustment by month for the test year
Exhibit No. 12, Schedule 3	Statement of over/under collection from gas cost rate
Exhibit No. 12, Schedule 4(24)	Purchased gas for test year and prior year
Exhibit No. 12, Schedule 4(25)	Energy cost per Dth and operating ratio
Exhibit No. 12, Schedule 4(26)	Bulk transmission service costs
Exhibit No. 12, Schedule 4(30)	Purchased gas detail
Exhibit No. 12, Schedule 4(36)	Amounts of gas obtained through various suppliers
Exhibit No. 12, Schedule 5 (31)	Determination of fuel costs
Exhibit No. 12 Schedule 6 (11)	Net fuel clause adjustment
Exhibit No. 12, Schedule 7	Adjustment of purchased gas expense
Exhibit No. 12, Schedule 8	Statement of over/under collection from gas cost rate and recovery of fuel costs by the utility
Exhibit No. 13, Schedule 4(46)	Internal and independent audit reports of the test year and prior calendar year
Exhibit No. 13, Schedule 6(27)	Schedule of gas producing units retired or scheduled for retirement

Exhibit No. 15	Corporate history; overall system map; map of gas system facilities and gas service areas; and affiliate relationships
Exhibit No. 16 (7)	Recovery of uncollectible and delinquent accounts
Exhibit No. 17, Page 1(1)	Description of all property; gas supply; service agreements
Exhibit No. 17, Page 7(28)	Details of firm gas--affiliated and non-affiliated utilities
Exhibit No. 108	Future test year and fully forecasted test year rate base
Exhibit No. 110, Schedule 3(22)	Supporting data detailing curtailment adjustments, procedures and policies
Exhibit No. 110, Schedule 4	Company policy with respect to replacing customers lost through attrition and procedures to govern relationships between respondent and potential customers
Exhibit No. 110, Schedule 5(4)	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.-Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification
Exhibit No. 110, Schedule 7	Sales by customer class, sources of gas supply and line losses
Exhibit No. 112, Schedule 1(5)	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit No. 112, Schedule 2(18)	Fuel Adjustment Clause
Exhibit No. 112, Schedule 2(23)	Fuel cost in excess of base compared to fuel cost recovery
Exhibit No. 112, Schedule 2(24)	Purchased gas for test year and prior year
Exhibit No. 112, Schedule 2(25)	Energy cost and operating ratio used to determine increase in costs to serve additional load
Exhibit No. 112, Schedule 2(26)	Bulk transmission service costs
Exhibit No. 112, Schedule 2(30)	Purchased gas detail
Exhibit No. 112, Schedule 2(31)	Fuel costs included in the base cost of fuel
Exhibit No. 112, Schedule 2(36)	Amounts of gas obtained through various suppliers

Exhibit No. 112, Schedule 2(11)	Net fuel clause adjustment by month for the test year
Exhibit No. 112, Schedule 3	Adjustment of purchased gas expense
Exhibit No. 112, Schedule 4	Statement of over/under collection from gas cost rate and recovery of fuel costs by the utility
Exhibit No. 113, Schedule 3 (19), (39), (40), (41), (44), (45) and (46)	Internal and independent audit reports of the test year and prior calendar year
Exhibit No. 113, Schedule 4 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 115	Corporate history; overall system map; and affiliate relationships
Exhibit No. 116(7)	Recovery of uncollectibles and delinquent accounts
Exhibit No. 117, Page 1(1)	Description of all property; gas supply; service agreements
Exhibit No. 117, Page 1(28)	Details of firm gas--affiliated and non-affiliated utilities

Q. What matters will you address in your testimony?

A. I will present a schedule that demonstrates Columbia's rate base as of December 31, 2016. I will also describe the Company's rate base reflected in the revenue requirement presented in this proceeding.

I. Rate Base

Q. Is the forward looking rate year utilized by Columbia in this case similar to that used in its prior base rate case?

A. Yes. Columbia elected to use the Fully Forecasted Rate Year specifically provided for in Act 11 of 2012 in Docket Nos. R-2012-2321748 and R-2014-2406274 and has made the same election in the current case.

Q. Are there any requirements in subsequent cases arising from the use of a Fully

Forecasted Rate Year?

A. Yes. Pursuant to paragraph 25 of the approved settlement in Columbia's 2014 rate case, (Docket No. R-2014-2406274), Columbia is required to provide the Commission and other parties, on or before April 1, 2015, an update of Columbia Exhibit 108, Schedule 1, which will include actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2014. Exhibit NMP-1 provides a monthly accounting of actual Gas Plant in Service additions and retirements in the format mirroring Exhibit 108 of the prior case. Total Gas Plant in Service as of December 31, 2014 as shown on Exhibit NMP-1 is $1,593,009,176. Projected total Gas Plant in Service as of December 31, 2014 from R-2014-2406274 was $1,579,180,608.

Columbia is also required to update Exhibit 108, Schedule 1 filed in Case R-2014-2406274 for the twelve months ending December 31, 2015 on or before April 1, 2016. Finally, in the next base rate proceeding, the Company will be required to prepare a comparison of actual expenses and rate base additions for the twelve months ended December 31, 2015 to projections at Docket No. R-2014-2406274.

Q. In Exhibit NMP-1, please explain the positive balances in Retirements for Cast Iron in the month of February, as well as the positive balance for Bare Steel additions in the month of February.

A. The positive balances represent misclassifications corrected by accounting in subsequent periods.

Q. Please explain the development of rate base at November 30, 2014 for the Historic Test Year, November 30, 2015 for the Future Test Year and December 31, 2016 for the Fully Forecasted Rate Year.

A. Rate base is summarized on Exhibit 8, page 3, and further detailed by the various components in Exhibit 8, Schedules 1-10, for the Historic Test Year. Rate base for the Future Test Year and the Fully Forecasted Rate Year are summarized on Exhibit 108, Page 3 and further detailed by the various components in Exhibit 108, Schedules 1-10. The Company's Fully Forecasted Rate Year rate base claim is $1,325,130,928.

Q. Please discuss the amounts included in Property, Plant and Equipment for the Historic Test Year as illustrated on Exhibit 8, Page 3.

A. The Company's Plant in Service includes plant in service per books as of November 30, 2014 in account 101 and 106. The Company will not be making a claim for Construction Work In Progress as of the end of the Historic Test Year.

The Historic Test Year also includes per books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3, Line 5. Reductions are included for the reserve for depreciation, as provided for by Company witness Spanos (Columbia Statement No. 5), and for gas lost in underground storage on lines 6 and 7, respectively.

Q. Please explain how the Company's Future Test Year and Fully Forecasted Rate Year Property, Plant and Equipment were developed.

A. The Company's Plant in Service as of December 31, 2016 as shown on Exhibit 108, Schedule 1, Column 5 was developed beginning from Column 2 of Page 1 with Gas Plant in Service at November 30, 2014 as also shown on Exhibit 8, Schedule 1. Forecasted capital expenditures from December 2014 through December 2016 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1. Company witness Davidson (Columbia Statement No. 15) provides forecasted plant additions. Forecasted retirements from December 2014 to December 2016, supported by Company witness Spanos (Columbia Statement No. 5) are shown in Exhibit 108, Schedule 1. By adding forecasted capital expenditures and subtracting forecasted retirements, Exhibit 108, Schedule 1 reflects the net forecasted plant in service included in rate base as of December 31, 2016.

Q. Please explain the purpose of Page 2 of Exhibit 8.

A. This page satisfies 52 Pennsylvania Code Section 53.53 I.A, item 2 of the Commission's standard filing requirements, at Exhibit 8, Page 4, that the Company show its rate base claim from its last base rate proceeding.

Q. Please explain why the Contribution in Aid of Construction amounts shown on Exhibit 8, Schedule 1 have not changed from the amount reported in the last base rate case as of test year ended November 30, 2014.

A. Prior to November 2003, the Company recorded plant additions paid through Contribution in Aid of Construction in plant in service (101-1000), with a deduction reflected in contra accounts 101-2000, 101-3000 or 101-4000. Since November

2003, the Company has netted contributions against Plant in Service Account 101-1000, thus, no additional deduction is necessary.

Prior to January 2000, there was no 101-Gas Plant in Service offset for Customer Advances. As such, rate base would not be reduced through Account 101 for Customer Advances prior to January 2000. The reduction to rate base for these Customer Advances is made by including account 252 along with the Deferred Debit in account 186 to offset the post 1999 Customer Advances net in Plant in Service.

Q. Please explain Exhibit 8, Schedule 2.

A. This exhibit reflects the balance in Construction Work in Progress ("CWIP"). The Company is not making a claim for CWIP in the Historic Test Year.

Q. Please explain Exhibit 108, Schedule 2.

A. Exhibit 108, Schedule 2 shows that forecasted CWIP, Account 107, is expected to remain at the same level for the Fully Forecasted Rate Year as it was at November 30, 2014.

Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3, Lines 6 and 7 and Exhibit 108, Page 3, Lines 5 and 6.

A. Line 6, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 5 Exhibit 108 Page 3 for the Fully Forecasted Rate Year were detailed and supplied by Company witness Spanos, by plant account, in Exhibit 5 for the Historic Test Year and Exhibit 105 in the Fully Forecasted Rate Year. Line 7,

Exhibit 8, Page 3 and Line 6, Exhibit 108 Page 3 Accum. Provision Gas Lost – Underground Storage Account 117 is per books as of November 30, 2014 for the Historic Test Year and December 31, 2016 for the Fully Forecasted Rate Year.

Q. Did you include inventory balances in rate base?

A. Yes. As shown on Exhibit 8, Schedule 5, Materials and Supplies included in the historic rate base is a 13 month average of the historical monthly balances in Account 154, 186-99-12357 and 186-99-012980 materials holding clearing accounts. Materials and Supplies in the Fully Forecasted Rate Year rate base and shown on the Exhibit 108, Schedule 5 begins with November and December 2014 actual balances (most recent available), with January 2015 through November 2015 balances calculated by applying the GDP deflator supported by Company witness Miller (Columbia Statement No. 4) in Exhibit 104, Schedule 2, Page 25 to the actual balances of January 2014 through November 2014.

Q. Did you include Prepayment balances in rate base?

A. Yes. Exhibit 8, Schedule 6 for the Historic Test Year and Exhibit 108, Schedule 6 for the Fully Forecasted Rate Year show prepayments for: Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, Office of Consumer's Advocate ("OCA"), and Office of Small Business Advocate ("OSBA"), Account 16503600. The amount in the historic rate base is based on a 13 month average of the historic monthly balances per the Company's books. The amounts for the Fully Forecasted Rate Year rate base were

determined by incrementally applying the GDP Deflators supported by Company witness Miller in Exhibit 104, Schedule 2 page 25 to the January 2014 through November 2014 actual balances to reflect expected new prepayments as of December 2016.

Q. Did you include Gas Stored Underground in rate base?

A. Yes, I did.

Q. What valuation methodology is applied to Gas Stored Underground?

A. As per the Commission's March 31, 2001 Order at Docket No. P-2010-2209925, Columbia uses the Weighted Average Cost of Gas ("WACOG") methodology to value Storage Gas.

Q. Please describe the WACOG accounting methodology you applied to value the Fully Forecasted Rate Year storage balance.

A. Under the WACOG accounting methodology, the actual cost and volume of the current month's injections are added to the inventory value calculated at the end of the previous month, and a new average cost per DTH is calculated for the current month. The current month's withdrawals are deducted from the balance at the new average cost per DTH. When storage gas is being injected (April – October), the inventory cost for the current month is added to the inventory cost from the previous month(s). At the end of injection season, the storage cost for the winter is well established. During the withdrawal season (November – March), withdrawals are made at the average price primarily resulting from injection season.

Q. Did you include an adjustment to Gas Stored Underground in rate base?

A. Yes. I have calculated a twelve month average cost of gas to be included in rate base.

Q. Do you provide exhibits supporting this storage adjustment?

A. Yes, I do.

Q. Please identify and explain those exhibits.

A. The supporting exhibits are Exhibit 8, Schedule 7 and Exhibit 108, Schedule 7. The actual December 2013 through November 2014 injections and withdrawals are reflected on Exhibit 8, Schedule 7 in columns A and E, respectively. A projected monthly average cost of gas is detailed in Column B. Therefore, under WACOG accounting methodology, the current month's injections (Column A) are multiplied by the Monthly Average Cost of Gas (Column B). The result is added to the inventory value calculated at the end of the previous month (Column G), and a new weighted average cost of gas per DTH is calculated (Column D) for the current month. The current month's withdrawals (Column E) are multiplied by the new weighted average cost of gas per DTH (Column D) and the result is deducted from the cumulative balance (Column G). This method is continued every month through November 2014. Line 15 calculates a twelve month average storage balance to be included in the Pro Forma Rate Base.

Exhibit 108, Schedule 7 repeats this process from November 2014 through December 2016. Injection rates are based on those included in the Company's 1307 (f) pre-filing data filed with the Commission on February 27, 2015. Lines 27 and 28

calculate a twelve month average storage balance for the Future Test Year rate base and Fully Forecasted Rate Year, rate base respectively.

Q. Did you include Deferred Income Taxes in rate base?

A. Yes, I did. Balances as of November 30, 2014 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 8, Schedule 8. The balances were supplied by Company witness Fischer (Columbia Statement No. 10) on Exhibit 7, Page 9. Forecasted balances as of November 30, 2015 and December 31, 2016 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 108, Schedule 8. These balances were supplied by Company witness Fischer on Exhibit 107, Pages 5 and 5a.

Q. How did you determine the Customer Deposits in rate base?

A. Customer Deposits, Account 235, is the 13 month historic average, as detailed on Exhibit 8, Schedule 9 for the Historic Test Year. The 13 month average for the forecasted rate base, detailed on Exhibit 108, Schedule 9, reflects projected balances for December 2015 through December 2016, with the entries for November and December of each year based on actual data for November and December of 2014. The balances for the months of January 2016 through October 2016 are the same as the balances in the months of January 2014 through October 2014 following the trend that deposits gradually go up in the winter and down in the summer.

Q. How did you determine the Customer Advances for Construction to be deducted from rate base?

A. The deduction to rate base for Customer Advances is made by including account 252, along with the Deferred Debit in Account 186 to offset the post 1999 Customer Advances net in Plant in Service. As discussed earlier in my testimony, the historic adjustment equals the per books balances at November 30, 2014 as detailed on Exhibit 8, Schedule 10. The future test year and fully forecasted test year adjustments equal the per books balance at December 31, 2014, as detailed on Exhibit 108, Schedule 10.

Q. Does this complete your direct testimony?

A. Yes, it does.

Line No.	Description	Account No.	Plant Beginning Balance 11/30/2013 1/	Additions	Retirements	Balance as of 12/31/2013	Additions	Retirements	Balance as of 1/31/2014
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			Gas Plant in Service						
			$	$	$	$	$	$	$
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	346,039	-	-	346,039	-	-	346,039
5	Intangible Plant, Miscellaneous Software	303.30	8,861,431	900,016	-	9,761,447	131,859	-	9,893,306
					-		-	-	
6	Underground Storage Plant				-		-	-	
7	Land	350.10	23,882	-	-	23,882		-	23,882
8	Rights of Way	350.20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	1,546,676	900,117	-	2,446,793	92,962	-	2,539,756
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
17	Distribution Plant								
18	Land, City Gate/Main Line Industrial	374.10	21,944			21,944			21,944
19	Land, Other Distribution System	374.20	479,552	-	(172)	479,380	-	-	479,380
20	Land Rights, City Gate/Main Line	374.30	95,361	-	-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374.40	1,936,193	75,197	(6)	2,011,384	475	(444)	2,011,415
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,084	22	-	3,233,107			3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026			7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	-	-	4,012			4,012
26	Structures, Regulating	375.40	3,032,142	34,497	-	3,066,639	61,766	(4,366)	3,124,039
27	Structures, Distribution Industrial M&R	375.60	87,670	-	-	87,670	-	-	87,670
28	Structures, Other Distribution System	375.70	4,899,347	12,000	-	4,911,347	1,467	-	4,912,814
29	Structures, Other Distribution System, Leased	375.71	1,148,423	-	(72,298)	1,076,125			1,076,125
30	Structures, Communication	375.80	16,515	-	-	16,515			16,515
31	Mains:								
32	Mains	376.00	769,326,657	10,573,326	(1,732,822)	778,167,161	1,543,154	(180,785)	779,529,531
33	Mains - CSL Replacements	376.08	23,839,553	-	-	23,839,553			23,839,553
34	Bare Steel	376.30	73,235,189	-	(211,567)	73,023,622	-	(39,710)	72,983,912
35	Cast Iron	376.80	600,983	-	(1,267)	599,717			599,717
36	Measuring & Regulating Equipment General	378.10	58,867	-	-	58,867			58,867
37	Measuring & Regulating Equipment Regulating	378.20	19,091,376	1,525,751	(16,444)	20,600,683	271,010	(17,228)	20,854,464
38	Measuring & Regulating Equipment Local Gas	378.30	467,811			467,811	-	-	467,811
39	Measuring & Regulating Equipment City Gate	379.10	147,820	-	-	147,820	-	-	147,820
40	Measuring & Regulating Equipment Exchange Gas	379.11	5,974	-	-	5,974	-	-	5,974
41	Services	380.00	341,349,767	2,700,700	(462,218)	343,588,249	815,882	(319,556)	344,084,575
42	Meters	381.00	33,440,663	54,556	-	33,495,218	62,139	(60,354)	33,497,003
43	Auto Meter Reading Devices	381.10	22,719,385	18	-	22,719,403	-	-	22,719,403
44	Meter Installations	382.00	33,114,881	49,039	(10,687)	33,153,233	97,121	(4,112)	33,246,241
45	House Regulators	383.00	9,806,894	28,690	(492)	9,835,091	57,937	(438)	9,892,590
46	House Regulators Installations	384.00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment, Station Equipment	385.00	4,956,724	3,856	(7,455)	4,953,125	140,253	-	5,093,378
48	Industrial M&R Equipment, Large Volume	385.10	1,250,886	-	(9,578)	1,241,308	-	(14,162)	1,227,146
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	123,756	-	-	123,756	-	-	123,756
52	Other Equipment, Other Communications	387.44	665,089	-	-	665,089	-	-	665,089
53	Other Equipment, Telemetering	387.45	477,309	68,803	-	546,112	97,249	-	643,361
54	Other Equipment, Customer Information Service	387.46	259,436			259,436	-	-	259,436
				-	-		-	-	
55	General Plant			-	-		-	-	
56	Structures, Communications	390.10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,932,006	-	-	2,932,006	-	-	2,932,006
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	1,911,084	299,110	-	2,210,194	-	-	2,210,194
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	204,558	-	(94,406)	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675		-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	-	-	1,774,190	-	-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308		-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	11,337,530	26,770	(8,302)	11,355,997	15,780	-	11,371,777
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,725,639	4,931	(294,546)	1,436,023	(531)	-	1,435,493
72	Communication Equipment	397.00	210,798	-	-	210,798			210,798
73	Communication Equipment, Telephone	397.10	947,979	-	-	947,979			947,979
74	Communication Equipment, Radio	397.20	2,339,889	-	-	2,339,889			2,339,889
75	Communication Equipment, Other	397.40	0		-	0			0
76	Communication Equipment, Telemetering	397.50	856,989	-	-	856,989			856,989
77	Miscellaneous Equipment	398.00	500,697	67,521	-	568,219	(435)	-	567,784
78	Total Gas Plant In Service		1,392,421,741	17,324,918	(2,922,262)	1,406,824,398	3,388,088	(641,155)	1,409,571,331

1/ Exhibit 8, Schedule 1.

Line No.	Description	Account No.	Plant Beginning Balance 1/31/2014	Additions	Retirements	Balance as of 2/28/2014	Additions	Retirements	Balance as of 3/31/2014
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			Gas Plant in Service						
			$	$	$	$	$	$	$
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	346,039	-	-	346,039	-	-	346,039
5	Intangible Plant, Miscellaneous Software	303.30	9,893,306	11,614	(505,566)	9,399,354	62,592	-	9,461,945
								-	
6	Underground Storage Plant							-	
7	Land	350.10	23,882		-	23,882	-	-	23,882
8	Rights of Way	350.20	1,932		-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	2,539,756	(71,150)	-	2,468,606	67,226	-	2,535,831
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
				-	-		-	-	
17	Distribution Plant			-	-		-	-	
18	Land, City Gate/Main Line Industrial	374.10	21,944		-	21,944	-	-	21,944
19	Land, Other Distribution System	374.20	479,380		-	479,380	-	-	479,380
20	Land Rights, City Gate/Main Line	374.30	95,361		-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374.40	2,011,415	5,083	-	2,016,498	-	(1,494)	2,015,004
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,107	0	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	-	-	4,012			4,012
26	Structures, Regulating	375.40	3,124,039	2,488	-	3,126,527	13,716	(16,793)	3,123,451
27	Structures, Distribution Industrial M&R	375.60	87,670	-	-	87,670	-	-	87,670
28	Structures, Other Distribution System	375.70	4,912,814	-	-	4,912,814	-	-	4,912,814
29	Structures, Other Distribution System, Leased	375.71	1,076,125	-	-	1,076,125	-	-	1,076,125
30	Structures, Communication	375.80	16,515	-		16,515			16,515
31	Mains:						-		
32	Mains	376.00	779,529,531	5,061,816	(143,735)	784,447,612	6,835,913	(226,166)	791,057,359
33	Mains - CSL Replacements	376.08	23,839,553		-	23,839,553	-	-	23,839,553
34	Bare Steel	376.30	72,983,912	-	21,134	73,005,047	(1,492,885)	(39,123)	71,473,039
35	Cast Iron	376.80	599,717	-	(1,631)	598,086		(6,325)	591,761
36	Measuring & Regulating Equipment General	378.10	58,867		-	58,867	-	-	58,867
37	Measuring & Regulating Equipment Regulating	378.20	20,854,464	(16,686)	(4,697)	20,833,082	35,829	(54,375)	20,814,535
38	Measuring & Regulating Equipment Local Gas	378.30	467,811	-	(3,337)	464,474	-	-	464,474
39	Measuring & Regulating Equipment City Gate	379.10	147,820	-	-	147,820		(1,808)	146,012
40	Measuring & Regulating Equipment Exchange Gas	379.11	5,974		-	5,974		-	5,974
41	Services	380.00	344,084,575	1,987,239	(209,165)	345,862,649	3,414,741	(208,710)	349,068,680
42	Meters	381.00	33,497,003	94,476	-	33,591,479	60,647	(31,824)	33,620,302
43	Auto Meter Reading Devices	381.10	22,719,403	-	-	22,719,403	-	-	22,719,403
44	Meter Installations	382.00	33,246,241	42,982	(19,064)	33,270,159	61,788	(5,139)	33,326,808
45	House Regulators	383.00	9,892,590	37,120	(580)	9,929,131	30,109	(483)	9,958,757
46	House Regulators Installations	384.00	3,864,772		-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment, Station Equipment	385.00	5,093,378	54,814	-	5,148,193	2,028	(17,679)	5,132,541
48	Industrial M&R Equipment, Large Volume	385.10	1,227,146	-	-	1,227,146	-	(591)	1,226,556
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	123,756	-	-	123,756	-	-	123,756
52	Other Equipment, Other Communications	387.44	665,089	-	-	665,089	-	-	665,089
53	Other Equipment, Telemetering	387.45	643,361	24,924	-	668,284	1,050	-	669,334
54	Other Equipment, Customer Information Service	387.46	259,436	-	-	259,436	-	-	259,436
							-	-	
55	General Plant						-	-	
56	Structures, Communications	390.10	49,821	-	-	49,821		-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,932,006	-	-	2,932,006	-	-	2,932,006
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,210,194	-	-	2,210,194	(12,300)	-	2,197,893
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	-	-	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	-	-	1,774,190		-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308	-	-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	11,371,777	29,016	-	11,400,793	55,068	-	11,455,862
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397.00	210,798	-	-	210,798	-	-	210,798
73	Communication Equipment, Telephone	397.10	947,979	-	-	947,979	-	-	947,979
74	Communication Equipment, Radio	397.20	2,339,889	-		2,339,889	-	-	2,339,889
75	Communication Equipment, Other	397.40	0			0	-	-	0
76	Communication Equipment, Telemetering	397.50	856,989	-	-	856,989	-	-	856,989
77	Miscellaneous Equipment	398.00	567,784	-	-	567,784	-	-	567,784
78	Total Gas Plant in Service		1,409,571,331	7,263,737	(866,639)	1,415,968,429	9,135,521	(610,510)	1,424,493,440

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 3/31/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2014 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2014 (8)=(5+6+7) $
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	346,039	-	-	346,039	-	-	346,039
5	Intangible Plant, Miscellaneous Software	303.30	9,461,945	7,569,964	(466,558)	16,565,351	173,127	-	16,738,478
6	Underground Storage Plant								
7	Land	350.10	23,882	-	-	23,882	-	-	23,882
8	Rights of Way	350.20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	2,535,831	-	-	2,535,831	841,250	-	3,377,081
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
17	Distribution Plant			-	-				
18	Land, City Gate/Main Line Industrial	374.10	21,944	-	-	21,944	-	-	21,944
19	Land, Other Distribution System	374.20	479,380	-	-	479,380	-	-	479,380
20	Land Rights, City Gate/Main Line	374.30	95,361	-	-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374.40	2,015,004	6	(20)	2,014,989	82,513	(7,615)	2,089,888
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,107	-	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	-	-	4,012			4,012
26	Structures, Regulating	375.40	3,123,451	46,841	(4,626)	3,165,666	95,762	(3,095)	3,258,333
27	Structures, Distribution Industrial M&R	375.60	87,670	-	-	87,670			87,670
28	Structures, Other Distribution System	375.70	4,912,814	-	-	4,912,814	1,886	-	4,914,700
29	Structures, Other Distribution System, Leased	375.71	1,076,125	-	-	1,076,125	-	-	1,076,125
30	Structures, Communication	375.80	16,515	-	-	16,515			16,515
31	Mains:								
32	Mains	376.00	791,057,359	14,355,285	(420,438)	804,992,206	16,924,582	(472,826)	821,443,963
33	Mains - CSL Replacements	376.08	23,839,553	-	-	23,839,553	-	-	23,839,553
34	Bare Steel	376.30	71,473,039	-	(68,880)	71,404,159	-	(127,828)	71,276,331
35	Cast Iron	376.80	591,761	-	(1,438)	590,324	-	(1,563)	588,761
36	Measuring & Regulating Equipment General	378.10	58,867	-	-	58,867	-	-	58,867
37	Measuring & Regulating Equipment Regulating	378.20	20,814,535	86,962	(4,380)	20,897,118	323,095	(6,701)	21,213,512
38	Measuring & Regulating Equipment Local Gas	378.30	464,474	-	(742)	463,732	-	-	463,732
39	Measuring & Regulating Equipment City Gate	379.10	146,012	-	-	146,012	-	-	146,012
40	Measuring & Regulating Equipment Exchange Gas	379.11	5,974	-	-	5,974	-	-	5,974
41	Services	380.00	349,068,680	5,598,064	(511,026)	354,155,718	4,498,427	(536,213)	358,117,932
42	Meters	381.00	33,620,302	69,880	(15,318)	33,674,864	104,246	(27,348)	33,751,762
43	Auto Meter Reading Devices	381.10	22,719,403	-	-	22,719,403	-	-	22,719,403
44	Meter Installations	382.00	33,326,808	80,790	(6,810)	33,400,788	77,657	(8,559)	33,469,885
45	House Regulators	383.00	9,958,757	68,927	(466)	10,027,218	24,162	(1,079)	10,050,301
46	House Regulators Installations	384.00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	5,132,541	14,388	(56,168)	5,090,762	462	(2,359)	5,088,865
48	Industrial M&R Equipment. Large Volume	385.10	1,226,556	-	(5,875)	1,220,681	-	(4,021)	1,216,660
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	123,756		-	123,756	-	-	123,756
52	Other Equipment, Other Communications	387.44	665,089	-	-	665,089	-	(8,175)	656,915
53	Other Equipment, Telemetering	387.45	669,334	6,369	-	675,703	151,316	(6,804)	820,215
54	Other Equipment, Customer Information Service	387.46	259,436	-	-	259,436	-	-	259,436
55	General Plant		0						
56	Structures, Communications	390.10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,932,006	-	-	2,932,006	-	-	2,932,006
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,197,893	-	-	2,197,893	-	-	2,197,893
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	-	-	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190		-	1,774,190	-	-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308	-	-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	11,455,862	70,644	-	11,526,506	38,059	-	11,564,565
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397.00	210,798	-	-	210,798	-	-	210,798
73	Communication Equipment, Telephone	397.10	947,979	-	-	947,979	-	-	947,979
74	Communication Equipment, Radio	397.20	2,339,889	-	-	2,339,889	-	-	2,339,889
75	Communication Equipment, Other	397.40	0			0			0
76	Communication Equipment, Telemetering	397.50	856,989			856,989	127,767	(8,153)	976,603
77	Miscellaneous Equipment	398.00	567,784	-	-	567,784	-	-	567,784
78	Total Gas Plant in Service		1,424,493,440	27,968,120	(1,562,743)	1,450,898,816	23,464,309	(1,222,338)	1,473,140,787

Line No.	Description	Account No. (1)	Plant Beginning Balance 5/31/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2014 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2014 (8)=(5+6+7) $
			Gas Plant in Service						
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	346,039	-	-	346,039	-	-	346,039
5	Intangible Plant, Miscellaneous Software	303.30	16,738,478	253,798	-	16,992,276	75,086	(284,876)	16,782,485
6	Underground Storage Plant								
7	Land	350.10	23,882	-	-	23,882	-	-	23,882
8	Rights of Way	350.20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	3,377,081	-	-	3,377,081	1,486	-	3,378,567
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
17	Distribution Plant			-	-				
18	Land, City Gate/Main Line Industrial	374.10	21,944	-	-	21,944	-		21,944
19	Land, Other Distribution System	374.20	479,380	-	-	479,380	-	(14)	479,366
20	Land Rights, City Gate/Main Line	374.30	95,361		-	95,361	-		95,361
21	Land Rights, City Other Distribution System	374.40	2,089,888	31,339	-	2,121,227	-	(11,093)	2,110,134
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,107	-	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012			4,012			4,012
26	Structures, Regulating	375.40	3,258,333	16,231	(13,572)	3,260,993	36,911	(1,036)	3,296,868
27	Structures, Distribution Industrial M&R	375.60	87,670		-	87,670	-	-	87,670
28	Structures, Other Distribution System	375.70	4,914,700	74,042	-	4,988,742	58,607	-	5,047,350
29	Structures, Other Distribution System, Leased	375.71	1,076,125	49,701	-	1,125,826	-	-	1,125,826
30	Structures, Communication	375.80	16,515			16,515	-	-	16,515
31	Mains:								
32	Mains	376.00	821,443,963	21,923,289	(355,537)	843,011,715	6,599,916	(150,927)	849,460,703
33	Mains - CSL Replacements	376.08	23,839,553	-	-	23,839,553	-	-	23,839,553
34	Bare Steel	376.30	71,276,331	-	(120,895)	71,155,436	7,581	(20,452)	71,142,565
35	Cast Iron	376.80	588,761		(157)	588,603	-	(1,366)	587,237
36	Measuring & Regulating Equipment General	378.10	58,867	-	-	58,867	-	-	58,867
37	Measuring & Regulating Equipment Regulating	378.20	21,213,512	900,118	(132,584)	21,981,046	646,816	(72,295)	22,555,567
38	Measuring & Regulating Equipment Local Gas	378.30	463,732			463,732	-	-	463,732
39	Measuring & Regulating Equipment City Gate	379.10	146,012			146,012	-	-	146,012
40	Measuring & Regulating Equipment Exchange Gas	379.11	5,974	-	(6,424)	(450)	-	-	(450)
41	Services	380.00	358,117,932	6,621,291	(459,074)	364,280,148	3,621,192	(591,662)	367,309,679
42	Meters	381.00	33,751,762	43,531	(45,260)	33,750,032	38,745	(66,770)	33,722,007
43	Auto Meter Reading Devices	381.10	22,719,403	-	-	22,719,403	-	-	22,719,403
44	Meter Installations	382.00	33,469,885	68,606	(6,990)	33,531,501	180,364	(18,107)	33,693,758
45	House Regulators	383.00	10,050,301	31,784	(767)	10,081,318	56,065	(584)	10,136,799
46	House Regulators Installations	384.00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	5,088,865	2,900	(10,720)	5,081,046	-	(21,634)	5,059,412
48	Industrial M&R Equipment. Large Volume	385.10	1,216,660	-	(3,399)	1,213,260	-	(9,663)	1,203,598
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	123,756	-	(1,811)	121,945	-	-	121,945
52	Other Equipment, Other Communications	387.44	656,915	-	(910)	656,004	-	-	656,004
53	Other Equipment, Telemetering	387.45	820,215	501,433	(3,850)	1,317,798	2,744	-	1,320,542
54	Other Equipment, Customer Information Service	387.46	259,436	-	-	259,436	-	-	259,436
55	General Plant								
56	Structures, Communications	390.10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,932,006	-	-	2,932,006	12,315	-	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,197,893	-	-	2,197,893	-	-	2,197,893
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	-	-	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	-	-	1,774,190		-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308	-	-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	11,564,565	291,514	-	11,856,079	104,715	-	11,960,794
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397.00	210,798	-		210,798	-	-	210,798
73	Communication Equipment, Telephone	397.10	947,979		-	947,979		-	947,979
74	Communication Equipment, Radio	397.20	2,339,889	-	-	2,339,889	-	-	2,339,889
75	Communication Equipment, Other	397.40	0			0			0
76	Communication Equipment, Telemetering	397.50	976,603	-	(20,613)	955,990	-	-	955,990
77	Miscellaneous Equipment	398.00	567,784	35,619	-	603,403	(58,607)	-	544,795
78	Total Gas Plant in Service		1,473,140,787	30,845,196	(1,182,562)	1,502,803,422	11,383,938	(1,250,479)	1,512,936,881

Line No.	Description	Account No. (1)	Plant Beginning Balance 7/31/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 8/31/2014 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 9/30/2014 (8)=(5+6+7) $
			Gas Plant in Service						
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	346,039	974,556	-	1,320,595	-	-	1,320,595
5	Intangible Plant, Miscellaneous Software	303.30	16,782,485	26,986	-	16,809,471	51,595	-	16,861,066
6	Underground Storage Plant								
7	Land	350.10	23,882	-	-	23,882	-	-	23,882
8	Rights of Way	350.20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	3,378,567	34,537	-	3,413,104	-	-	3,413,104
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
17	Distribution Plant								
18	Land, City Gate/Main Line Industrial	374.10	21,944	-	-	21,944	-	-	21,944
19	Land, Other Distribution System	374.20	479,366	-	-	479,366	-	-	479,366
20	Land Rights, City Gate/Main Line	374.30	95,361	-	-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374.40	2,110,134	9,981	-	2,120,114	9,942	(2,135)	2,127,921
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,107	-	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	-	-	4,012	-	-	4,012
26	Structures, Regulating	375.40	3,296,868	22,637	-	3,319,505	22,965	(5,008)	3,337,462
27	Structures, Distribution Industrial M&R	375.60	87,670	-	-	87,670	-	-	87,670
28	Structures, Other Distribution System	375.70	5,047,350	-	-	5,047,350	-	-	5,047,350
29	Structures, Other Distribution System, Leased	375.71	1,125,826	-	-	1,125,826	-	-	1,125,826
30	Structures, Communication	375.80	16,515	-	-	16,515	-	-	16,515
31	Mains:								
32	Mains	376.00	849,460,703	8,939,065	(235,617)	858,164,152	8,419,628	(643,426)	865,940,354
33	Mains - CSL Replacements	376.08	23,839,553	-	-	23,839,553	-	-	23,839,553
34	Bare Steel	376.30	71,142,565	(4,453)	(76,793)	71,061,319	-	(159,618)	70,901,702
35	Cast Iron	376.80	587,237	-	-	587,237	-	-	587,237
36	Measuring & Regulating Equipment General	378.10	58,867	-	-	58,867	-	(2,414)	56,453
37	Measuring & Regulating Equipment Regulating	378.20	22,555,567	588,158	(8,192)	23,135,532	471,334	(27,917)	23,578,950
38	Measuring & Regulating Equipment Local Gas	378.30	463,732	-	-	463,732	-	(6,451)	457,281
39	Measuring & Regulating Equipment City Gate	379.10	146,012	-	-	146,012	-	-	146,012
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	-	-	(450)	-	-	(450)
41	Services	380.00	367,309,679	6,065,365	(770,125)	372,604,919	4,645,793	(834,221)	376,416,491
42	Meters	381.00	33,722,007	194,174	(23,391)	33,892,790	97,114	(31,310)	33,958,594
43	Auto Meter Reading Devices	381.10	22,719,403	209,073	-	22,928,475	-	-	22,928,475
44	Meter Installations	382.00	33,693,758	107,500	(7,356)	33,793,902	192,493	(7,782)	33,978,613
45	House Regulators	383.00	10,136,799	121,102	(818)	10,257,084	74,883	(802)	10,331,165
46	House Regulators Installations	384.00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment, Station Equipment	385.00	5,059,412	2,076	(17,267)	5,044,221	3,518	(19,357)	5,028,382
48	Industrial M&R Equipment, Large Volume	385.10	1,203,598	-	(4,336)	1,199,262	-	-	1,199,262
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	121,945	-	-	121,945	-	-	121,945
52	Other Equipment, Other Communications	387.44	656,004	-	-	656,004	26	-	656,030
53	Other Equipment, Telemetering	387.45	1,320,542	19,527	-	1,340,069	27,953	(6,131)	1,361,891
54	Other Equipment, Customer Information Service	387.46	259,436	-	-	259,436	-	-	259,436
55	General Plant								
56	Structures, Communications	390.10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,944,321	-	-	2,944,321	-	-	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,197,893	-	-	2,197,893	-	-	2,197,893
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	-	-	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	-	-	1,774,190	-	-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308	-	-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	11,960,794	87,503	-	12,048,297	90,327	-	12,138,624
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397.00	210,798	-	-	210,798	-	-	210,798
73	Communication Equipment, Telephone	397.10	947,979	-	-	947,979	-	-	947,979
74	Communication Equipment, Radio	397.20	2,339,889	-	-	2,339,889	-	-	2,339,889
75	Communication Equipment, Other	397.40	0	-	-	0	-	-	0
76	Communication Equipment, Telemetering	397.50	955,990	-	-	955,990	-	-	955,990
77	Miscellaneous Equipment	398.00	544,795	25,976	-	570,771	-	-	570,771
78	Total Gas Plant In Service		1,512,936,881	17,423,763	(1,143,895)	1,529,216,748	14,107,571	(1,746,571)	1,541,577,748

Line No.	Description	Account No. (1)	Plant Beginning Balance 9/30/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 10/31/2014 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 11/30/2014 (8)=(5+6+7) $
			Gas Plant in Service						
1	Intangible Plant								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303.00	1,320,595	-	-	1,320,595	-	-	1,320,595
5	Intangible Plant, Miscellaneous Software	303.30	16,861,066	75,780	-	16,936,846	56,692	-	16,993,538
6	Underground Storage Plant								
7	Land	350.10	23,882	-	-	23,882	-	-	23,882
8	Rights of Way	350.20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351.20	3,413,104	872	-	3,413,976	(142)	-	3,413,834
10	Wells Construction	352.01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352.02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352.10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352.12	67,498	-	-	67,498	-	-	67,498
14	Lines	353.00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354.00	584,073	-	-	584,073	-	-	584,073
16	Measuring & Regulating Equipment	355.00	123,010	-	-	123,010	-	-	123,010
17	Distribution Plant								
18	Land, City Gate/Main Line Industrial	374.10	21,944	-	-	21,944	-	-	21,944
19	Land, Other Distribution System	374.20	479,366	-	(91)	479,275	-	-	479,275
20	Land Rights, City Gate/Main Line	374.30	95,361	-	-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374.40	2,127,921	-	(68)	2,127,853	929	-	2,128,782
22	Land Rights, City Other Distribution System, Loc	374.41	13	-	-	13	-	-	13
23	Rights of Way	374.50	3,233,107	-	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375.20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	-	-	4,012	-	-	4,012
26	Structures, Regulating	375.40	3,337,462	4,182	(9,134)	3,332,510	15,413	-	3,347,923
27	Structures, Distribution Industrial M&R	375.60	87,670	-	-	87,670	-	-	87,670
28	Structures, Other Distribution System	375.70	5,047,350	13,234	-	5,060,584	255	-	5,060,838
29	Structures, Other Distribution System, Leased	375.71	1,125,826	-	-	1,125,826	84	-	1,125,911
30	Structures, Communication	375.80	16,515	-	-	16,515	-	-	16,515
31	Mains:								
32	Mains	376.00	865,940,354	11,624,285	(925,555)	876,639,084	13,694,175	(622,420)	889,710,839
33	Mains - CSL Replacements	376.08	23,839,553	-	-	23,839,553	-	-	23,839,553
34	Bare Steel	376.30	70,901,702	18,274	(95,879)	70,824,097	(3,618)	(201,498)	70,618,980
35	Cast Iron	376.60	587,237	-	(12,753)	574,484	-	(3,884)	570,600
36	Measuring & Regulating Equipment General	378.10	56,453	-	-	56,453	-	-	56,453
37	Measuring & Regulating Equipment Regulating	378.20	23,578,950	1,892,384	(58,576)	25,412,758	3,841,347	(3,683)	29,250,421
38	Measuring & Regulating Equipment Local Gas	378.30	457,281	-	-	457,281	-	-	457,281
39	Measuring & Regulating Equipment City Gate	379.10	146,012	-	(4,445)	141,567	-	-	141,567
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	-	-	(450)	-	-	(450)
41	Services	380.00	376,416,491	6,163,900	(695,590)	381,884,801	5,968,690	(655,394)	387,198,097
42	Meters	381.00	33,958,594	123,447	(61,751)	34,020,290	102,856	-	34,123,146
43	Auto Meter Reading Devices	381.10	22,928,475	-	-	22,928,475	-	-	22,928,475
44	Meter Installations	382.00	33,978,613	165,393	(8,820)	34,135,186	59,187	(9,548)	34,184,825
45	House Regulators	383.00	10,331,165	50,708	(914)	10,380,959	50,571	(762)	10,430,768
46	House Regulators Installations	384.00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	5,028,382	13,583	(23,434)	5,018,531	512,235	(4,570)	5,526,196
48	Industrial M&R Equipment. Large Volume	385.10	1,199,262	-	(5,468)	1,193,794	-	(3,803)	1,189,991
49	Other Equipment	387.10	16,603	-	-	16,603	-	-	16,603
50	Other Equipment, Odorization	387.20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387.42	121,945	-	-	121,945	-	-	121,945
52	Other Equipment, Other Communications	387.44	656,030	(26)	-	656,004	-	-	656,004
53	Other Equipment, Telemetering	387.45	1,361,891	10,461	-	1,372,352	715,514	-	2,087,866
54	Other Equipment, Customer Information Service	387.46	259,436	-	-	259,436	-	-	259,436
55	General Plant								
56	Structures, Communications	390.10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,944,321	-	-	2,944,321	-	-	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	-	-	49,805	-	-	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,197,893	-	-	2,197,893	-	-	2,197,893
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	-	-	110,152	-	-	110,152
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	-	-	10,830	-	-	10,830
63	Stores Equipment	393.00	16,675	-	-	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	-	-	122,964	-	-	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	-	-	1,774,190	-	-	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	-	-	179,308	-	-	179,308
67	Tools, Shop Equipment	394.20	72,307	-	-	72,307	-	-	72,307
68	Tools, Tools and Other	394.30	12,138,624	11,529	-	12,150,153	30,900	-	12,181,053
69	Tools, High Pressure Stopping	394.31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395.00	72,218	-	-	72,218	-	-	72,218
71	Power Operated Equipment	396.00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397.00	210,798	-	-	210,798	-	-	210,798
73	Communication Equipment, Telephone	397.10	947,979	-	(593,833)	354,146	-	(11,840)	342,306
74	Communication Equipment, Radio	397.20	2,339,889	-	-	2,339,889	-	-	2,339,889
75	Communication Equipment, Other	397.40	0	-	-	0	-	-	0
76	Communication Equipment, Telemetering	397.50	955,990	-	-	955,990	(127,767)	-	828,223
77	Miscellaneous Equipment	398.00	570,771	-	-	570,771	-	-	570,771
78	Total Gas Plant in Service		1,541,577,748	20,168,006	(2,496,311)	1,559,249,443	24,917,322	(1,517,403)	1,582,649,362

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 11/30/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2014 (5 = 2+3+4) $
1	Intangible Plant					
2	Organization Costs	301.00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	0	0	26,489
4	Intangible Plant, General	303.00	1,320,595	0	0	1,320,595
5	Intangible Plant, Miscellaneous Software	303.30	16,993,538	120,856	0	17,114,395
6	Underground Storage Plant					
7	Land	350.10	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,413,834	(282,755)	0	3,131,079
10	Wells Construction	352.01	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498
14	Lines	353.00	405,288	0	0	405,288
15	Compressor Station Equipment	354.00	584,073	280,679	0	864,752
16	Measuring & Regulating Equipment	355.00	123,010	0	0	123,010
17	Distribution Plant					
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	479,275	0	0	479,275
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,128,782	0	(1,546)	2,127,237
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
23	Rights of Way	374.50	3,233,107	0	0	3,233,107
24		375.20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
26	Structures, Regulating	375.40	3,347,923	46,650	(2,096)	3,392,478
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	5,060,838	769,881	0	5,830,720
29	Structures, Other Distribution System, Leased	375.71	1,125,911	0	0	1,125,911
30	Structures, Communication	375.80	16,515	0	0	16,515
31	Mains:					
32	Mains	376.00	889,710,839	21,239,463	(2,159,023)	908,791,279
33	Mains - CSL Replacements	376.08	23,839,553	0	0	23,839,553
34	Bare Steel	376.30	70,618,980	0	(384,489)	70,234,491
35	Cast Iron	376.80	570,600	0	(6,151)	564,449
36	Measuring & Regulating Equipment General	378.10	56,453	0	0	56,453
37	Measuring & Regulating Equipment Regulating	378.20	29,250,421	1,527,163	(29,750)	30,747,835
38	Measuring & Regulating Equipment Local Gas	378.30	457,281	0	0	457,281
39	Measuring & Regulating Equipment City Gate	379.10	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
41	Services	380.00	387,198,097	(11,171,298)	(352,261)	375,674,538
42	Meters	381.00	34,123,146	200,454	(29,918)	34,293,681
43	Auto Meter Reading Devices	381.10	22,928,475	97,733	0	23,026,208
44	Meter Installations	382.00	34,184,825	94,382	(4,715)	34,274,492
45	House Regulators	383.00	10,430,768	48,942	(441)	10,479,269
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment, Station Equipment	385.00	5,526,196	9,945	(6,252)	5,529,890
48	Industrial M&R Equipment, Large Volume	385.10	1,189,991	0	(1,435)	1,188,556
49	Other Equipment	387.10	16,603	0	0	16,603
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	121,945	0	0	121,945
52	Other Equipment, Other Communications	387.44	656,004	175	0	656,179
53	Other Equipment, Telemetering	387.45	2,087,866	105,441	0	2,193,308
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	General Plant					
56	Structures, Communications	390.10	49,821	0	0	49,821
57	Office Furniture & Equipment, Unspecified	391.10	2,944,321	0	0	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391.11	49,805	0	0	49,805
59	Office Furniture & Equipment, Information Systems	391.12	2,197,893	195,007	0	2,392,901
60	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
61	Transportation Equipment, Trailers > $1,000	392.20	110,152	0	(10,545)	99,607
62	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
63	Stores Equipment	393.00	16,675	0	0	16,675
64	Tools, Garage & Service Equipment	394.10	122,964	0	0	122,964
65	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190
66	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
67	Tools, Shop Equipment	394.20	72,307	0	0	72,307
68	Tools, Tools and Other	394.30	12,181,053	65,715	0	12,246,768
69	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
70	Laboratory Equipment Gas	395.00	72,218	0	0	72,218
71	Power Operated Equipment	396.00	1,435,493	0	0	1,435,493
72	Communication Equipment	397.00	210,798	0	0	210,798
73	Communication Equipment, Telephone	397.10	342,306	0	0	342,306
74	Communication Equipment, Radio	397.20	2,339,889	0	0	2,339,889
75	Communication Equipment, Other	397.40	0	0	0	0
76	Communication Equipment, Telemetering	397.50	828,223	0	0	828,223
77	Miscellaneous Equipment	398.00	570,771	0	0	570,771
78	Total Gas Plant in Service		1,582,649,362	13,348,436	(2,988,622)	1,593,009,176

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
BRIAN E. ELLIOTT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Q. Please state your name and business address.

A. Brian E. Elliott, 290 W. Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"). My title is Manager for Regulatory Strategy & Support.

Q. What is your educational background?

A. I graduated from West Virginia State College in 1985 with a Bachelor of Science degree in Business Administration and I majored in Accounting. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. Please briefly describe your professional experience.

A. In March 1991, I joined Columbia Natural Resources ("CNR"). From 1991 until 2001, I held several positions of increasing responsibility in the Finance Department of CNR. In 1997, I was promoted to Financial Planning Manager. In 2001, I changed roles to become the Accounting Manager of CNR. From mid-2002 through 2003, I assumed a role with NCSC as the Financial Planning Manager of a group of regulated utilities, including Columbia Gas of Ohio, Columbia Gas of Kentucky, and Bay State Gas Company (now dba Columbia Gas of Massachusetts). From 2004 through mid-2012, I was the Accounting Manager of Columbia Gas of Ohio. Most recently, in mid-2012, I accepted my current position as a manager in NCSC's Regulatory Strategy & Support Department,

providing support to companies in NiSource Inc.'s gas distribution segment, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Have you previously testified before the Pennsylvania Public Utility Commission or any other regulatory commission?

A. Yes, I presented testimony in Columbia's last rate case at Docket No. R-2014-24062714. Additionally, I have testified before the Public Service Commission of Maryland, the Massachusetts Department of Public Utilities, and the Virginia State Corporation Commission.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring Columbia's Allocated Cost of Service ("ACOS") studies in this matter. As required by Section 53.53 III, Items 1 and 9 of the Commission's regulations, I prepared ACOS studies by rate class at present and proposed rates (Item 1) and a cost analysis supporting minimum charges for all rate schedules (Item 9). The studies and cost analysis are presented in Exhibit 111. Item 10 of Section 53.53 III requires a cost analysis supporting demand charges. However, I did not prepare this analysis because Columbia's present and proposed tariffs do not contain distribution demand charges.

Q. Please describe Exhibit No. 11.

A. Exhibit No. 11 addresses the Commission's filing requirements regarding ACOS studies and rate design as required by Section 53.53 III. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the

methodologies are included in this testimony. The ACOS studies are based on the fully forecasted rate year ending December 31, 2016.

Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?

A. Yes, I am.

Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?

A. Yes.

Q. Why did you conduct three ACOS studies?

A. Columbia has filed two studies in its base rate proceedings since the early nineteen-eighties that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class while the peak & average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia recognizes that no one cost of service study is the "right" study and in the past believed the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates.

Q. What is the basis of the third study and why did Columbia file it?

A. The third study as presented in Exhibit No. 111, Schedule 3 is an average of the customer-demand study and the peak and average study. Columbia continues to believe that the customer-demand study and the peak and average study provide a reasonable range, and the average study with its equal weighting of the two provides the Company, the parties and the Commission with a set of returns that

can be used as a benchmark or guide in revenue allocation. It is another tool that is used in setting rates based on the cost to serve.

Q. Could you provide a list of the schedules, and attachments you are sponsoring through your testimony?

A. Yes. The table below lists all the schedules, and attachments that I am sponsoring.

Schedule/Attachment	**Description**
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak & Average Study
Exh. No. 111, Schedule No. 3	Average Study
Exh, No. 111, Schedule No. 4	List of Allocation Factors
Statement No. 7, Exhibit BEE-1	Development of Allocation Factors
Statement No. 7, Exhibit BEE-2	Development of Allocation Factors Factor Nos. 5, 20 and 22
Statement No. 7, Exhibit BEE-3	Factor Selection and Rationale
Statement No. 7, Exhibit BEE-4	Intra-Class Adjustment of Storage Carrying Costs

Q. Could you briefly describe the format of the ACOS studies that you are sponsoring?

A. The format is substantially similar for the three studies except for the customer-demand study, Schedule No. 1. It contains 18 pages while the Peak and Average study in Schedule 2 and the Average study in Schedule 3 contain 13 pages. The Customer-Demand study contains the system charge studies, which I will be discussing later in my testimony, on pages 14 through 18 of Exhibit 111, Schedule No. 1. The rates of return that are shown on page 1 of each study are based on

income that is generated using proposed rates, with page 2 showing the rates of return that are generated using current rates. Both page 1 and page 2 summarize the same allocated cost of service with the exception of income taxes and uncollectibles, which vary with the changes in revenue as a result of the change in current rates to proposed rates. The allocation of gross plant investment is shown on page 3 while page 4 contains the reserve for depreciation and page 5 contains depreciation and amortization expenses. Revenue by account and rate schedule is summarized on page 6 for both current and proposed rates and pages 7 and 8 contain the allocation for operation and maintenance expenses, while page 9 contains the allocation of taxes other than income. Rate base is detailed by rate schedule on page 10, with page 11 calculating Federal and Corporate Net Income taxes. The allocation factors are listed on pages 12 and 13. As noted above, a summary of the rates of return by rate schedule is provided in Exhibit BEE-1.

Q. How were the rate schedules grouped in allocating the cost of service?

A. For residential and small general service, sales and delivery services were combined, respectively; Residential Sales Service ("RSS") and Residential Distribution Service ("RDS") were combined and presented in Column D of each study, and Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD") and Small General Distribution Service ("SGDS") were combined and presented in Column E of each study. Because essentially any customer can qualify and, therefore, switch between sales and distribution services under these schedules, it is reasonable to conclude that customer characteristics are the same

for both types of services, i.e., size, consumption patterns, heat sensitive, human need requirement, etc. With no long term difference in the customers' profiles, the distribution cost to provide such service is equivalent. For the larger customers, the studies present the cost of service for each rate schedule: Small Distribution Service and the lower band of Large General Sales Service ("SDS/LGSS") is presented in Column G, and Large Distribution Service and the upper band of Large General Sales Service ("LDS/LGSS") is presented in Column H. Main Line Sales Service ("MLS") and Main Line Distribution Service ("MLDS") are combined and presented in Column I due to their unique characteristic of proximity to an interstate pipeline. Column F, which previously included the Large General Sales Service ("LGSS"), is now marked "N/A" in this study as the LGSS customers who were previously included here have been split between and combined with either the existing SDS or LDS classes of customers, as shown in Columns G and H, respectively.[1]

Q. What method did Columbia use in previous cases to identify and separate Account 376 – Mains before allocation to the rate classes in each study?

A. Before its 2012 rate case (Docket No. R-2012-2321748), Columbia did not identify and separate mains before applying allocation factors. In its 2012 rate case, Columbia identified and separated mains (excluding mains directly assigned to the MLS/MLDS class) by separating that portion of mains that can

[1] The merging of LGS base rate charges with the base rate charges of the SDS and LDS rate classes is addressed in Company Witness Balmert's testimony, Statement 11, Section III.

only serve residential and SGS/SGDS customers ("small customer mains") and that portion of mains that can be used to serve all customers. By separating the low pressure and two inch mains and allocating those mains to only the residential and SGS/SGDS class, Columbia recognized that the remaining rate classes were not physically served from those systems, did not benefit from those systems, and therefore should not share in the recovery of those systems' costs. The remaining intermediate pressure ("IP"), medium pressure ("MP") and high pressure ("HP") systems greater than two inches may or may not be required to serve those customers who are served directly from a low pressure system. Without a detailed analysis of each of Columbia's IP, MP, and HP systems the Company did not know which customers were served from those systems and, therefore, Columbia allocated the IP, MP, and HP systems, as it had in previous rate cases, to all rate classes except the MLS/MLDS class. In its 2014 rate case (Docket No. R-2014-2406274), Columbia performed a detailed analysis of each of its IP, MP, and HP systems, in order to allocate the cost of those systems to the customers who used them.

Q. Have you again performed a detailed analysis of each of Columbia's IP, MP, and HP systems in this case?

A. No. A significant investment in time was made in the 2014 rate case to develop the engineering studies and analysis of the IP, MP, and HP systems. Because Columbia believes that the impact of one year of capital activity would likely not have a significant impact on the results of a new study, Columbia is relying on the

modified results of its analysis of the IP, MP, and HP systems that were used in the 2014 case. In that prior case, a detailed analysis of each of the Company's IP, MP, and HP systems was performed, resulting in a refined mains allocation method. In its current case, Columbia, after identifying and directly assigning the actual inventory of mains for the MLS/MLDS rate class, is again assigning its remaining mains to one of four allocation categories: 'transmission', 'low pressure', 'regulated non-low pressure', and 'remaining regulated pressure.' Each of these groupings of mains is then being separately allocated using Columbia's traditional allocation methods.

Q. Did Columbia make any changes to the 2014 mains study for the purpose of its current rate case?

A. Yes. Short of preparing a completely new engineering study, Columbia updated as many factors as possible in the 2014 study. As described elsewhere in my testimony, we are preparing multiple Allocated Cost of Service Studies. Two of those are the Customer/Demand Study and the Peak and Average Study. In the Customer/Demand Study, the primary drivers of the allocation of the cost of mains are customer counts and design day demand. For each of those drivers, Columbia updated the study to reflect the 2015 rate case data. Similarly, in the Peak and Average Study, the primary drivers of the allocation of the cost of mains are average throughput and design day demand. As with the Customer/Demand Study, Columbia updated these two drivers to reflect the 2015 rate case data.

Additionally, because Columbia was replacing steel pipe with plastic pipe throughout the year, we recognized that the total quantities of kind and size of pipe had changed. To recognize this fact and include this impact in the mains study, Columbia compared the quantities, from its 2014 rate case mains study, of each size/kind combination of plastic and steel pipe, to the quantities of each size/kind combination of plastic and steel pipe identified in its current case. Wherever this comparison produced a change between the two years, an allocation of the change was calculated and the resulting difference was then applied to both the Low Pressure and Regulated Non-Low Pressure studies, on a pro-rata basis. These changes are reflected in the quantities shown in Exhibit 11, Schedule BEE-2, Pages 7 – 8 and again on Pages 18 – 19.

Q. Were the results of this modified study consistent with the results seen in the 2014 rate case?

A. Yes. As shown in the table below, the allocation factors developed in the 2014 rate case mains study (Docket No. R-2014-2406274, Exhibit 111, Schedule BEE-3, Page 19, Line 22, and Page 33, Line 18) are very similar to those developed in the Company's current case using the modified results of the 2014 mains study.

Year/Study	RSS/RDS	SGSS/SCD/SGDS	LGS	SDS/LGSS	LDS/LGSS	Total
2014 C/D	75.190%	16.663%	0.481%	3.354%	4.312%	100.000%
2015 C/D	75.694%	16.318%	0.000%	4.113%	3.875%	100.000%
2014 P&A	54.990%	22.349%	1.126%	6.993%	14.542%	100.000%
2015 P&A	56.714%	22.120%	0.000%	7.792%	13.374%	100.000%

Q. How has Columbia identified and separated Account 376 – Mains in its current rate case?

A. Columbia is relying on the results of its mains study developed in the 2014 rate case. In that case, Columbia was able to identify and separate, based on operating pressures, its transmission, low pressure, and regulated non-low pressure mains. The physical system data was then analyzed alongside the company's plant accounting system records and its customer billing system ("DIS") records, resulting in a refined and more precise study. Those specific categories of mains were identified and gathered in response to suggestions received in its 2012 rate case. A fourth category, remaining regulated pressure mains, was arrived at by subtracting, from the Company totals (excluding direct

assignment MLS/MLDS), the quantities separately identified as 'transmission', 'low pressure', or 'regulated non-low pressure.' The remaining difference was, by default, 'remaining regulated pressure mains.' This fourth category represents mains that may serve any or all pressure-types of customers, but cannot be identified as serving any one specific type.

Q. Did Columbia change its allocation method for Account 376 – Mains in its current case?

A. No. As in its 2014 case, Columbia's allocation method in its current case follows the same approach. That is, a Peak & Average, Customer/Demand, and Average Study was prepared, incorporating the same allocation factor drivers (i.e. design day volumes, customer counts, throughput) as were used in its prior case. Again, because Columbia is using the mains allocation model from its 2014 case, which contains the more precise data that was provided by the company's systems and engineers, for the transmission, low pressure, and regulated non-low pressure categories, the allocation of costs continues to be assigned to the specific types of customers who utilize those mains. The specific allocation methods used for each of these categories are later explained.

Q. What allocation approach is being applied to 'transmission' mains?

A. Transmission mains are generally not designed to serve individual or small groups of customers, and are typically viewed as being designed to meet the peak demand of an entire geographical area. For this reason, transmission mains are being allocated using the Company's total design day volumes (excluding

MLS/MLDS), in both the Customer-Demand (Exhibit 111, Schedule No. 1) and the Peak & Average (Exhibit 111, Schedule No. 2) studies.

Q. What allocation approach is being applied to 'low pressure' mains?

A. In the Customer-Demand Study, low pressure mains were split into customer and demand components, based on the average cost per foot of a two-inch main. The customer component was calculated by dividing the hypothetical cost of the Company's two-inch low pressure system into the total cost of the Company's low pressure system. This customer component of the low pressure mains was then allocated to rate classes based on the total number of customers (by rate class) served from Columbia's low pressure mains (excluding MLS/MLDS). The demand component was arrived at by calculating the cost of mains, other than the hypothetical cost of the Company's two-inch low pressure systems, and dividing that total into the total cost of the low pressure systems. The demand portion was allocated to rate classes based on the design day volumes for customers served from Columbia's low pressure mains.

In the Peak & Average Study, low pressure mains were allocated, using a 50-50 split, using historical test-year throughput volumes (applicable only to the low pressure customers), and design day volumes applicable only to the low pressure customers (excluding MLS/MLDS).

Q. What are "regulated non-low pressure" mains?

A. Regulated non-low pressure mains are IP, MP and HP systems that do not serve low pressure systems. Customers served from regulated non-low pressure mains

do not receive any gas directly or indirectly from a low pressure system. Conversely, customers served from low pressure system mains do not receive any gas directly or indirectly from a regulated non-low pressure system.

Q. What allocation approach is being applied to the regulated non-low pressure mains?

A. In the Customer-Demand Study and as with the low pressure mains, the regulated non-low pressure mains were split into customer and demand components then allocated to the rate classes, using the same methodology. That is, only the customer counts and design day volumes for the Columbia's regulated non-low pressure customers were used in the allocation process.

Similarly, in the Peak & Average Study, the regulated non-low pressure mains were allocated, using a 50-50 split, using average throughput volumes (based on historical test-year throughput volumes) and design day volumes (both applicable only to the regulated non-low pressure customers and excluding MLS/MLDS).

Q. What are "remaining regulated pressure" mains?

A. Remaining regulated mains are IP, MP and HP systems that serve two purposes: 1) to deliver gas to customers that require IP, MP or HP pressure; and 2) to also deliver gas into downstream low pressure systems and regulated non-low pressure systems. Because these upstream distribution mains are required to serve customers directly tied to both downstream low pressure and regulated non-low pressure systems, Columbia allocates the costs of remaining regulated

pressure mains to all customers (except MLS/MLDS customers, which are directly assigned).

Q. What allocation approach is being applied to the remaining regulated pressure mains?

A. For the Customer-Demand Study, as with the low pressure and the regulated non-low pressure mains, the remaining regulated pressure mains were split into customer and demand components, using the same methodology as previously discussed. However, for these mains, total company (excluding MLS/MLDS) customer counts and design day volumes were used to allocate the mains cost to the rate classes.

For the Peak & Average Study, the same 50-50 split was used to allocate the total mains cost between historical test year throughput and design day volumes. However, for this allocation, total company volumes (throughput and design day) were used. Again, for this allocation, the MLS/MLDS class volumes were excluded from the allocation factor because this class is directly assigned.

Q. How was the demand component for each class determined?

A. The demand component by class was provided by NCSC's Commercial Operations department and represents expected requirements under design day conditions. I note that the calculations reflect design day total requirement, and thus assumes suppliers will make deliveries that are necessary to meet customer requirements.

Q. Why was the MLS/MLDS customer groups excluded from the above described allocations of mains?

A. Customers served under rate schedules MLS/MLDS were excluded from the allocations of mains under all studies because these customers are served directly from a Columbia Gas Transmission, LLC ("Columbia Transmission") interstate pipeline or are in close proximity to a Columbia Transmission interstate pipeline. Accordingly, Columbia has little or no main investment associated with providing service to these customers. An inventory of the mains investment in serving these customers was made by studying the Company's plant records and maps on a customer by customer basis. The mains investment cost then was directly assigned to MLS/MLDS. Therefore, it is appropriate to exclude them from the allocation of mains and mains related cost.

Q. Since a significant portion of the Company's investment and expense is related to mains and services, does the allocation of those items dominate the outcome of the studies?

A. Yes, it does. Mains and services account for approximately 88% of the Company's gross plant investment and approximately 18% of operating and maintenance expenses, excluding gas costs. The allocation of these items significantly influences the outcome of the studies. In addition, many other elements of operation and maintenance expenses are allocated on plant-related factors.

Q. How are purchased gas costs allocated in the studies?

A. Gas costs are directly assigned to each class at the pro forma levels determined by Company witness Lai (Columbia Statement No. 3) in her Exhibit No. 103, Schedule No.1, Pages 13 through 18.

Q. Were there any other major operations and maintenance expense items that you directly assigned?

A. Yes. As shown on Page 8, Lines 7 and 13 of all three studies, I assigned recovery of costs from the Company's Universal Services Program to the residential class. Under both current and proposed rates, these costs are recoverable from the residential class whether sales or delivery service. Line 7 relates to the uncollectible component and Line 13 relates to the customer compliance and other service costs associated with residential customers. This cost category includes the costs associated with customer service activity for residential customers, including the costs associated with the Company's LIURP and Emergency Service programs.

Q. How did you handle Uncollectibles related to unbundling?

A. The total cost was matched to the amount in revenue, and the portion related to small customers was allocated based on DIS revenue and the large customer portion on Gas Measurement Billing/Gas Transportation System revenue. A more detailed description of the allocation is included in Exhibit BEE-2, attached to my testimony.

Q Please describe how you allocated plant Account 380 - Services and the related O&M accounts.

A. First, I identified the services related to MLS/MLDS and directly assigned them. The remaining investment in Account 380 - Services and the related O&M accounts was based on an actual assignment of services installed on customers' premises.

Individual customer services were identified by size from the company's DIS and accumulated by customer class and rate schedule. Based on the historic test year per book data, services were grouped between under three inches and three inches and over. Average unit prices were developed from the data and applied to the number of services under each rate schedule based on size. The resulting values, by rate schedule, were converted to percentages and used to allocate service investment and related expenses.

Q. Please describe how you allocated plant Account 381 – Meters and Account 382 – Meter Installations in the studies.

A. I have assigned meters to the various classes of customers based on an actual inventory of meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size increases. Individual installed meters as identified on DIS were summarized by the four pressure groups. The capitalized property investment as identified on the company's books and records for the four pressure groups was divided by the number of installed meters as reflected on the company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each customer class. The percentages were developed for Account 381 and used for assigning Account 381 Meters as well as the investment in Account 382 Meter Installations.

Q. Please describe how you allocated plant accounts 383 – House Regulators and 384 – House Regulator Installations.

A. Both of these accounts contain costs that are directly associated with the cost of house regulators. These regulators are installed where the distribution lines are transporting gas at intermediate, medium, or high pressure. Recognizing this fact and understanding, therefore, that customers being served by low pressure lines do not require house regulators, I developed an allocation factor that excludes customers served from low pressure lines from the total. The allocation factor uses total number of customers, grouped by rate class, as assigned in DIS. The resulting allocation percentages are then applied to the total capitalized property investment, as identified on the Company's books and records to determine the cost of house regulators for each rate class.

Q. Please describe how you allocated plant Account 385 – M & R Equipment in the studies.

A. Using data retrieved from DIS, I obtained, for each active customer who had an M & R Station assigned to them, each station's rate schedule and identification number. I then cross-referenced these station identification numbers to the Company's plant accounting records to identify the cost of each station. I then grouped these costs into the corresponding rate classes (excluding MLS/MLDS) and used the resulting totals as the basis for allocating all M & R plant.

Q. Do you provide a more complete description of how these factors were developed and the related calculations?

A. Yes. In Exhibits BEE-1 and 2 attached to this testimony, entitled "Development of Allocation Factors" and "Factors 5, 20 and 22," respectively, I have provided a description and, where needed, a calculation for these and all other factors used for the studies. In addition, in Exhibit BEE - 3, I have provided the rationale for factor selection, by account, as it pertains to the various categories of rate base and expense.

Q. Did you prepare a study in support of the Company's minimum or system charges?

A. I prepared two studies in support of the Company's minimum or system charges. They are contained in Exhibit No. 111, Schedule 1, pages 14 through 18.

Q. Please describe the two studies.

A. The study included in Exhibit 111, Schedule No. 1, pages 14 through 16 contains the company's traditional system charge study based on the customer-demand ACOS study and includes the customer portion of mains costs. Columbia has used this method in support of its system charges in its previous general rate case filings. The study shows an overall customer charge component of almost $39.92 (see Schedule 1, Page 14, Column D, Line 40).

The study presented on pages 17 and 18 of Schedule No. 1 is similar, but excludes the customer component of mains and other operations. The study shows an overall customer charge component of almost $18.86 (see Page 17, Column D, Line 37).

Q. Why did you present this study?

A. To my understanding, other parties disagree with the inclusion of any mains costs as a customer component and, therefore, I have included this calculation. The Company does not agree with this approach, and continues to support its traditional customer cost study.

Q. Did you prepare a study supporting the intra-class adjustment of storage costs between the SGDS and the SGSS/SCD classes?

A. Yes. At the request of Witness Lai, I prepared a study, included as Exhibit BEE-4, supporting the intra-class adjustment of approximately $600,000 from the SGDS class to the SGSS and SCD classes.

Q. Please describe this study.

A. The study calculates the storage carrying costs, by rate class, by applying the proposed pre-tax rate of return (Line 6) to the allocated storage balances (Line 3), and utilizing Allocation Factor No. 25. The resulting storage carrying costs for the SGS/SGDS class (Line 7) of $2,341,957 includes costs of $597,433 that would, without an adjustment, be assigned to the SGDS class (Line 15). These costs are assigned to the SGSS and SCD classes ratably, using a factor derived from their projected throughput (Lines 13 & 14 under the heading "Ratio"). No other intra-class adjustments are being supported or shown on this exhibit.

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Direct Assignment

"Direct Assignment" refers to a specific identification and isolation of plant and/or expenses based on Columbia's accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term "direct" immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day

The quantities contained in Factor No. 1 represent the total demand projected to occur at Columbia's design peak day.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2016 are the basis for Factor No. 2.

Factor No. 3- Throughput Excluding MLDS

Factor No. 3 represents the throughput quantities excluding MLDS quantities for the twelve months ending December 31, 2016.

Factor No. 4- Gas Purchase Expense

Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2016 using the applicable Gas Cost Recovery ("GCR") rates.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

.Factor No. 5 - Composite of Factors No. 1 and Throughput

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2014 to produce a composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. Please see Exhibit BEE-3, Development of Allocation Factors Nos. 5, 20 & 22 for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending December 31, 2016 were averaged and used to develop Factor No. 6.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2014 to small usage customers through the Company's Distributive Information System ("DIS").

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2016 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems.

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2014.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 10 - Forfeited Discounts

Factor No. 10 is based on the amount of forfeited discounts billed to customers during the twelve months ended November 30, 2014.

Factor No. 11 - Distribution Plant Excluding Other

Factor No. 11 ratios are based on the spread of distribution plant dollars, excluding gas plant accounts 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 11.

Factor No. 12 - Gross Plant

Factor No. 12 ratios are based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 14 reflects the relationship based on the spread of dollars in accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 14.

Factor No. 15 – Direct Assignment - Services

Factor No. 15 – reflects Services – Account 380 assigned by rate schedule based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size kind from the Company's DIS and accumulated by customer class and rate schedule. Based on the historic test year per book data, services were grouped between under three inches and three inches and over. Average unit prices were developed from the data and applied to the number of services under each rate schedule based on size. The resulting values, by rate schedule were converted to percentages and used to allocate service investment and related expenses.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size changes. Individually installed meters as identified on Columbia's DIS were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the Company's books and records to develop a cost per meter for each group of meters. The

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

costs per meter were multiplied by the identified installed meters on DIS to determine the investment for each customer class. The percentages were developed for account 381 Meter and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations, 383 House Regulators and 384 House Regulator Installations since these costs are incurred in direct relation with meters.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified on Columbia's plant records by rate schedule. The investments, so segregated, are aggregated and reduced to percentages to produce Factor No. 17.

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

Factor No. 19 – O&M Excl Gas Pur, Uncollectibles, & A&G

Factor No. 19 is based on total Operating and Maintenance Expenses (Page 8, Line 34) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 4, 5, 6 & 7), USP Rider (Page 8, Line 13) and A&G Expenses (Page 8, Line 33).

Factor No. 20 Minimum System Mains

Factor No. 20 is used in the Customer-Demand Study. Please see Exhibit BEE-3, Development of Allocation Factors Nos. 5, 20 & 22 for a description and development of Factor No. 20.

Factor No. 21 – Large Customer Relations

Factor No. 21 is based on the accounts supported by the Large Customer Relations group.

Factor No. 22 –Average Factor Nos. 5 & 20

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study.

Factor No. 23 – Unbundled Uncollectibles

Factor No. 23 is based on the amounts to be billed to customers related to the unbundled uncollectibles accounts for the twelve months ending December 31, 2016.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various FERC Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24.

Factor No. 25 – Sales and CHOICE Transportation

Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending December 31, 2016.

Factor No. 26 – House Regulators

Factor No. 26 is based on the bill counts for all customers that are not served by low pressure lines. These counts are segregated by customer class and converted to percentages to create Factor No. 26.

Factor No. 27 – Meters and House Regulators

Factor No. 27 reflects the relationship based on the spread of dollars in accounts 381 Meters, 381.10 Automatic Meter Reading, 382 Meter Installations, 383 House Regulators, and 384 House Regulator Installations (Page 3, Lines 34 through 38) among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 27.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

Factor No. 5 – Composite of Allocator 1 & Historical Throughput

Factor No. 5 combines the design day quantities included in Factor No. 1 and the throughput quantities, for the historic test year ended November 30, 2014, to produce a composite factor. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. This factor reflects an equal weight of design day demand and annual demand under each rate class. The development of the factor is presented on pages 7 - 17 of Exhibit BEE-3.

The total historical cost of the mains, as of November 30, 2014, was obtained from the company's plant accounting system. The quantity of mains was obtained from the company's Geographic Information System ("GIS"), a digital mapping system of the company's distribution system. Additionally, directly assigned mains, for the MLS/MLDS classes, were identified and deducted from the company totals. This data was used to calculate the average cost per foot of each unique combination of kind and size of pipe. From this point, the mains were further grouped into one of the following four allocation categories: 'transmission', 'low pressure', 'regulated non-low pressure' and 'remaining regulated pressure', as explained in Statement No. 7, Pages 6 - 8. The allocation of each of these categories is further explained in Statement No. 7, Pages 8 - 11

From the company's books and records as of the end of the historic test year, the value of all pipe, not directly assigned, is shown on Page 8 Line 22, and again on Page 15, Lines 4 & 9.

The determination of the total cost of $12,083,335 for the transmission pipe was

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on page 9. The allocation of transmission pipe was calculated by applying Allocator No. 1 (total company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Page 18, Line 5.

The determination of the total cost of $217,938,408 for the low pressure only pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Pages 10 & 11. The allocation of low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (low pressure only) by rate class and design day volumes (low pressure only) by rate class to the total cost, as shown on Page 16, Line 15.

The determination of the total cost of $379,849,758 for the regulated non-low pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Page 12 The allocation of regulated non-low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (regulated non-low pressure only) by rate class and design day volumes (regulated non-low pressure only) by rate class to the total cost, as shown on Page 17, Line 10.

The determination of the total cost of $160,511,272 for the remaining regulated pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Pages 13 & 14. The allocation of remaining regulated pressure pipe was calculated by applying, on a 50-50

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

basis, historical throughput (total company excluding MLS/MLDS) by rate class and Allocator No. 1 (total company design day volumes) to the total cost, as shown on Page 17, Line 20.

Each of these four categories of allocated costs were aggregated (Page 17, Line 21), to arrive at a total cost for each rate class. These aggregated amounts were then converted to percentages, as shown on Page 17, Line 22, which formed Allocation Factor No. 5.

Factor No. 20 – 2" Mains Minimum System

Factor No. 20 is a composite using customers and design day quantities to allocate mains. The development of the factor is presented on Pages 18 - 29 of Exhibit BEE-3.

As with Factor No. 5, the total historical cost of the mains, the quantity of mains, and the directly assigned mains were all obtained from the company's systems. Likewise, this data was used to calculate the average cost per foot of each unique combination of kind and size of pipe. Again, the mains were further grouped into one of the following four allocation categories: 'transmission', 'low pressure', 'regulated non-low pressure' and 'remaining regulated pressure', as explained in Statement No. 7, Pages 6 - 8. The allocation of each of these categories is further explained in Statement No. 7, Pages 8 – 11.

The determination of the total cost of $12,083,335 for the transmission pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

respective average cost per unit, as shown on Page 20. The allocation of transmission pipe was calculated by applying Allocator No. 1 (total company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Page 26, Line 14.

For the remaining categories of pipe, a minimum 2" system approach is used. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor.

The already determined total cost of $217,938,408 for the low pressure only pipe was allocated by applying the customer component percentage of 46.358% (Page 27, Line 6) to the average number of low pressure customers, and the demand component percentage 53.642% (Page 27, Line 7) to design day volumes (low pressure only). Finally, these two results (Page 27, Lines 11 & 14) are added together to form the minimum system percentages as shown on Page 27, Line 15.

As with the method for determining the low pressure minimum system

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

percentage, the total cost of $379,849,758 for the regulated non-low pressure only pipe was allocated by applying the customer component percentage of 56.758% (Page 28, Line 6) to the average number of regulated non-low pressure customers, and the demand component percentage 43.242% (Page 28, Line 7) to design day volumes (regulated non-low pressure only). Finally, these two results (Page 28, Lines 11 & 14) are added together to form the minimum system percentages as shown on Page 28, Line 15.

Again, following the same method for determining the low pressure and regulated non-low pressure minimum system percentages, the total cost of $160,511,272 for the remaining regulated pressure pipe was allocated by applying the customer component percentage of 37.543% (Page 29, Line 6) to the average number of company customers (excluding MLS/MLDS), and the demand component percentage 62.457% (Page 29, Line 7) to total company design day volumes (excluding MLS/MLDS). Finally, these two results (Page 29, Lines 11 & 14) are added together to form the minimum system percentages as shown on Page 29, Line 15.

Each of these four categories of allocated costs were aggregated (Page 29, Line 17), to arrive at a total cost for each rate class. These aggregated amounts were then converted to percentages, as shown on Page 29, Line 18, which formed Allocation Factor No. 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

Factor No. 22 – Average of 5 & 20

Factor No. 22 is an average of Factor No. 5 and Factor No. 20 and is applied to mains and mains related costs to produce the Average study.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: B.ELLIOTT

1 **Total Company - Average Unit Cost of Mains**

2			Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	CAST IRON	3"	12,787	9,295	0	-	12,787	9,295	0.7269
5	CAST IRON	4"	119,726	275,642	0	-	119,726	275,642	2.3023
6	CAST IRON	6"	49,160	107,717	0	-	49,160	107,717	2.1911
7	CAST IRON	8"	13,471	66,288	0	-	13,471	66,288	4.9208
8	CAST IRON	10"	2,202	8,506	0	-	2,202	8,506	3.8628
9	CAST IRON	12"	867	58,051	0	-	867	58,051	66.9560
10	PLASTIC	1"	37,189	139,475	0	-	37,189	139,475	3.7504
11	PLASTIC	1-1/8"	2,303	5,709	0	-	2,303	5,709	2.4790
12	PLASTIC	1-1/4"	393,889	2,182,582	0	-	393,889	2,182,582	5.5411
13	PLASTIC	2"	9,549,727	121,789,892	0	-	9,549,727	121,789,892	12.7532
14	PLASTIC	3"	2,288,845	27,847,440	0	-	2,288,845	27,847,440	12.1666
15	PLASTIC	4"	5,758,209	215,363,249	0	-	5,758,209	215,363,249	37.4011
16	PLASTIC	6"	2,205,373	132,942,884	645	20,688	2,204,728	132,922,196	60.2896
17	PLASTIC	8"	1,037,084	92,547,537	0	-	1,037,084	92,547,537	89.2382
18	PLASTIC	10"	362	74	0	-	362	74	0 2035
19	STEEL	1"	59,460	107,719	0	-	59,460	107,719	1.8116
20	STEEL	1/2"	3	233	0	-	3	233	77.7433
21	STEEL	10"	756,442	20,794,978	0	-	756,442	20,794,978	27.4905
22	STEEL	1-1/2"	15,885	12,649	0	-	15,885	12,649	0.7963
23	STEEL	1-1/4"	304,554	771,004	0	-	304,554	771,004	2.5316
24	STEEL	12"	411,608	24,580,511	0	-	411,608	24,580,511	59.7183
25	STEEL	14"	450	5,167	0	-	450	5,167	11 4820
26	STEEL	16"	321,082	17,565,799	0	-	321,082	17,565,799	54.7082
27	STEEL	2"	4,137,035	9,170,709	840	4,331	4,136,195	9,166,378	2.2161
28	STEEL	20"	34,204	6,961,170	0	-	34,204	6,961,170	203.5192
29	STEEL	2-1/2"	5,025	3,292	0	-	5,025	3,292	0.6552
30	STEEL	3"	1,052,132	3,096,324	0	-	1,052,132	3,096,324	2.9429
31	STEEL	3/4"	8,097	13,153	0	-	8,097	13,153	1.6244
32	STEEL	3-1/2"	8,138	27,469	0	-	8,138	27,469	3.3755
33	STEEL	3-1/4"	653	3,764	0	-	653	3,764	5.7646
34	STEEL	4"	5,571,412	24,464,967	729	7,302	5,570,683	24,457,665	4.3904
35	STEEL	4-1/2"	4,004	24,094	0	-	4,004	24,094	6.0175
36	STEEL	4-7/8"	17,345	19,108	93	41	17,252	19,067	1.1052
37	STEEL	5"	53,378	52,520	0	-	53,378	52,520	0.9839
38	STEEL	5-1/2"	295	343	0	-	295	343	1.1641
39	STEEL	5-1/4"	621	344	0	-	621	344	0.5541
40	STEEL	5-3/16"	19,665	38,663	0	-	19,665	38,663	1.9661
41	STEEL	5-5/8"	21,122	22,430	0	-	21,122	22,430	1.0619

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

1 **Total Company - Average Unit Cost of Mains (Cont)**

2			Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	STEEL	6"	3,412,553	32,020,924	11,248	85,819	3,401,305	31,935,105	9.3891
5	STEEL	6-1/4"	21,608	6,032	0	-	21,608	6,032	0.2791
6	STEEL	6-5/8"	117,908	744,239	0	-	117,908	744,239	6.3120
7	STEEL	7-5/8"	5,904	15,405	0	-	5,904	15,405	2.6092
8	STEEL	8"	1,671,243	36,232,043	2,767	18,300	1,668,476	36,213,743	21.7047
9	STEEL	8-1/4"	962	3,657	0	-	962	3,657	3.8017
10	STEEL	8-5/8"	8,232	361,804	0	-	8,232	361,804	43.9509
11	STEEL	9-5/8"	1,269	7,380	0	-	1,269	7,380	5.8153
12	WROUGHT IRON	1"	2,719	15,182	0	-	2,719	15,182	5.5836
13	WROUGHT IRON	10"	65,379	683	0	-	65,379	683	0.0104
14	WROUGHT IRON	12"	18,034	5,721	0	-	18,034	5,721	0.3173
15	WROUGHT IRON	2"	43,236	10,346	0	-	43,236	10,346	0.2393
16	WROUGHT IRON	3"	59,545	8,009	0	-	59,545	8,009	0.1345
17	WROUGHT IRON	4"	77,574	4,358	0	-	77,574	4,358	0.0562
18	WROUGHT IRON	6"	81,283	254	0	-	81,283	254	0.0031
19	WROUGHT IRON	6-5/8"	1,622	151	0	-	1,622	151	0.0929
20	WROUGHT IRON	7-5/8"	6,563	2	0	-	6,563	2	0.0004
21	WROUGHT IRON	8"	157,409	2,308	0	-	157,409	2,308	0.0147
22	Total		40,026,847	770,519,253	16,322	136,480	40,010,525	770,382,773	19.2545

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: B.ELLIOTT

1 **Total Company - Transmission Class Mains**

2				Average	
3	Kind	Size	Quantity	Unit Cost	Amount
4	STEEL	10"	64,241	27.4905	1,766,017
5	STEEL	12"	109,227	59.7183	6,522,851
6	STEEL	16"	13,570	54.7082	742,390
7	STEEL	2"	194	2.2161	430
8	STEEL	4"	5,731	4.3904	25,161
9	STEEL	6"	9,991	9.3891	93,807
10	STEEL	8"	134,888	21.7047	2,927,704
11	WROUGHT IRON	12"	15,680	0.3173	4,975
12	Total		353,522		12,083,335

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: B.ELLIOTT

1 **Total Company - Distribution Low Pressure Mains**

2				Average	
3	Kind	Size	Quantity	Unit Cost	Amount
4	CAST IRON	3"	12,787	0.7269	9,295
5	CAST IRON	4"	119,470	2.3023	275,056
6	CAST IRON	6"	49,160	2.1911	107,714
7	CAST IRON	8"	13,471	4.9208	66,288
8	CAST IRON	10"	2,202	3.8628	8,506
9	CAST IRON	12"	867	66.9560	58,051
10	PLASTIC	1"	7,811	3.7504	29,294
11	PLASTIC	1-1/8"	1,140	2.4790	2,826
12	PLASTIC	1-1/4"	69,322	5.5411	384,120
13	PLASTIC	2"	1,269,068	12.7532	16,184,678
14	PLASTIC	3"	807,811	12.1666	9,828,313
15	PLASTIC	4"	1,980,358	37.4011	74,067,568
16	PLASTIC	6"	757,916	60.2896	45,694,452
17	PLASTIC	8"	274,954	89.2382	24,536,400
18	PLASTIC	10"	241	0.2035	49
19	STEEL	1"	5,505	1.8116	9,973
20	STEEL	10"	159,251	27.4905	4,377,889.6
21	STEEL	1-1/2"	5,355	0.7963	4,264
22	STEEL	1-1/4"	15,043	2.5316	38,083
23	STEEL	12"	42,158	59.7183	2,517,604
24	STEEL	14"	450	11.4820	5,167
25	STEEL	16"	22,597	54.7082	1,236,241
26	STEEL	2"	911,471	2.2161	2,019,911
27	STEEL	20"	1,668	203.5192	339,470
28	STEEL	2-1/2"	2,894	0.6552	1,896
29	STEEL	3"	571,702	2.9429	1,682,462
30	STEEL	3/4"	164	1.6244	266
31	STEEL	3-1/2"	7,532	3.3755	25,424
32	STEEL	4"	2,987,982	4.3904	13,118,436
33	STEEL	4-1/2"	3,266	6.0175	19,653
34	STEEL	4-7/8"	12,712	1.1052	14,049
35	STEEL	5"	26,356	0.9839	25,932
36	STEEL	5-1/2"	295	1.1641	343
37	STEEL	5-5/8"	16,970	1.0619	18,020
38	STEEL	6"	1,552,591	9.3891	14,577,432
39	STEEL	6-5/8"	83,280	6.3120	525,663
40	STEEL	8"	282,170	21.7047	6,124,415
41	WROUGHT IRON	10"	2,076	0.0104	22

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

Total Company - Distribution Low Pressure Mains (Cont)

	Kind	Size	Quantity	Average Unit Cost	Amount
4	WROUGHT IRON	12"	2,354	0.3173	747
5	WROUGHT IRON	2"	1,684	0.2393	403
6	WROUGHT IRON	3"	10,159	0.1345	1,366
7	WROUGHT IRON	4"	10,399	0.0562	584
8	WROUGHT IRON	6"	5,308	0.0031	16
9	WROUGHT IRON	8"	4,240	0.0147	62
10	Total		12,114,210		217,938,408.22

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

1 **Total Company - Distribution Regulated Pressure Only Mains**

2				Average	
3	Kind	Size	Quantity	Unit Cost	Amount
4	CAST IRON	4"	256	2.30	589.41
5	PLASTIC	1"	27,818	3.75	104,330 02
6	PLASTIC	1-1/8"	1,120	2.48	2,775.50
7	PLASTIC	1-1/4"	316,105	5.54	1,751,571.77
8	PLASTIC	2"	8,013,766	12.75	102,201,158.64
9	PLASTIC	3"	1,406,003	12.17	17,106,270.38
10	PLASTIC	4"	3,307,413	37.40	123,700,885.10
11	PLASTIC	6"	1,020,120	60.29	61,502,605.65
12	PLASTIC	8"	332,669	89.24	29,686,763.12
13	STEEL	1"	53,955	1.81	97,745.20
14	STEEL	1/2"	3	77.74	219 35
15	STEEL	10"	39,576	27.49	1,087,958.80
16	STEEL	1-1/2"	10,530	0.80	8,384.82
17	STEEL	1-1/4"	289,511	2.53	732,927.01
18	STEEL	12"	43,893	59.72	2,621,194.44
19	STEEL	16"	45,747	54.71	2,502,740.95
20	STEEL	2"	3,224,530	2.22	7,145,880.67
21	STEEL	20"	89	203 52	18,113.21
22	STEEL	3"	471,394	2.94	1,387,264.52
23	STEEL	4"	2,109,931	4.39	9,263,439.92
24	STEEL	5"	27,022	0.98	26,586 95
25	STEEL	6"	938,890	9.39	8,815,334.92
26	STEEL	8"	464,603	21.70	10,084,060.05
27	WROUGHT IRON	2"	3,474	0.24	831.33
28	WROUGHT IRON	6"	771	0.00	2.39
29	WROUGHT IRON	8"	8,438	0.01	124.04
30	Total		22,157,625		379,849,758.16

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: B.ELLIOTT

1 **Total Company - Remaining Regulated Pressure Mains**

2

3	Kind	Size	Quantity	Amount
4	CAST IRON	3"	0	0.36
5	CAST IRON	4"	(0)	(3.14)
6	CAST IRON	6"	0	2.29
7	CAST IRON	8"	0	(0.20)
8	CAST IRON	10"	0	0.07
9	CAST IRON	12"	0	0.03
10	PLASTIC	1"	1,560	5,850.95
11	PLASTIC	1-1/8"	43	107.69
12	PLASTIC	1-1/4"	8,462	46,889.86
13	PLASTIC	2"	266,893	3,404,055.73
14	PLASTIC	3"	75,032	912,856.18
15	PLASTIC	4"	470,438	17,594,796.54
16	PLASTIC	6"	426,692	25,725,137.86
17	PLASTIC	8"	429,461	38,324,373.73
18	PLASTIC	10"	121	24.62
19	STEEL	1"	(0)	0.44
20	STEEL	1/2"	0	13 88
21	STEEL	10"	493,375	13,563,112 60
22	STEEL	1-1/2"	0	0.40
23	STEEL	1-1/4"	(0)	(5.48)
24	STEEL	12"	216,330	12,918,861.23
25	STEEL	14"	0	(0.02)
26	STEEL	16"	239,168	13,084,426.74
27	STEEL	2"	(0)	156.91
28	STEEL	20"	32,447	6,603,587.07
29	STEEL	2-1/2"	2,131	1,396.31
30	STEEL	3"	9,036	26,597.51
31	STEEL	3/4"	7,933	12,886.60
32	STEEL	3-1/2"	606	2,045.15
33	STEEL	3-1/4"	653	3,764.26
34	STEEL	4"	467,039	2 050,627.90
35	STEEL	4-1/2"	738	4,440.88
36	STEEL	4-7/8"	4,540	5,017.86
37	STEEL	5"	0	1.81
38	STEEL	5-1/2"	0	0 01
39	STEEL	5-1/4"	621	344 07
40	STEEL	5-3/16"	19,665	38,663 18
41	STEEL	5-5/8"	4,152	4,409.98

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

1 **Total Company - Remaining Regulated Pressure Mains (Cont)**

2

3	Kind	Size	Quantity	Amount
4	STEEL	6"	899,832	8,448,531.78
5	STEEL	6-1/4"	21,608	6,031.68
6	STEEL	6-5/8"	34,628	218,575.42
7	STEEL	7-5/8"	5,904	15,404.79
8	STEEL	8"	786,815	17,077,564.10
9	STEEL	8-1/4"	962	3,657.28
10	STEEL	8-5/8"	8,232	361,803.89
11	STEEL	9-5/8"	1,269	7,379.67
12	WROUGHT IRON	1"	2,719	15,181.68
13	WROUGHT IRON	10"	63,303	661.60
14	WROUGHT IRON	12"	0	(0.87)
15	WROUGHT IRON	2"	38,078	9,111 95
16	WROUGHT IRON	3"	49,386	6,642.78
17	WROUGHT IRON	4"	67,175	3,773.85
18	WROUGHT IRON	6"	75,204	235.25
19	WROUGHT IRON	6-5/8"	1,622	150.66
20	WROUGHT IRON	7-5/8"	6,563	2.36
21	WROUGHT IRON	8"	144,731	2,122.07
22	Total		5,385,168	160,511,272

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Total Mains Plant in Service**		984,881,701.43						
2	**Direct Assigned Plant**		136,480.33						
3	**Other - Non Pipe**		214,362,448.06						
4	**Allocable Pipe**		770,382,773.04						
5	**Transmission Pipe**		12,083,334.86						
6	**Low Pressure Pipe**		217,938,408.22						
7	**Regulated Pressure Pipe Only**		379,849,758.16						
8	**Remaining Regulated Pressure Pipe**		160,511,271.80						
9	**Allocated Pipe**		770,382,773.04						
10	**Allocation of Transmission Pipe**								
11	Allocable Transmission Pipe		$12,083,334.86						
12	Design Day Volumes (Total Company Excluding MDS)		791,995	458,700	189,733	0	65,702	77,860	
13	Percent Design Day Volumes		100.000%	57.917%	23.956%	0.000%	8.296%	9.831%	
14	**Allocation of Transmission Pipe**		**$12,083,334.86**	**$6,998,305.05**	**$2,894,683.70**	**$0.00**	**1,002,433.46**	**1,187,912.65**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Allocation of Transmission Pipe**								
2	Allocable Transmission Pipe		$12,083,334.86						
3	Design Day Volumes (Total Company Excluding MDS)		791,995	458,700	189,733	0	65,702	77,860	
4	Percent Design Day Volumes		100.000%	57.917%	23.956%	0.000%	8.296%	9.831%	
5	**Allocation of Transmission Pipe**		**$12,083,334.86**	**$6,998,305.05**	**$2,894,683.70**	**$0.00**	**1,002,433.46**	**1,187,912.65**	
6	**Allocation of Low Pressure Pipe**								
7	Allocable Low Pressure Pipe		$217,938,408.22						
8	Throughput Volumes (excl MDS)		24,410,606.0	18,895,849.9	5,143,483 5	0.0	281,055.6	90,217.0	
9	Percent Throughput		100.000%	77.408%	21.071%	0.000%	1.151%	0.370%	
10	Throughput Component		50.000%	38.704%	10.536%	0.000%	0.576%	0.185%	
11	Design Day Volumes (excl MDS)		285,850	224,300	59,495	0	2,053	2	
12	Percent Design Day Volumes		100.000%	78.468%	20.813%	0.000%	0.718%	0.001%	
13	Demand Component		50.000%	39.234%	10.407%	0.000%	0.359%	0.001%	
14	Peak & Average Factor		100.000%	77.936%	20.943%	0.000%	0.935%	0.186%	
15	**Allocation of Low Pressure Pipe**		**$217,938,408.22**	**$169,852,477.83**	**$45,642,840.83**	**$0.00**	**2,037,724.12**	**405,365.44**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Allocation of Regulated Pressure Only Pipe**								
2	Allocable Regulated Pressure Only Pipe		$379,849,758.16						
3	Throughput Volumes (excl MDS)		27,537,653.4	11,677,892.2	5,492,697.2	0.0	2,714,731.0	7,652,333.0	
4	Percent Throughput		100.000%	42.407%	19.946%	0 000%	9.858%	27.789%	
5	Throughput Component		50.000%	21.204%	9.973%	0 000%	4.929%	13.895%	
6	Design Day Volumes (excl MDS)		277,730	139,100	71,149	0	35,828	31,653	
7	Percent Design Day Volumes		100.000%	50.085%	25.618%	0.000%	12.900%	11.397%	
8	Demand Component		50.000%	25.043%	12.809%	0.000%	6.450%	5.699%	
9	Peak & Average Factor		100.000%	46.245%	22.782%	0.000%	11.379%	19.594%	
10	**Allocation of Regulated Pressure Only Pipe**		**$379,849,758.16**	**$175,661,520.67**	**$86,537,371.80**	**$0.00**	**43,223,103.98**	**74,427,761.61**	
11	**Allocation of Remaining Regulated Pressure Pipe**								
12	Allocable Remaining Regulated Pressure Pipe		$160,511,271.80						
13	Throughput Volumes (Total Company excl MDS)		81,824,556	38,662,408	16,424,024	0	7,243,498	19,494,626	
14	Percent Throughput		100.000%	47.251%	20.072%	0 000%	8.852%	23.825%	
15	Throughput Component		50.000%	23.626%	10.036%	0.000%	4.426%	11.913%	
16	Design Day Volumes (Total Company excl MDS)		791,995	458,700	189,733	0	65,702	77,860	
17	Percent Design Day Volumes		100.000%	57.917%	23.956%	0.000%	8.296%	9.831%	
18	Demand Component		50.000%	28.959%	11.978%	0.000%	4.148%	4.916%	
19	Peak & Average Factor		100.000%	52.583%	22.014%	0.000%	8.574%	16.829%	
20	**Alloc. of Remaining Regulated Pressure Pipe**		**$160,511,271.80**	**$84,401,642.06**	**$35,334,951.37**	**$0.00**	**13,762,236.44**	**27,012,441.93**	
21	**Total Peak & Average Allocation Factor**		**$770,382,773.04**	**$436,913,945.61**	**$170,409,847.80**	**$0.00**	**60,025,498.00**	**103,033,481.63**	
22			**100.000%**	**56.714%**	**22.120%**	**0.000%**	**7.792%**	**13.374%**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

1 **Total Company - Average Unit Cost of Mains**

2			Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	CAST IRON	3"	12,787	9,295	0	-	12,787	9,295	0.7269
5	CAST IRON	4"	119,726	275,642	0	-	119,726	275,642	2.3023
6	CAST IRON	6"	49,160	107,717	0	-	49,160	107,717	2.1911
7	CAST IRON	8"	13,471	66,288	0	-	13,471	66,288	4.9208
8	CAST IRON	10"	2,202	8,506	0	-	2,202	8,506	3.8628
9	CAST IRON	12"	867	58,051	0	-	867	58,051	66.9560
10	PLASTIC	1"	37,189	139,475	0	-	37,189	139,475	3.7504
11	PLASTIC	1-1/8"	2,303	5,709	0	-	2,303	5,709	2.4790
12	PLASTIC	1-1/4"	393,889	2,182,582	0	-	393,889	2,182,582	5.5411
13	PLASTIC	2"	9,549,727	121,789,892	0	-	9,549,727	121,789,892	12.7532
14	PLASTIC	3"	2,288,845	27,847,440	0	-	2,288,845	27,847,440	12.1666
15	PLASTIC	4"	5,758,209	215,363,249	0	-	5,758,209	215,363,249	37.4011
16	PLASTIC	6"	2,205,373	132,942,884	645	20,688	2,204,728	132,922,196	60.2896
17	PLASTIC	8"	1,037,084	92,547,537	0	-	1,037,084	92,547,537	89.2382
18	PLASTIC	10"	362	74	0	-	362	74	0.2035
19	STEEL	1"	59,460	107,719	0	-	59,460	107,719	1.8116
20	STEEL	1/2"	3	233	0	-	3	233	77.7433
21	STEEL	10"	756,442	20,794,978	0	-	756,442	20,794,978	27.4905
22	STEEL	1-1/2"	15,885	12,649	0	-	15,885	12,649	0.7963
23	STEEL	1-1/4"	304,554	771,004	0	-	304,554	771,004	2.5316
24	STEEL	12"	411,608	24,580,511	0	-	411,608	24,580,511	59.7183
25	STEEL	14"	450	5,167	0	-	450	5,167	11.4820
26	STEEL	16"	321,082	17,565,799	0	-	321,082	17,565,799	54.7082
27	STEEL	2"	4,137,035	9,170,709	840	4,331	4,136,195	9,166,378	2.2161
28	STEEL	20"	34,204	6,961,170	0	-	34,204	6,961,170	203.5192
29	STEEL	2-1/2"	5,025	3,292	0	-	5,025	3,292	0.6552
30	STEEL	3"	1,052,132	3,096,324	0	-	1,052,132	3,096,324	2.9429
31	STEEL	3/4"	8,097	13,153	0	-	8,097	13,153	1.6244
32	STEEL	3-1/2"	8,138	27,469	0	-	8,138	27,469	3.3755
33	STEEL	3-1/4"	653	3,764	0	-	653	3,764	5.7646
34	STEEL	4"	5,571,412	24,464,967	729	7,302	5,570,683	24,457,665	4.3904
35	STEEL	4-1/2"	4,004	24,094	0	-	4,004	24,094	6.0175
36	STEEL	4-7/8"	17,345	19,108	93	41	17,252	19,067	1.1052
37	STEEL	5"	53,378	52,520	0	-	53,378	52,520	0.9839
38	STEEL	5-1/2"	295	343	0	-	295	343	1.1641
39	STEEL	5-1/4"	621	344	0	-	621	344	0.5541
40	STEEL	5-3/16"	19,665	38,663	0	-	19,665	38,663	1.9661
41	STEEL	5-5/8"	21,122	22,430	0	-	21,122	22,430	1.0619

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

1 **Total Company - Average Unit Cost of Mains (Cont)**

2			Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	STEEL	6"	3,412,553	32,020,924	11,248	85,819	3,401,305	31,935,105	9.3891
5	STEEL	6-1/4"	21,608	6,032	0	-	21,608	6,032	0.2791
6	STEEL	6-5/8"	117,908	744,239	0	-	117,908	744,239	6.3120
7	STEEL	7-5/8"	5,904	15,405	0	-	5,904	15,405	2.6092
8	STEEL	8"	1,671,243	36,232,043	2,767	18,300	1,668,476	36,213,743	21.7047
9	STEEL	8-1/4"	962	3,657	0	-	962	3,657	3.8017
10	STEEL	8-5/8"	8,232	361,804	0	-	8,232	361,804	43.9509
11	STEEL	9-5/8"	1,269	7,380	0	-	1,269	7,380	5.8153
12	WROUGHT IRON	1"	2,719	15,182	0	-	2,719	15,182	5.5836
13	WROUGHT IRON	10"	65,379	683	0	-	65,379	683	0.0104
14	WROUGHT IRON	12"	18,034	5,721	0	-	18,034	5,721	0.3173
15	WROUGHT IRON	2"	43,236	10,346	0	-	43,236	10,346	0.2393
16	WROUGHT IRON	3"	59,545	8,009	0	-	59,545	8,009	0.1345
17	WROUGHT IRON	4"	77,574	4,358	0	-	77,574	4,358	0.0562
18	WROUGHT IRON	6"	81,283	254	0	-	81,283	254	0.0031
19	WROUGHT IRON	6-5/8"	1,622	151	0	-	1,622	151	0.0929
20	WROUGHT IRON	7-5/8"	6,563	2	0	-	6,563	2	0.0004
21	WROUGHT IRON	8"	157,409	2,308	0	-	157,409	2,308	0.0147
22	Total		40,026,847	770,519,253	16,322	136,480	40,010,525	770,382,773	19.2545

COLUMBIA GAS OF PENNSYLVANIA, INC
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Total Company - Transmission Class Mains

	Kind	Size	Quantity	Average Unit Cost	Amount
4	STEEL	10"	64,241	27.4905	1,766,017
5	STEEL	12"	109,227	59.7183	6,522,851
6	STEEL	16"	13,570	54.7082	742,390
7	STEEL	2"	194	2.2161	430
8	STEEL	4"	5,731	4.3904	25,161
9	STEEL	6"	9,991	9.3891	93,807
10	STEEL	8"	134,888	21 7047	2,927,704
11	WROUGHT IRON	12"	15,680	0.3173	4,975
12	Total		353,522		12,083,335

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Total Company - Distribution Low Pressure Mains

	Kind	Size	Quantity	Average Unit Cost	Amount
4	CAST IRON	3"	12,787	0.7269	9,295
5	CAST IRON	4"	119,470	2.3023	275,056
6	CAST IRON	6"	49,160	2.1911	107,714
7	CAST IRON	8"	13,471	4.9208	66,288
8	CAST IRON	10"	2,202	3.8628	8,506
9	CAST IRON	12"	867	66.9560	58,051
10	PLASTIC	1"	7,811	3.7504	29,294
11	PLASTIC	1-1/8"	1,140	2.4790	2,826
12	PLASTIC	1-1/4"	69,322	5.5411	384,120
13	PLASTIC	2"	1,269,068	12.7532	16,184,678
14	PLASTIC	3"	807,811	12.1666	9,828,313
15	PLASTIC	4"	1,980,358	37.4011	74,067,568
16	PLASTIC	6"	757,916	60 2896	45,694,452
17	PLASTIC	8"	274,954	89.2382	24,536,400
18	PLASTIC	10"	241	0.2035	49
19	STEEL	1"	5,505	1.8116	9,973
20	STEEL	10"	159,251	27.4905	4,377,889.6
21	STEEL	1-1/2"	5,355	0.7963	4,264
22	STEEL	1-1/4"	15,043	2.5316	38,083
23	STEEL	12"	42,158	59.7183	2,517,604
24	STEEL	14"	450	11.4820	5,167
25	STEEL	16"	22,597	54 7082	1,236,241
26	STEEL	2"	911,471	2.2161	2,019,911
27	STEEL	20"	1,668	203.5192	339,470
28	STEEL	2-1/2"	2,894	0.6552	1,896
29	STEEL	3"	571,702	2.9429	1,682,462
30	STEEL	3/4"	164	1.6244	266
31	STEEL	3-1/2"	7,532	3.3755	25,424
32	STEEL	4"	2,987,982	4.3904	13,118,436
33	STEEL	4-1/2"	3,266	6.0175	19,653
34	STEEL	4-7/8"	12,712	1.1052	14,049
35	STEEL	5"	26,356	0 9839	25,932
36	STEEL	5-1/2"	295	1.1641	343
37	STEEL	5-5/8"	16,970	1.0619	18,020
38	STEEL	6"	1,552,591	9.3891	14,577,432
39	STEEL	6-5/8"	83,280	6.3120	525,663
40	STEEL	8"	282,170	21.7047	6,124,415
41	WROUGHT IRON	10"	2,076	0.0104	22

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Total Company - Distribution Low Pressure Mains (Cont)

	Kind	Size	Quantity	Average Unit Cost	Amount
4	WROUGHT IRON	12"	2,354	0.3173	747
5	WROUGHT IRON	2"	1,684	0.2393	403
6	WROUGHT IRON	3"	10,159	0.1345	1,366
7	WROUGHT IRON	4"	10,399	0.0562	584
8	WROUGHT IRON	6"	5,308	0.0031	16
9	WROUGHT IRON	8"	4,240	0.0147	62
10	Total		12,114,210		217,938,408.22

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

1 **Total Company - Distribution Regulated Pressure Only Mains**

2				Average	
3	Kind	Size	Quantity	Unit Cost	Amount
4	CAST IRON	4"	256	2.30	589.41
5	PLASTIC	1"	27,818	3.75	104,330.02
6	PLASTIC	1-1/8"	1,120	2.48	2,775.50
7	PLASTIC	1-1/4"	316,105	5.54	1,751,571.77
8	PLASTIC	2"	8,013,766	12.75	102,201,158.64
9	PLASTIC	3"	1,406,003	12.17	17,106,270.38
10	PLASTIC	4"	3,307,413	37.40	123,700,885.10
11	PLASTIC	6"	1,020,120	60.29	61,502,605.65
12	PLASTIC	8"	332,669	89.24	29,686,763.12
13	STEEL	1"	53,955	1.81	97,745.20
14	STEEL	1/2"	3	77.74	219.35
15	STEEL	10"	39,576	27.49	1,087,958 80
16	STEEL	1-1/2"	10,530	0.80	8,384.82
17	STEEL	1-1/4"	289,511	2.53	732,927.01
18	STEEL	12"	43,893	59.72	2,621,194.44
19	STEEL	16"	45,747	54.71	2,502,740.95
20	STEEL	2"	3,224,530	2.22	7,145,880.67
21	STEEL	20"	89	203.52	18,113.21
22	STEEL	3"	471,394	2.94	1,387,264.52
23	STEEL	4"	2,109,931	4.39	9,263,439.92
24	STEEL	5"	27,022	0.98	26,586.95
25	STEEL	6"	938,890	9.39	8,815,334.92
26	STEEL	8"	464,603	21.70	10,084,060.05
27	WROUGHT IRON	2"	3,474	0.24	831.33
28	WROUGHT IRON	6"	771	0.00	2 39
29	WROUGHT IRON	8"	8,438	0.01	124 04
30	Total		22,157,625		379,849,758.16

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

1 **Total Company - Remaining Regulated Pressure Mains**

2

3	Kind	Size	Quantity	Amount
4	CAST IRON	3"	0	0.36
5	CAST IRON	4"	(0)	(3.14)
6	CAST IRON	6"	0	2.29
7	CAST IRON	8"	0	(0.20)
8	CAST IRON	10"	0	0.07
9	CAST IRON	12"	0	0 03
10	PLASTIC	1"	1,560	5,850.95
11	PLASTIC	1-1/8"	43	107.69
12	PLASTIC	1-1/4"	8,462	46,889.86
13	PLASTIC	2"	266,893	3,404,055.73
14	PLASTIC	3"	75,032	912,856.18
15	PLASTIC	4"	470,438	17,594,796.54
16	PLASTIC	6"	426,692	25,725,137.86
17	PLASTIC	8"	429,461	38,324,373.73
18	PLASTIC	10"	121	24 62
19	STEEL	1"	(0)	0.44
20	STEEL	1/2"	0	13.88
21	STEEL	10"	493,375	13,563,112.60
22	STEEL	1-1/2"	0	0.40
23	STEEL	1-1/4"	(0)	(5.48)
24	STEEL	12"	216,330	12,918,861.23
25	STEEL	14"	0	(0.02)
26	STEEL	16"	239,168	13,084,426.74
27	STEEL	2"	(0)	156.91
28	STEEL	20"	32,447	6,603,587.07
29	STEEL	2-1/2"	2,131	1,396.31
30	STEEL	3"	9,036	26,597.51
31	STEEL	3/4"	7,933	12,886.60
32	STEEL	3-1/2"	606	2,045.15
33	STEEL	3-1/4"	653	3,764.26
34	STEEL	4"	467,039	2,050,627.90
35	STEEL	4-1/2"	738	4,440.88
36	STEEL	4-7/8"	4,540	5,017.86
37	STEEL	5"	0	1.81
38	STEEL	5-1/2"	0	0.01
39	STEEL	5-1/4"	621	344.07
40	STEEL	5-3/16"	19,665	38,663.18
41	STEEL	5-5/8"	4,152	4,409.98

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: B.ELLIOTT

1 **Total Company - Remaining Regulated Pressure Mains (Cont)**

2

3	Kind	Size	Quantity	Amount
4	STEEL	6"	899,832	8,448,531.78
5	STEEL	6-1/4"	21,608	6,031.68
6	STEEL	6-5/8"	34,628	218,575.42
7	STEEL	7-5/8"	5,904	15,404.79
8	STEEL	8"	786,815	17,077,564.10
9	STEEL	8-1/4"	962	3,657.28
10	STEEL	8-5/8"	8,232	361,803.89
11	STEEL	9-5/8"	1,269	7,379.67
12	WROUGHT IRON	1"	2,719	15,181.68
13	WROUGHT IRON	10"	63,303	661.60
14	WROUGHT IRON	12"	0	(0.87)
15	WROUGHT IRON	2"	38,078	9,111.95
16	WROUGHT IRON	3"	49,386	6,642.78
17	WROUGHT IRON	4"	67,175	3,773.85
18	WROUGHT IRON	6"	75,204	235.25
19	WROUGHT IRON	6-5/8"	1,622	150.66
20	WROUGHT IRON	7-5/8"	6,563	2.36
21	WROUGHT IRON	8"	144,731	2,122 07
22	Total		5,385,168	160,511,272

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Total Mains Plant in Service**		984,881,701.43						
2	**Direct Assigned Plant**		136,480.33						
3	**Other - Non Pipe**		214,362,448.06						
4	**Allocable Pipe**		770,382,773.04						
5	**Transmission Pipe**		12,083,334.86						
6	**Low Pressure Pipe**		217,938,408.22						
7	**Regulated Pressure Pipe Only**		379,849,758.16						
8	**Remaining Regulated Pressure Pipe**		160,511,271.80						
9	**Allocated Pipe**		770,382,773.04						
10	**Allocation of Transmission Pipe**								
11	Allocable Transmission Pipe		$12,083,334.86						
12	Design Day Volumes (Total Company Excluding MDS)		791,995	458,700	189,733	0	65,702	77,860	
13	Percent Design Day Volumes		100.000%	57.917%	23.956%	0.000%	8.296%	9.831%	
14	**Allocation of Transmission Pipe**		**$12,083,334.86**	**$6,998,305.05**	**$2,894,683.70**	**$0.00**	**1,002,433.46**	**1,187,912.65**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Allocation of Low Pressure Pipe**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		2,182,223	$18,204,991.88	$8.34				
4	All Pipe		12,114,210	217,938,408.22					
5	Unit Cost of 2" x All Pipe Footage			$101,032,511.40					
6	Customer Component			46.358%					
7	Demand Component			53.642%					
8	Allocable Low Pressure Pipe		$217,938,408.22						
9	Number of Customers (excl MDS)		188,289	172,366	15,903	0	19	1	
10	Percent Customers		100.000%	91.543%	8.446%	0.000%	0.010%	0.001%	
11	Customer Component		46.358%	42.438%	3.915%	0.000%	0.005%	0.000%	
12	Design Day Volumes (excl MDS)		285,850	224,300	59,495	0	2,053	2	
13	Percent Design Day Volumes		100.000%	78.468%	20.813%	0.000%	0.718%	0.001%	
14	Demand Component		53.642%	42.092%	11.165%	0.000%	0.385%	0.001%	
15	Minimum System Allocation Factor		100.000%	84.529%	15.080%	0.000%	0.390%	0.001%	
16	**Allocation of Low Pressure Pipe**		**$217,938,408.22**	**$184,221,157.09**	**$32,865,111.96**	**$0.00**	**849,959.79**	**2,179.38**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Allocation of Regulated Pressure Pipe Only**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		11,241,770	$109,347,870.64	$9.73				
4	All Pipe		22,157,625	379,849,758.16					
5	Unit Cost of 2" x All Pipe Footage			$215,593,692.42					
6	Customer Component			56.758%					
7	Demand Component			43.242%					
8	Allocable Regulated Pressure Only Pipe		$379,849,758.16						
9	Number of Customers (excl MDS)		134,665	122,867	11,589	0	163	46	
10	Percent Customers		100.000%	91.239%	8.606%	0.000%	0.121%	0.034%	
11	Customer Component		56 758%	51.785%	4.885%	0.000%	0 069%	0.019%	
12	Design Day Volumes (excl MDS)		277,730	139,100	71,149	0	35,828	31,653	
13	Percent Design Day Volumes		100.000%	50.085%	25.618%	0.000%	12.900%	11.397%	
14	Demand Component		43.242%	21.658%	11.078%	0.000%	5.578%	4.928%	
15	Minimum System Allocation Factor		100.000%	73.443%	15.963%	0.000%	5.647%	4.947%	
16	**Allocation of Regulated Pressure Only Pipe**		**$379,849,758.16**	**$278,973,057.88**	**$60,635,416.90**	**$0.00**	**21,450,115.84**	**18,791,167.54**	

COLUMBIA GAS OF PENNSYLVANIA, INC
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS B.ELLIOTT

Line No.	Description	Alloc	Total Company	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	**Allocation of Remaining Regulated Pressure Pipe**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		304,971	$3,413,324 59	$11.19				
4	All Pipe		5,385,168	160,511,271.80					
5	Unit Cost of 2" x All Pipe Footage			$60,260,027.09					
6	Customer Component			37 543%					
7	Demand Component			62.457%					
8	Allocable Remaining Regulated Pressure Pipe		$160,511,271.80						
9	Number of Customers (Total Company excl MDS)		418,439	381,074	36,801	0	466	98	
10	Percent Customers		100 000%	91.071%	8.795%	0.000%	0.111%	0.023%	
11	Customer Component		37.543%	34.191%	3.302%	0.000%	0.042%	0.009%	
12	Design Day Volumes (Total Company excl MDS)		791,995	458,700	189,733	0	65,702	77,860	
13	Percent Design Day Volumes		100 000%	57.917%	23.956%	0.000%	8.296%	9.831%	
14	Demand Component		62.457%	36.173%	14.962%	0.000%	5.181%	6.140%	
15	Minimum System Allocation Factor		100.000%	70.364%	18.264%	0.000%	5.223%	6.149%	
16	**Alloc. of Remaining Regulated Pressure Pipe**		**$160,511,271.80**	**$112,942,161.29**	**$29,315,778.68**	**$0.00**	**8,383,503.73**	**9,869,838.10**	
17	**Total Minimum System Allocation Factor**		**$770,382,773.04**	**$583,134,671.31**	**$125,710,991.24**	**$0.00**	**31,686,012.82**	**29,851,097.67**	
18			**100.000%**	**75.694%**	**16.318%**	**0.000%**	**4.113%**	**3.875%**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 – PAGE 3

INTANGIBLE PLANT - PAGE 3 (101-106-107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

UNDERGROUND STORAGE PLANT - PAGE 3 (101-106-107)

Accounts 350 through 355

Underground Storage Plant was allocated using Factor No. 25 – Sales and CHOICE Transportation activity for the twelve months ending December 31, 2015 reflecting its peaking support for sales and CHOICE customers.

DISTRIBUTION PLANT - PAGE 3 (101-106-107)

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 17 since these structures house measuring and regulating stations serving the larger customer groups only.

Account 376 – Mains

Non-directly assigned mains were allocated by rate schedule based on the weighting of design day and annual throughput, Factor No. 5, for the Peak and Average study. For the Customer-Demand study such investment was based on Factor No. 20 which provides a customer component based on a two inch "Minimum System" with the remaining portion assigned on design-day. For the Average study, Factor No. 5 and Factor No. 20 are

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

averaged to assign the Mains costs to the various rate schedules. Please see Exhibit BEE-2 for a detailed description of Factor Nos. 5 and 20.

Direct Mains

Mains for Main Line Delivery Service ("MLDS") were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Mains - Related Accts

Accounts related to/or supports the mains gas plant account were allocation on Factor No. 5 under the Peak and Average study, Factor No. 20 under the Customer-Demand study, and Factor No. 22 under the Average study since these accounts directly support the mains investment. The mains-related accounts generally include the follow gas plant accounts: 374.10, 374.20, 374.30, 374.40, 374.41, 374.50, 375.20, 375.31, 375.40, 375.80, 378.10, 378.20, 378.30, 379.10 and 379.11.

Direct Mains - Related Accts

Similar to Mains - Related Accounts above, these accounts support the mains that were directly assigned to MLDS and include accounts 374.40, 374.50, 375.40, and 378.20. Also, Direct – Mains, the amounts were identified from the Company's maps and accounting records and directly assigned.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 380 - Services

Account 380 - Services was assigned by rate schedule based on a direct assignment of the investment costs. A more detailed description of the study is contained in Exhibit BEE-2 the Development of Allocation Factors.

Account 380 – Direct Services

As with Mains, services for MLDS were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Accounts 381 and 382

Meters and Meter Installations were allocated using Factor No. 16, which was based on an actual inventory of meters installed on customer premises as explained in Exhibit BEE-2, the Development of Allocation Factors and Statement No. 7. This methodology represents virtually a direct assignment of costs to the various customer groups.

Accounts 383 and 384

House Regulators and House Regulator Installations were allocated using Factor No. 26, which was based on an actual inventory of house regulators installed on customer premises as explained in Exhibit BEE-2, the Development of Allocation Factors and Statement No. 7.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 385

Industrial Measuring and Regulating Stations were allocated using Factor No. 17, which was based on a review of Columbia's records as explained in Exhibit BEE-2, the Development of Allocation Factors. Measuring stations were segregated by rate schedule.

Dist Plant Excl Other Allocated

This investment consists of gas plant accounts 375.70, 375.71 and all 387 and was allocated to the various rate schedules using Factor No. 11. Factor No. 11 was based on distribution plant specifically assigned and was used to assign general investment and costs that support the distribution system.

General Plant

General plant includes items such as general tools (cars, trucks, backhoes, etc), communication equipment, office furniture and fixtures, and other miscellaneous equipment. Consistent with general distribution plant, this plant investment supports the delivery of natural gas. Therefore, Factor No. 11 was used to assign the investment.

RESERVE FOR DEPRECIATION - PAGE 4

Depreciation Reserve was calculated on an account by account basis using the same allocation factors that were used to allocate all gross plant accounts.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

DEPRECIATION & AMORTIZATION EXPENSE and NET NEGATIVE SALVAGE - PAGE 5

Depreciation and amortization expense was allocated by gas plant account on the same allocations as the Gross Original Cost. Amortization of net negative salvage was allocated using Factor 11 based on its remediation of distribution type facilities.

OPERATING REVENUE AT CURRENT AND PROPOSED RATES - PAGE 6

Sales and Transportation Revenue

Sales and transportation revenue was directly assigned as presented in Exhibit No. 103 for the fully forecasted rate year and supported by Company witness Lai.

Accounts 487

Forfeited discounts were allocated using Factor No. 10, which was developed from actual forfeited discounts billed by rate class during the historic test year twelve months ended November 30, 2014.

Accounts 488, 493 and 495

Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Rent Revenue was allocated using Factor No. 11 because the rent is derived mostly from the rent of company-owned office buildings, making the use of the Distribution Plant allocator appropriate.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully forecasted rate year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4, which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, since these costs benefit customers in the way that all other distribution costs provide benefit.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 871

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains since these are costs incurred monitoring and directing the flow of gas through the distribution system.

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator ("M&R") Station Equipment – Industrial ("IND") were allocated using Factor No. 17 – Direct Assignment – IND M&R - since these costs are incurred in direct association with the stations in Account 385.

Accounts 878 and 879

Meters and House Regulators Expenses were allocated using Factor No. 27, which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Exhibit BEE-2, the Development of Allocation Factors, and Statement No. 7. Expenses for Customer Installations were allocated using Factor No. 15 because these expenses are related to the installation of customer service lines.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

DISTRIBUTION EXPENSES – MAINTENANCE - PAGE 7

Accounts 885 and 894

General costs for supervision and engineering and maintenance costs of other equipment of the distribution function were allocated using Factor No. 18 other distribution expense since these costs benefit customers in the same way that all other distribution costs provide benefit.

Account 886

Structures and Improvements Expense was allocated using Factor No. 13, reflecting the spread of Account 376 Mains among all customer classes, because these plant and expense functions are directly related.

Account 887

Mains Maintenance Expense was allocated using Factor No. 13, which reflects the spread of Account 376 Mains among all customer classes, since plant and expense functions are directly related.

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 - Direct Assignment – IND M&R - since these costs are incurred in direct relation with the stations in Account 385.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 892

Expenses for Services were allocated using Factor No. 15 which was based on size of service and size of customer as explain above under Gas Plant Account 380 – Services and in Statement No. 7.

Account 893

Meters and House Regulators Expenses and Customer Installations were allocated using Factor No. 27 which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Exhibit BEE-2, the Development of Allocation Factors, and Statement No. 7. This methodology represents virtually a direct assignment of costs to the various customer classes.

CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES EXPENSES - PAGE 8

Account 904 – Uncollectibles – DIS Revenue & Uncollectibles GMB/GTS Revenue

These cost categories represent traditional bad debts. They have been separated between the two classes of customers and allocated based on the historical charge-offs and revenue, related to each, as included in Factor No. 7 for DIS and Factor No. 8 for GMB/GTS, respectively.

Account 904 Uncollectibles – Unbundled

These costs were directly assigned to each rate schedule consistent with the levels included in revenue for the fully forecasted rate year as presented in Exhibit No. 103. Factor No. 23 reflects this assignment.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 904 – Direct USP Uncollectibles

These uncollectibles are directly related to the Company's Customer Assistance Program available to residential customers and are recoverable from the residential class whether sales or delivery service. The amounts shown are reflected in revenue for the fully forecasted rate year as presented in Exhibit No. 103.

Customer Accounts

Customer Accounts include meter reading, customer records, and credit and collection activities recorded in accounts 901 through 903, 905, and 921. These costs were allocated using Factor No. 6, Average Number of Customers, since they are directly related to the number of customers served. Interest on Customer Deposits was allocated using Factor No. 9 because the interest is directly related to the amount of customer deposits.

Customer Service Information

Customer Service and Informational Costs are reflected in accounts 907 through 910 plus related costs in 921 and 931. These costs were allocated using Factor No. 6 since all customers may benefit except account 908 – Direct USP/LIURP/HEEP. These costs include the recovery of specific customer programs benefiting residential customers. The amounts reflect the recovery included in revenue as presented in Exhibit No. 103 for the fully forecasted rate year. Account 910, Large Customer Relations, was allocated using Factor No. 21 which is based on the number of accounts managed by this group.

Sales Expense

Sales expenses, accounts 912 and 913, were allocated using Factor No. 6, Average Number of Customers, since these activities directly support customers served.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8

Admin. & General Expenses (Line 33)

General Office Expenses, and to a lesser degree, District and Local Office Expenses in this function classification, plus company-wide expenses excluding Employee Benefits, account 926, such as Injuries and Damages, Insurance, and Regulatory Commission Expense were all allocated using Factor No. 19 - Total Operation & Maintenance Excluding Gas Purchased, A & G, Uncollectibles and USP rider costs. These costs are regarded as overhead to the entire company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. Employee Pensions & Benefits, account 926, was allocated on Factor No. 24, Labor, since they are directly related to company labor.

TAXES OTHER THAN INCOME - PAGE 9

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 11 - Distribution Plant excluding Other due to a direct relationship with Plant in Service. Similarly, PA Capital Stock and License and Franchise Taxes were allocated using Factor No. 11 as they are also related to Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly, have been allocated based on Factor No. 24 – Labor. State Sales and Use Tax and Other Taxes were allocated using Factor 19 since these taxes are generally related to the purchase of supplies.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

RATE BASE SUMMARY - PAGE 10

Account 154

Materials and Supplies were allocated based on Factor 11, Distribution Plant Excluding Other, reflecting the primary future use of such inventory.

Account 164 & 117

Gas Stored Underground, both current and long term, was allocated based on Factor No. 25, Sales and CHOICE Transportation, reflecting the support of these customers in meeting their design day and seasonal requirements.

Account 165

Prepayments consist primarily of commission fees and corporate insurance. Therefore, these costs were allocated using Factor 19, Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs.

Accounts 190, 282 and 283

All deferred income taxes included in rate base are plant related and, therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor 9, Direct Assignment – Customer Deposits.

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 11 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustments over book are plant related, i.e., tax depreciation over book depreciation. Therefore, the tax deductions were allocated using Factor No. 12, Gross Plant.

In calculating the Federal and State income taxes for each rate schedule, the effective Federal and State income tax rates were used. Income taxes were calculated for each customer class.

Columbia Gas of Pennslyvania, Inc.
Intra Class Adjustment from SGDS to SGSS and SCD at Proposed ROE of 10.95%
For the 12 Months Ending December 31, 2016

Ln. No.	Item	Total	RSS/RDS	SGSS/SCD/SGDS	N/A	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,794,693	2,619,173	1,170,511	-	-	-	5,009
2	Account 164	58,489,294	40,370,481	18,041,608	-	-	-	77,206
3	Allocated Storage Per ACOS Study using Allocation Factor #25	62,283,987	42,989,654	19,212,119	-	-	-	82,215
4	Sales & CHOICE Transportation (Dth)	49,155,214.1	33,927,676.1	15,162,538.0	0.0	0.0	0.0	65,000.0
5	Factor 25 Allocation of Storage	100%	69.022%	30.846%	0.000%	0.000%	0.000%	0.132%
6	Pre-Tax as Filed	12.190%	12.190%	12.190%	12.190%	12.190%	12.190%	12.190%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	7,592,418	5,240,439	2,341,957	-	-	-	10,022
8	Rate Per Dth	0.1545						

Ln. No.		Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
13	SGSS - Subject to Storage	9,128,567.8	60.290%	1,411,966	0.8095	483,622
14	SCD - Subject to Storage	2,149,044.4	14.190%	332,324	0.1905	113,811
15	SGDS - Not Subject to Storage	3,862,725.8	25.510%	597,433		(597,433)
		15,140,338	100.000%	2,341,957		-

COLUMBIA STATEMENT NO. 8

COLUMBIA GAS OF PENNSYLVANIA, INC.

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2015-2468056

March 19, 2015

Columbia Gas of Pennsylvania, Inc.
Direct Testimony of Paul R. Moul
Table of Contents

Page No.

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS 1

NATURAL GAS RISK FACTORS 6

FUNDAMENTAL RISK ANALYSIS 12

CAPITAL STRUCTURE RATIOS 19

COSTS OF SENIOR CAPITAL 21

COST OF EQUITY – GENERAL APPROACH 22

DISCOUNTED CASH FLOW ANALYSIS 23

RISK PREMIUM ANALYSIS 38

CAPITAL ASSET PRICING MODEL 42

COMPARABLE EARNINGS APPROACH 48

CONCLUSION ON COST OF EQUITY 51

Appendix A - Educational Background, Business Experience and Qualifications

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CEG	Columbia Energy Group
CPA	Columbia Gas of Pennsylvania, Inc.
DCF	Discounted Cash Flow
FFO	Funds from Operations
FOMC	Federal Open Market Committee
FFRY	Fully Forecasted Rate Year
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Companies
LEI	Leading Economic Indicators
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
MLPs	Master Limited Partnerships
P-E	Price-earnings
PPUC	Pennsylvania Public Utility Commission
PUHCA	Public Utility Holding Company Act of 2005
PUC	Public Utility Commission
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
WNA	Weather Normalization Adjustment Mechanism

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PPUC" or the "Commission") should recognize in the determination of the revenues that Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit No. 400, which is a multi-page document divided into fourteen (14) schedules.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A. Based upon my analysis of the Company and the superior performance of its management, as described in the testimony of Mr. Mark R. Kempic, President of the Company (Columbia Statement No. 1), it is my opinion that the rate of return on common equity should be set at 10.95%. As shown on page 1 of Schedule 1, I have presented the weighted average cost of capital for the

Company, which is calculated with the December 31, 2016 Fully Forecasted Rate Year ("FFRY"). The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.65%	5.31%	2.27%
Short Term Debt	5.14%	2.86%	0.15%
Total Debt	47.79%		2.42%
Common Equity	52.21%	10.95%	5.72%
Total	100.00%		8.14%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of NiSource Gas Distribution Group, which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, and other energy investments.

The Company provides natural gas distribution service to approximately 421,000 customers located in south-central and western

Pennsylvania. Throughput to its customers for the twelve-months ended November 30, 2014 was represented by approximately 43% to sales customers and approximately 57% to transportation customers. CPA obtains its gas supplies from producers and marketers and has transportation arrangements through connections with six interstate pipelines. The Company has storage arrangements with three suppliers to supplement flowing gas.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 10.95%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to

raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of nine (9) gas companies. The companies are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. Please explain the selection process used to assemble the Gas Group?

A. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of eleven companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. Through the application of my screening process, I eliminated two companies, which were NiSource and UGI Corporation. The eliminations were attributed to operational differences and diversification, as identified in page 2 of Schedule 3. The remaining nine companies are included in my Gas Group.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

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[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF		10.05%
RP		11.75%
CAPM		11.90%
CE		13.55%

As I will discuss later, CPA has more risk than the Gas Group attributed to its weaker credit quality, its smaller size, and other factors. To the extent that these higher risk factors can be quantified, they are reflected in the results shown above. From these measures, I recommend a cost of equity of 10.95% with recognition of the exemplary performance of the Company's management. Mr. Kempic has shown that the Company ranks high in

customer service and management efficiency. In recognition of its outstanding performance, the Company should be granted an opportunity to earn a 10.95% rate of return on common equity. The 10.95% rate of return on common equity, which includes 25 basis points for recognition of the exemplary performance of the Company's management, is well with the range of the market-based measures (i.e., DCF, RP and CAPM) of the cost of equity that extend up to 11.90% (the results of the Comparable Earnings method is higher). To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Indeed, in a study dated December 9, 2008, prepared for the American Gas Foundation, it was noted that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. Furthermore, the report specifically found that returns below 10% would trigger broad disenchantment with LDC investment.[2]

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for

[2] American Gas Foundation, Regulatory Policy of Return on Equity [Review and Analysis of the Natural Gas Utility Sector] (2008)

the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Mr. Kempic and other Company witnesses discuss the investments that the Company will make to address these issues.

The Company also faces a series of risks that impact its cost of equity. In the western area of Pennsylvania, the Company operates in a unique situation with overlapping service territories, which enable other gas utilities to compete with one another for customers. Further, there are six interstate pipelines that traverse the Company's service territory. This situation exposes the Company to bypass for certain large volume customers. Finally, the existence of local gas production provides a bypass threat to the Company. This situation will only become more intense with increasing production from the Marcellus Shale formation. Indeed, the Commission has established a generic proceeding (Docket No. I-2012-2320323) to investigate the issues of NGDC competition in Pennsylvania. CPA has actively participated in that proceeding. The Commission has not yet issued a decision in the case. It is not possible to determine at this time what effect a decision may have on continued service to these customers with competitive options. In addition, with the consolidation of several formerly competing LDCs in western

Pennsylvania, CPA could potentially face additional threats from the stronger LDC competitor that remains. Overall, the Company's risk of competition is considerably higher than that faced by many LDCs, including the members of the Gas Group that I used to measure the Company's cost of equity.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To deal with this issue, CPA has a weather normalization adjustment mechanism ("WNA") as part of its tariff. The WNA is applicable only to residential customers, and has a 5% deadband. This means that the Company's revenues continue to be subject to variation due to weather, albeit less than formerly. I am advised that in the first year of operation, the Company refunded approximately $9.36 million to customers under the WNA. This tariff provision will function as a pilot program during a minimum three-year period that continues until a final order in the first rate case that is filed after May 31, 2016.

Q. Does your cost of equity analysis and recommendation take into account the WNA rate design that the Company is using?

A. Yes. The Company operates with a WNA tariff provision on a pilot basis. All but one company in my Gas Group has some form of WNA mechanism. The

sole exception is Laclede Gas, which has a weather mitigated rate design that recovers its fixed costs more evenly during the heating season. Therefore, the market prices of the companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a WNA mechanism. Therefore my analysis reflects the impacts of WNA on investor expectations through the use of market-determined models. If the Company is unable to continue with its WNA rate design beyond 2016, its risk will increase above that of the Gas Group that serves as a basis to measure the Company's cost of equity, i.e., the Gas Group's cost of equity will then understate the return that is appropriate for the Company.

Q. Are you aware that there is a DSIC available to natural gas and electric utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company has utilized the DSIC for certain periods of time in the past, and that it may be able to use it in the future. The cost of capital for CPA, however, is not be affected by the DSIC. I say this because most of the proxy group companies (i.e., seven of nine companies) whose data has been used to develop the cost of equity for CPA in this proceeding have a DSIC or similar infrastructure rehabilitation mechanisms. Indeed, AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas and South Jersey Industries make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group. The

DSIC represents a positive step that will align the Company with many of the companies that make up my proxy group.

Q. How does the Company's throughput to large volume users or those with competitive alternatives affect its risk profile?

A. The Company's risk profile is influenced by natural gas delivered to its large industrial and commercial customers and those customers with competitive alternatives, as demonstrated by the fact that gas throughput to the Company's 176 major account customers represents approximately 29% of the Company's total throughput. In addition, the ten largest customers by volume represent approximately 10.2 million Dth of throughput during the twelve months ended November 30, 2014. Generally speaking, there are four primary threats to throughput to the Company's largest volume users. First, the Company can and has experienced attrition in this large customer group. Second, the Company's largest customers, which have traditionally used transportation service, have the ability to bypass the Company's system to other gas supply sources such as interstate pipelines, other local distribution companies, or nonregulated pipeline contractors providing access to local supplies. In this regard, the Company has identified 19.4 million Dth per year of customer throughput that is susceptible to such bypass. Of course the number that CPA has identified is only a subset of the total load at risk since it is almost certain that the Company has not identified all customers who have competitive alternatives. Third, in addition to the bypass threat, a material portion of the large customer throughput is also exposed to fuel switching to coal, oil, propane, bio fuels, or other energy sources depending on the

fluctuating costs of these different fuels in comparison with natural gas. Finally, in its effort to retain load, the Company is vulnerable to the impacts of business cycles, competition within its customers' industries, and other external factors that can result in shifts of production to customer facilities that are not served by the Company. All of these risks put fixed cost recovery for this class of customers at risk.

Q. Please indicate how the Company's construction program affects its risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. Although the Company has made significant strides in reducing its percentage of cast iron and unprotected steel pipe, these facilities still represent 1,631.9 miles (or approximately 22%) of its distribution mains as of year-end 2014. The Company also has 56,770 (or approximately 13%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2015	$196,872,000
2016	$210,572,000
2017	$230,803,000
2018	$224,523,000
2019	$218,856,000
Total	$1,081,626,000

The Company's total capital expenditures over the next five years will represent approximately 85% ($1,081,626,000 ÷ $1,269,694,248) of the net utility plant in service at December 31, 2014.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular CPA?

A. The Commission should recognize and take into account the need to replace infrastructure and the competitive environment in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. A fair rate of return also represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on reasonable terms.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and

qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed previously. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the gas group?

A. My Gas Group consists of the following companies: AGL Resources, Inc., Atmos Energy Corp., Laclede Group, Inc., New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing

cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The Company obtains its external capital not funded by internal sources from NiSource Finance Corp. Presently, the NiSource credit quality ratings are Baa2 from Moody's Investors Service ("Moody's") and BBB- from Standard & Poor's Corporation ("S&P"). These ratings for NiSource represent the Long Term ("LT") issuer rating by Moody's and the corporate credit rating ("CCR") designation by S&P, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself.

For the Gas Group, the average LT issuer rating is A2 by Moody's and the average CCR is A- by S&P, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by S&P, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2009-2013. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the

S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[3]

There are no market ratios available for the Company because its stock is owned by NiSource. The five-year average price-earnings multiple was similar for the Gas Group and to the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat higher for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower

[3]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 54.9% for CPA, 55.4% for the Gas Group, and 45.3% for the S&P Public Utilities. The common equity ratios were similar for CPA and the Gas Group, thereby indicating similar financial risk.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.140 (1.7% ÷ 12.1%) for the Company, 0.077 (0.8% ÷ 10.4%) for the Gas Group, and 0.102 (1.0% ÷ 9.8%) for the S&P Public Utilities. The variability of the Company's rates of return was higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[4] The five-year average operating ratios were 86.4% for the Company, 87.7% for the Gas Group, and 81.7% for the S&P Public Utilities. The Company's operating ratios were not appreciably different from the Gas Group.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense)

[4]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 3.47 times for the Company, 4.45 times for the Gas Group, and 3.09 times for the S&P Public Utilities. The average interest coverages were highest for the Gas Group, followed by CPA and the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 74.7% for the Company, 91.3% for the Gas Group and 90.6% for the S&P Public Utilities. The Company's average IGF to construction percentage has lagged that of the Gas Group, thereby signifying higher risk created by the greater need to raise capital externally.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[5] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.78 as the average for the Gas Group (see page 2 of Schedule 3) and 0.77 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation.

A. In several aspects, principally related to its smaller size, its more variable equity returns, and its lower IGF to construction, CPA's risk is higher than the Gas Group. The bond rating of NiSource, the Company's ultimate parent, is below that of the Gas Group, which indicates higher credit quality risk. Its common equity ratio and operating ratio have been fairly similar to the Gas Group. On balance, the cost of equity measured with the Gas Group data will provide an understatement of the Company's cost of equity, due principally to the lower credit quality of the CPA's parent company.

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[5]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for CPA.

A. In this case, the capital structure ratios of CPA have been proposed to calculate the rate of return. I will show that the Company's capital structure ratios proposed in this case are reasonable. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed.

Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2014 capitalization corresponds with the end of the historic test year in this case. The November 30, 2015 capital structure is estimated at the end of the future test year, and the December 31, 2016 capital structure is estimated at the end of the fully forecasted rate year. Prior to the end of the fully forecasted rate year, the Company plans to issue $195.000 million of new long-term debt, a portion of which will be used to redeem at maturity $65.875 million of long-term debt. Of these amounts, $30.000 million was actually issued on December 18, 2014 and $60.000 million will be issued in March 2015. The maturities will occur in November of 2015 and 2016 and additional new issues will occur in September 2015 and March 2016. Pursuant to Paragraph 26 of the approved settlement in Columbia's 2014 base rate case (Docket No. R-2014-2406274), I am including, as Exhibit PRM-1 to my testimony, the Treasury Yield as reported in the Federal Reserve Statistical Release, H. 15 Selected Interest Rates and

the yield spread as reported by Reuters Corporate spreads as of the December 2014 debt issuance.

Q. How do the capital structure ratios compare for CPA and the Gas Group?

A. I have verified the reasonableness of the Company's common equity ratio by considering the historical comparison to the Gas Group. For the historical comparison, the Gas Group had a 54.0% common equity ratio at year-end 2013 calculated without short-term debt. Over the past five years, the average common equity ratio for the Gas Group has been 54.0% to 56.7%. My comparison of these ratios rests on a calculation without short-term debt because the Company uses a twelve-month average for ratesetting purposes, while the GAAP financial reports for the Gas Group use fiscal year-end balances of short-term debt. For the Company, its FFRY common equity ratio is 55.0% ($661,674,000 ÷ $1,202,189,000) computed without short-term debt, thereby indicating that the Company's common equity ratio is reasonable.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the fully forecasted rate year. As a result, I will adopt the Company's fully forecast rate year capital structure ratios of 42.65% long-term debt, 5.14% short-term debt and 52.21% common equity at December 31, 2016. For short-term debt, I have used a twelve-month average for the fully forecasted rate year. These capital structure ratios are the best approximation of the mix

of capital the Company will employ to finance its rate base during the period new rates are in effect.

COSTS OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of CPA's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of debt at November 30, 2014. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of debt at November 30, 2015. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2016. For the new issues of long-term debt, I have used a cost of 4.16% for the issue in March 2015, 4.21% for the issue in September 2015, and 4.22% for the issue in March 2016. These rates compare to the 4.43% that the Company paid to obtain debt in December 2014.

I will adopt the 5.31% embedded cost of long-term debt at December 31, 2016, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 42.65% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. I have used a cost of short-term debt of 2.86%, which represents the Company's estimate for the fully forecast rate year. The Company obtains its

short-term debt from the NiSource money pool, which has a credit facility with a syndicate of banks. The interest rate is established as the one-month LIBOR plus 127.5 basis points. Hence, the Company's estimate is comprised of the 1.583% LIBOR plus the spread, i.e., 1.583% + 1.275% = 2.858%, or rounded to 2.86%.

Q. What overall debt cost rate have you determined for rate of return purposes?

A. As shown on page 3 of Schedule 6, the combined cost of long- and short-term debt is 5.05% for the fully forecast rate year.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for CPA.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPA, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly

restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a rate of return on common equity of 10.95%, which includes recognition of the exemplary performance of the Company's management as explained by Mr. Kempic.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k = D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF

equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 10.05%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for future returns depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. The monthly dividend yields for the twelve months ended December 2014 are shown on Schedule 7 and capture an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2014, the average dividend yield was 3.52% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields

[6]Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

for the more recent six- and three-month periods were 3.48% and 3.33%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.48% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds nine basis points to the six-month average historical yield, thus producing the 3.58% adjusted dividend yield for the Gas Group.

Q. Turning to the growth component of the DCF analysis, please explain the underlying factors that influence investors' growth expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flows stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely

available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state"

growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. It is quite apparent that the Company is going through an expansion stage, because of substantial new investment.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the proxy group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. The historical growth rates were taken from the Value Line publication that provides this data. As shown on Schedule 8, the historical growth of earnings per share was in the range of 2.78% to 5.22% for the Gas Group.

Schedule 9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The

IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Gas Group.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.11% by IBES/First Call, 5.11% by Zacks, 5.19% by Morningstar, 5.04% by SNL, and 6.94% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 6.94%) than the dividends per share (i.e., 4.44%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts. Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron

Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[7] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 5.04% to 6.94%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is a reasonable growth rate before consideration of increased growth rate for Columbia generated by accelerated investment in infrastructure. For the Gas Group, the annual average forecast capital expenditures will represent 11.8% of its existing net plant. For CPA, the equivalent percentage is 19.6%. This means that the Company will experience more growth prospectively than is indicated for the Gas Group. Thus, the Gas Group's future growth rate will understate the growth for CPA. In addition, projected growth rates are likely understated because they do not fully recognize the growth in earnings that will occur due to the substantial increase in plant investment. Growth rates today should reflect the expectation of growth generated by accelerated investment in infrastructure by public utilities. Moreover, the stock market is one of the ten components of the Leading Economic Indicators ('LEI") compiled by The

[7] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

Conference Board. The LEI is designed to signal peaks and troughs in the business cycle. "In the six-month period ending September 2014, the leading economic index increased 3.5 percent (about a 7.1 percent annual rate), faster than the growth of 2.7 percent (about a 5.6 percent annual rate) during the previous six months. Also, the strengths among the components became more widespread than weaknesses in the past six months."[8] This improving economic growth argues for a higher DCF growth rate.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 34.27% long-term debt, 0.11% preferred stock, and 65.62% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q. Please explain why.

A. If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital based on a book value capital structure used for ratesetting purposes, the utility will not, by definition, recover its risk-adjusted capital cost. This is because market valuations of equity are based on market value

[8]The Conference Board U.S. Business Cycle Indicators -The Conference Board Leading Economic Index (LEI) for the U.S. and Related Composite Economic Indexes for September 2014 [Press Release].Retrieved from http://www.conference-board.org/data/bci.cfm dated October 23, 2014.

capital structures, which in general have more equity and less debt and therefore reflect less risk than book value capital structures (see Schedule 10 for the comparison). The utility's risk-adjusted cost of equity will necessarily be lower with the less risky market value capital structure than with the book value capital structure. The difference represents that portion of the utility's cost of equity that it will not recover unless either the market value cost of equity is applied to the utility's market value capital structure or it is adjusted to reflect the higher risk associated with the book value capital structure. By the same token, if the utility's market value capital structure is less than its book value structure, then the utility's market cost of equity should be adjusted downward to reflect the lower risk associated with the book value capital structure, or else the utility will over-recover its total cost of equity.

This shortcoming of the DCF has persuaded the Commission to adjust the DCF determined cost of equity upward to make the return consistent with the book value capital structure. Specific adjustments to recognize this risk difference were made in the following cases:

Date	Company	Docket Number	Basis Points
January 10, 2002	Pennsylvania-American Water Co.	Docket No. R-00016339	60 basis points
August 1, 2002	Philadelphia Suburban Water Co.	Docket No. R-00016750	80 basis points
January 29, 2004	Pennsylvania-American Water Co.	Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004)	60 basis points
August 5, 2004	Aqua Pennsylvania, Inc.	Docket No. R-00038805	60 basis points
December 22, 2004	PPL Electric Utilities Corp.	Docket No. R-00049255	45 basis points
February 8, 2007	PPL Gas Utilities Corp.	Docket No. R-00061398	70 basis points

In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification.

Q. Is your leverage adjustment dependent upon the market valuation or book valuation from an investor's perspective?

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of

capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 7.63% when applicable to a capital structure with 100% common equity.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment, which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. Simply stated, the leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. There can be no

dispute that a firm's financial risk varies with the relative amount of leverage contained in its capital structure.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.63%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 1.91% compensation for having a 45.53% debt ratio, plus 0.01% for having a 0.17% preferred stock ratio. The sum of the parts is 9.55% (7.63% + 1.91% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I

summed the 3.58% dividend yield, the 5.25% growth rate, and the 0.72% for the leverage adjustment in order to arrive at the same 9.55% (3.58% + 5.25% + 0.72%) return. I know of no means to mathematically solve for the 0.72% (9.55% - 8.83%) leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.72% adjustment is merely a convenient way to compare the 9.55% return computed directly with the Modigliani & Miller formulas to the 8.83% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1 / P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	*lev.*	=	K
Gas Group	3.58%	+	5.25%	+	0.72%	=	9.55%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. For this reason, the DCF cost rate I have developed for the Gas Group understates the cost of equity. As noted previously, CPA has weaker credit quality as compared to the Gas Group. A generally accepted tenet of corporate finance is that risk and return are linked. Here, weaker credit quality adds to risk. As a consequence, an upward adjustment to the DCF results is required to accommodate the risk of CPA vis-á-vis the Gas Group.

Q. What is the adjustment to recognize the weaker credit quality of CPA?

A. The DCF returns that are produced for the Gas Group relate to the average credit quality of that group, which is A2/A- as shown on page 2 of Schedule 3. In order to provide recognition of the additional return that is required to compensate CPA for its higher risk in this regard, I have reviewed the difference in yields on A-rated and Baa-rated public utility debt. The yield difference is related to the additional return required when risk increases, i.e., generally bond yields increase as credit quality declines. The yield difference

between A-rated and Baa-rated public utility bonds is used as a proxy for quantifying this additional risk.

As shown by the data presented on page 1 of Schedule 11, the difference in yields between Baa-rated and A-rated public utility bonds was 0.58% (4.70% - 4.12%) for the six-months ended December 2014. Based on this difference in yields, I propose that a one-half percentage point (i.e., the interest rate difference rounded to 0.50%) be added to the DCF calculation for the Gas Group to provide recognition for the higher risk of CPA due to its weaker credit quality risk. As such, the DCF return requires adjustment to 10.05% (9.55% + 0.50%) to recognize the higher risk of CPA.

I also note that the 5.25% growth rate for the gas group understates growth for CPA, given CPA's significantly higher projected construction program. This suggests that other equity cost rate models should be given weight in arriving at the cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.75% including the credit quality adjustment. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations,

including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, a 4.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2014, and a yield spread of 1.00%, derived from historical data.

Q. What historical data have you analyzed?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended December 2014, the average monthly yield on Moody's index of A-rated public utility bonds was 4.28%. For the six and three-month periods ended

December 2014, the yields were 4.12% and 4.03%, respectively. During the twelve-months ended December 2014, the range of the yields on A-rated public utility bonds was 3.95% to 4.63%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 10, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 0.94% on a twelve-month average basis, 1.00% on a six-month average basis, and 1.06% on a the three-month average basis. From these averages, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. How have you used these data to project the yield on a-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2015	First	4.0%	4.9%	3.1%	1.00%	4.10%
2015	Second	4.2%	5.1%	3.3%	1.00%	4.30%
2015	Third	4.3%	5.3%	3.5%	1.00%	4.50%
2015	Fourth	4.6%	5.5%	3.7%	1.00%	4.70%
2016	First	4.8%	5.7%	3.9%	1.00%	4.90%
2016	Second	5.0%	5.8%	4.0%	1.00%	5.00%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2014 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2016-20	5.8%	6.6%	4.9%
2021-25	6.1%	7.0%	5.1%

Given these forecasted interest rates, a 4.75% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity Risk Premium have you determined for this case?

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2014 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 11.

Common Equity Risk Premiums	
Low Interest Rates	7.60%
Average Across All Interest Rates	5.79%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.60% when the marginal cost of long-term government bonds was low (i.e., 3.01%, which was the average yield during periods of low rates). Conversely,

when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.79% when the average government bond yield was 5.15%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.60% premium related to periods of low interest rates and the 5.79% premium related to average interest rates across all levels.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Gas Group	4.75%	+	6.50%	=	11.25%

As I noted previously, NiSource carries a Baa2/BBB- rating on its debt. This means that the Risk Premium cost rate shown above would understate the Company's cost of equity by one-half percentage point, because the 11.25% shown above is based on the yield on A-rated public utility debt. As such, the Risk Premium cost rate for CPA is 11.75% (11.25% + 0.50%).

CAPITAL ASSET PRICING MODEL

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 11.90%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return (*"Rf"*), the beta measure of systematic risk (*"β"*), and the market risk premium (*"Rm-Rf"*) derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.78 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[9] as follows:

[9]Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth

$$\beta l = \beta u\,[1 + (1 - t)\,D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.58 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.90 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.90 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2014, the average yield on 30-year Treasury bonds was 3.34%. For the six- and three-months ended December 2014, the yields on 30-year Treasury bonds were 3.12% and 2.97%, respectively. During the twelve-months ended December 2014, the range of the yields on 30-year Treasury bonds was 2.83% to 3.77%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The

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Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452.

resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. In 2014, the FOMC began reducing its bond purchasing program. The term commonly used to describe this reduction in bond purchases is called "tapering." The FOMC completed its tapering program by ending its quantitative easing in October 2014. As shown on page 2 of Schedule 12, forecasts published by Blue Chip on January 1, 2015 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.1% to 4.0% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.9% from 2016 through 2020 and 5.1% from 2021 to 2025. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent yields on long-term Treasury bonds.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.17% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.01% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 12.11% (12.17% + 12.05% = 24.22% ÷ 2) and the average yield on long-term government bonds of 4.08% (3.01% + 5.15% = 8.16% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.03% (12.11% - 4.08%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated a 10.88% total market return from the Value Line data and a DCF return of 11.72% for the S&P 500. With the average forecast return of 11.30% (10.88% + 11.72% = 22.60% ÷ 2), I calculated a market premium of 7.55% (11.30% - 3.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 7.79% (7.55% + 8.03% = 15.58% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[10] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,561 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.14%, as shown on page 3 of Schedule 13.

Q. What CAPM result have you determined?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.90 for the Gas Group, the 7.79% market premium, and the 1.14% size adjustment, I derived the following CAPM-indicated cost of equity:

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Gas Group	3.75%	+	0.90	x (	7.79%	) +	1.14%	=	11.90%

[10]See Fundamentals of Financial Management, Fifth Edition, at 623.

While I have adjusted for the size of the Gas Group, the Company's risk is even greater because it is smaller than the Gas Group.

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one-century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification

that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. How have you implemented the Comparable Earnings Approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the

companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not

contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The historical rate of return on book common equity was 13.5% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The forecast rates of return as published by Value Line are shown by the 13.6% also using values less than 20%, as provided on page 2 of Schedule 13. Using these data my Comparable Earnings result is 13.55%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of the variety of methods and models described previously, I recommend that the Commission set the Company's rate of return on common equity at 10.95%. The proposed rate of return on common equity of 10.95% would provide recognition of the exemplary performance of the Company's management and the high quality of service provided to its customers as explained in the testimony of Mr. Kempic. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of

rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

Selected Interest Rates (Daily) - H.15

Daily Update

Release Date: December 19, 2014

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site. If Monday is a holiday, the weekly release will be posted on Tuesday after the holiday and the daily update will not be posted on that Tuesday.

December 19, 2014
Selected Interest Rates

Yields in percent per annum

Instruments	2014 Dec 15	2014 Dec 16	2014 Dec 17	2014 Dec 18
Federal funds (effective) [1] [2] [3]	0.11	0.12	0.13	0.13
Commercial Paper [3] [4] [5] [6]				
Nonfinancial				
1-month	0.08	0.09	0.13	0.12
2-month	0.10	0.10	0.14	0.14
3-month	0.11	0.12	0.14	0.17
Financial				
1-month	n.a.	0.09	0.09	n.a.
2-month	0.15	0.12	0.14	n.a.
3-month	0.16	0.15	0.16	0.15
Eurodollar deposits (London) [3] [7]				
1-month	0.17	0.17	0.17	0.17
3-month	0.24	0.24	0.24	0.30
6-month	0.36	0.36	0.36	0.35
Bank prime loan [2] [3] [8]	3.25	3.25	3.25	3.25
Discount window primary credit [2] [9]	0.75	0.75	0.75	0.75
U.S. government securities				
Treasury bills (secondary market) [3] [4]				
4-week	0.02	0.03	0.03	0.04

3-month	0.04	0.03	0.03	0.04
6-month	0.11	0.11	0.11	0.12
1-year	0.21	0.20	0.22	0.24
Treasury constant maturities				
Nominal [10]				
1-month	0.02	0.03	0.03	0.04
3-month	0.04	0.03	0.03	0.04
6-month	0.11	0.11	0.11	0.12
1-year	0.22	0.21	0.23	0.25
2-year	0.60	0.58	0.62	0.67
3-year	1.03	0.99	1.06	1.10
5-year	1.58	1.53	1.61	1.68
7-year	1.90	1.85	1.93	2.01
10-year	2.12	2.07	2.14	2.22
20-year	2.45	2.40	2.46	2.54
30-year	2.74	2.69	2.74	2.82
Inflation indexed [11]				
5-year	0.41	0.32	0.39	0.48
7-year	0.47	0.38	0.44	0.56
10-year	0.50	0.42	0.49	0.57
20-year	0.69	0.62	0.67	0.77
30-year	0.84	0.77	0.81	0.91
Inflation-indexed long-term average [12]	0.70	0.62	0.67	0.77
Interest rate swaps [13]				
1-year	0.40	0.39	0.40	0.42
2-year	0.82	0.79	0.80	0.86
3-year	1.21	1.18	1.19	1.27
4-year	1.51	1.47	1.49	1.58
5-year	1.71	1.68	1.69	1.80
7-year	1.99	1.95	1.96	2.09
10-year	2.25	2.21	2.21	2.35
30-year	2.73	2.68	2.67	2.78
Corporate bonds				
Moody's seasoned				
Aaa [14]	3.70	3.70	3.75	3.80

Baa	4.68	4.67	4.74	4.78
State & local bonds [15]				3.65
Conventional mortgages [16]				3.80

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.

10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.

11. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treasury.gov/resource-center/data-chart-

center/interest-rates/.

12. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.

13. International Swaps and Derivatives Association (ISDA®) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. Eastern time by Thomson Reuters and published on Thomson Reuters Page ISDAFIX®1. ISDAFIX is a registered service mark of ISDA®. Source: Thomson Reuters.

14. Moody's Aaa rates through December 6, 2001, are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only. Data obtained from Bloomberg Finance L.P.

15. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations. Data obtained from Bloomberg Finance L.P.

16. Contract interest rates on commitments for 30-year fixed-rate first mortgages. Source: Primary Mortgage Market Survey® data provided by Freddie Mac.

Note: Weekly and monthly figures on this release, as well as annual figures available on the Board's historical H.15 web site (see below), are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886).

Description of the Treasury Nominal and Inflation-Indexed Constant Maturity Series

Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3, and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10, 20, and 30 years.

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Monday, December 22 2014 08:32 AM

Bond$$ Available Balance $95.00

Security Prices

Interest Rates/Spreads

Documents

REQUEST DATA

Estimated Cost: $35.00
Actual Cost: $35.00

REUTERS CORPORATE BOND SPREAD TABLES

Reuters Corporate Spreads for Utilities
12/18/2014

Rating	1 yr	2 yr	3 yr	5 yr	7 yr	10 yr	30 yr
Aaa/AAA	10	14	19	26	37	51	70
Aa1/AA+	17	23	29	36	46	58	78
Aa2/AA	24	31	38	46	55	66	86
Aa3/AA-	31	40	47	56	64	74	95
A1/A+	38	49	57	66	74	81	103
A2/A	45	58	66	76	83	89	111
A3/A-	45	61	70	81	88	96	120
Baa1/BBB+	65	83	94	107	115	125	153
Baa2/BBB	71	90	100	114	123	132	161
Baa3/BBB-	93	125	144	167	183	199	250
Ba1/BB+	203	217	231	247	259	272	287
Ba2/BB	233	248	264	281	294	308	324
Ba3/BB-	263	279	296	314	328	344	361
B1/B+	298	315	333	352	368	385	403
B2/B	328	346	365	386	403	421	440
B3/B-	357	377	397	419	437	456	477
Caa/CCC+	392	413	434	457	476	497	519
US Treasury Yield	0.25	0.67	1.10	1.68	2.01	2.22	2.82

Spread values represent basis points (bps) over a US Treasury security of the same maturity, or the closest matching maturity.

Methodology:
Reuters Pricing Service (RPS) has eight experienced evaluators responsible for pricing approximately 20,000 investment grade corporate bonds. Corporate bonds are segregated into four industry sectors; industrial, financial, transports and utilities. RPS prices corporate bonds at a spread above an underlying treasury issue. The evaluators obtain the spreads from brokers and traders at various firms. A generic spread for each sector is created using input from street contacts and the evaluator's expertise. A matrix is then developed based on sector, rating, and maturity.

US Treasury Yields for this date are available in the BondsOnline Chart Center

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COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MATTHEW T. HANSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Q. Please state your name and business address.

A. My name is Matthew T. Hanson and my business address is 290 W. Nationwide Boulevard, Columbus, OH 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"). I assumed my current position as Director of Financial Planning in September 2012.

Q. What are your responsibilities as Director of Financial Planning?

A. I am responsible for the financial planning and budgeting process for the NiSource Inc. ("NiSource") gas distribution business segment ("NGD"), which includes Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

Q. What is your educational and professional background?

A. I received a Bachelor of Science in Business Administration degree, majoring in Accounting, in 1998 from The University of Dayton. My career began at Ernst & Young LLP in 1998 as a member of the Audit/Advisory function. In 2001, I took a role at Cardinal Health where I was employed in roles of increasing responsibility until 2011 culminating as the Director of Finance. In 2011, I left Cardinal Health to take a position as the Vice President of Financial Planning and Analysis at inVentiv Communications where I remained until I came to NiSource in my current capacity.

Q. Have you ever testified before a regulatory Commission?

A. Yes. I provided testimony in Columbia's 2014 base rate case at Docket No. R-2014-2406274.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports Columbia's projected Operations and Maintenance ("O&M") expenses for the Fully Forecasted Rate Year (through December 31, 2016), that have been incorporated in Columbia witness Miller's cost of service analysis.

Q. What is the basis for the forecasted O&M expense included in the Fully Forecasted Rate Year?

A. The forecasted O&M expense included in the Fully Forecasted Rate Year test period is derived from the Company's most recent O&M budget.

Q. How is Columbia's O&M budget developed?

A. The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approach. The O&M expense budget serves as a key component of the overall Columbia budget and as a cost management tool for both NGD and Columbia management.

Q. Please explain.

A. The NGD management team, including Columbia's management team, first identifies general O&M requirements and planning objectives in conjunction with NiSource Inc.'s senior management. These requirements and objectives are then communicated to each successive layer of management and employees, as well as the NGD Financial Planning team, which is responsible for the development of all NGD budgets. It is the responsibility of these groups, working together, to ensure: (1) that Columbia's budgets, including O&M expenses, are developed in accordance

with overall financial goals and objectives; and (2), that individual company operational and administrative requirements are addressed.

Q. How is the O&M budget developed?

A. The O&M budget for Columbia is based on a grass roots concept in which individuals responsible for approving expenditures are also responsible for budgeting the expenditures. The process generally follows organizational responsibility. Department heads are responsible for overseeing the development of O&M budgets for all cost centers under their control. Budgets originate in operating center locations in the field and other departments representing Columbia's major business functions; these budgets are combined with a corporate-level budget to arrive at a total company budget. I will discuss the corporate-level budget later in my testimony.

Annually, the Company's O&M budget is developed by department by cost element with the assistance of the NGD Financial Planning department. Each department's budget is reviewed with and approved by the NGD CFO and CEO. This review includes a comparison of a series of data points based on most recent experience. Specifically, the proposed O&M budget is compared to the most recent year's O&M budget as well as compared to the prior year's actual, experienced amounts. These comparisons help identify trends and allow for measurement against management's expectations. Once finalized, the departmental O&M expense budget is incorporated into the business unit's operating plan.

Q. Does that conclude the development of the O&M expense budgeting process?

A. No. Upon agreement and sign-off on the departmental O&M expense budget, the current year O&M budget is then developed in more detail (i.e., at the individual cost center level) beginning in the preceding fourth quarter for the current year. The process concludes in January.

The current year detailed O&M budget is reviewed against actual results each month throughout the year to determine the reasons for variances and to take appropriate action. If known variances are the result of timing that will be resolved within the year, then those variances are monitored closely but no further action is taken unless it is deemed at some point during the year that the variance will result in a true budget variance at the end of the year. When the review of monthly budget versus actual reveals variances that are expected to last throughout the year, the Financial Planning department and NGD CFO will work with Columbia management to determine the drivers of the variances and steps to be taken to reduce the variance to the overall budget. In the case of an unexpected underspend, funds will be re-allocated to other departments within Columbia to complete projects or work that may have been scheduled for future periods or work that was on hold pending available funds. If the variance is expected to result in an overspend, costs will be managed tightly within the department and Columbia as a whole to mitigate the budget variance identified.

Q. Does the O&M expense budgeting methodology described in your testimony result in an accurate estimate of expenses to be incurred during the fully forecasted rate year?

A. Yes. Columbia has experienced a variance of less than 3% to the original O&M budget in four of the last six years with the only exceptions being 2011 and 2014 when the variance was approximately 6.5% and 4.5% respectively. Specifically, in 2011 Columbia experienced larger than budgeted pension contributions. When that factor is normalized, the remaining budget variance for the year was well below 1%. In 2014, the variance to the budget was driven by a few key factors. One factor was that $1.3M of productivity savings was budgeted to help Columbia achieve the overall budget objective established by management but this savings was not realized. In addition, NCSC Shared Services costs were higher than expected; primarily as a result of IT spend, as significant projects were ramped up. Incentive compensation also drove this variance, as the payout was higher than anticipated due to positive business results. Notably, in each of the last 6 years Columbia has actually overspent the original O&M budget in the ranges noted, which supports the fact that the O&M budget is a conservative approach for ratemaking purposes. Please refer to Exhibit MTH-1 accompanying this testimony for a comparison of actual results versus the annual original O&M budget for the years 2009 through 2014. Overall, this Exhibit indicates a high level of O&M budgeting accuracy by

Columbia and, accordingly, provides a high level of confidence as to the accuracy of the O&M expenses included in the fully forecasted rate year.

Q. Have you excluded certain cost categories from your comparison?

A. Yes. O&M expenses that are designed to match, or track against, revenues related to specific programs or costs such as gas costs and low-income programs have been excluded. Such revenue matching mechanisms have been previously approved by this Commission, and ensure that there is no impact on net operating income. The accounting treatment generally allows such expenses to be deferred as incurred and reclassified to expense when the recovery of program costs is recorded in revenue. While these O&M expense variances may be material, there is a corresponding offsetting revenue variance. For that reason, I have excluded these expenses from the comparison so as not to distort the accuracy of the budget.

Q. What is meant by the term corporate-level budget?

A. Earlier in my testimony I explained that Columbia's budget for field operating centers and other major business functions is combined with a corporate-level budget to arrive at a total company budget. The corporate-level budget represents categories that are budgeted at a total Columbia or a NiSource-level, and not an individual Columbia department level. This allows for each corporate-level department to focus exclusively on the expenditures for which they are directly responsible. Examples of O&M expenses included at the corporate-level are

employee benefits, benefits administration fees, audit fees, in-house legal, human resources, corporate insurance, regulatory amortizations, and revenue trackers.

Q. What are the principal assumptions used in the development of the labor cost element for specific department budgets included in the forecasted test period O&M expenses?

A. Labor expense is based on projected headcount and wage increase assumptions. More detailed labor budgets are developed by projecting the year's labor based on a trend analysis. The projection includes estimates for headcount, gross salary, overtime, vacation and sick time, and labor charges in from other departments. This results in a sub-total for total labor dollars available by month, and this pool is then split between O&M accounts, capital, and charges to other departments. The second step of the process involves developing an estimate for the following year's O&M labor budget based on the projected work by activity, and this estimate will be used to determine how much of the labor budget should be allocated to O&M accounts. The remaining labor resources are then allocated to capital or charged out to other departments where work may be performed. A final reasonableness check is done to compare the budgeted amount for capital labor against prior year actual charges to ensure the numbers are in line with the most recent results.

Q. Does your budgeting analysis include any projections regarding Columbia headcount?

Yes, Columbia is projecting 616 and 633 active full-time employees for 2015 and 2016 respectively, and an overall wage increase guideline of 3% for exempt employees. The headcount is increasing above the ending Historic Test Year level of 580 active full-time employees. These increases are driven primarily by increases in Field Operations and System Operations to support safety initiatives and ongoing compliance work. This includes adding damage prevention coordinators, leak inspectors and front line leaders in the field. Increases in headcount are also expected in Engineering and Construction.

Q. Can you provide examples of such non-labor activities or events that have been taken into account in the development of the O&M expense budget?

A. Yes. Non-labor expenses start with the assumption that amounts are to be held relatively flat year to year reflecting a normal, ongoing level of expenses and further adjusted for activities or events that are reasonably expected to occur.

Expenses related to enhanced Operator Qualification ("OQ") training beginning in January 2015 have been added to the budget. The estimated impact of this training has been taken into account in the increased labor expected to be incurred as well as in the travel and facilities needed to support the training. The non-labor costs appear primarily in the travel that hits employee expenses and in the increased rent and leases for the new facilities. Columbia has also budgeted for facilities costs related to new facilities and lease expenses as we move to more functional locations beginning in 2014 and ramping up in 2015 and 2016. Increased damage prevention

spend is also included in 2015 and 2016 for new GPS technology used for line locating. Safety spend increases are included in the future test year and the fully forecasted rate year outside services budget category at a full year's spend level, because these increased activities were not at a full year operating level during the Historic Test Year.

Q. Is Columbia provided with any assumptions when preparing forecasted O&M budgets?

A. Yes, corporate assumptions are provided to Columbia and other NiSource companies for purposes of establishing O&M budgets. Corporate assumptions provided to Columbia include several major categories. Employee benefits expenses are based on information provided by NiSource's independent actuary, AON Hewitt. For instance, the pension costs projected in the budget for the rate year are part of the actuarial estimates provided by AON Hewitt. Corporate insurance expenses are based on estimated property and casualty premium costs developed by NiSource's Corporate Insurance Department. Audit fees are based on estimates developed by NiSource Accounting. Telecommunications expenses are based on estimates developed by NiSource Information Technology. NCSC Shared Service expenses are based on estimates of services to be performed by NCSC, NiSource's shared services company, for Columbia, and are included in the NCSC Shared Services budget. This year, that budget has been broken down into two cost elements, NCSC- Shared Services and NCSC- Shared NGD Operations. Please refer

to pages 18-19 of Columbia witness Miller's testimony for an explanation of the distinction between these cost elements. Benefits administration fees and incentive plan expenses are based on estimates developed by NiSource Human Resources. Expenses related to the implementation of a single general ledger and chart of accounts for all NiSource companies are based on estimates developed by the NiSource Financial Transformation (NiFIT) group.

Q. How are the budgets developed for the corporate-level O&M budgets?

A. NCSC Shared Services budgets, such as the legal and human resources budgets, are based on the individual budgets developed by each NCSC department. Similar to Columbia's O&M budgeting methodology, NCSC budgets its O&M expenses by cost categories such as labor, materials, outside services and other expenses. In addition, each department is allocated a portion of NCSC's indirect costs, such as benefits, taxes, depreciation and other expenses to arrive at a fully loaded cost. The fully loaded corporate-level budget is allocated to Columbia and other NiSource companies through the NCSC Shared Services budget using an allocation basis or bases as determined by each department.

Q. What allocation bases are available to each department for allocating their budgets to NiSource companies?

A. The direct costs from NCSC departments, as mentioned above, such as labor, materials, outside services and other expenses are allocated based on methods as

deemed appropriate by department management. Please refer to Exhibit 4, Schedule 11, Attachment H.

Q. What is the O&M expense level for the historic test year and fully forecasted rate year?

A. O&M expense before ratemaking adjustments is $126,964,667 for the historic test year ended November 30, 2014 and $142,589,000 for the fully forecasted rate year ending December 31, 2016, an increase of $15,726,683 before pro forma ratemaking adjustments.[1]

Q. Please explain the key variances in O&M expense levels between the historic test year and the budgeted amounts for the future test year.

A. Please refer to Exhibit 104 Schedule 1 Page 3 for a breakdown of the O&M expense variances from the historic test year to the budgeted future test year ended November 30, 2015. The methodology for how Labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104 Schedule 10 Page 1 for an illustration of the $1.4M increase in labor from the normalized historic test year to the budgeted future test year.

Incentive compensation decreases from the historic test year to the future test year, despite the increase in labor, due to the fact that actual financial and key metric results in the historic test year resulted in an expected incentive compensation payout above the targeted level. The budget for all future years is always calculated

[1] This testimony compares O&M expenses independent of expense items specifically tracked against revenues as discussed earlier in this Statement.

at the target level which creates the year over year decrease from the historic test year to the future test year.

As mentioned previously, the budgeted amount for benefit expenses such as pension, OPEB and other benefits are based on actuarial estimates provided by NiSource's independent actuary AON Hewitt. The largest driver of change in benefits from the historic test year amount to the future test year budget is the timing of pension funding, which has resulted in a funding event not occurring within the 12 month future test year window.

The decrease in Outside Services from the historic test year to the future test year is illustrated at Exhibit 104 Schedule 11 Page 1.

The reason for the increase in rent and lease expense was referenced in my prior testimony. Please see Exhibit 104 Schedule 12 Page 1 for a breakdown of the increase in rents and leases by location.

Increases in Employee Expenses are driven by travel increases that will result from the increase in training that is planned to occur during the future test year.

The increase in Materials and Supplies expense results from historical trend in spending forecasted out for the future test year, as explained previously.

The increases in NCSC Shared Services and NCSC Shared NGD Operations are explained in detail at Exhibit 104 Schedule 13 Page 1 and Exhibit 104 Schedule 14 Page 1 respectively.

Q. Please explain the key variances in O&M expense levels between the future test year and the budgeted fully forecasted rate year.

A. Please refer to Exhibit 104 Schedule 1 Page 4 for a breakdown of the O&M expense variances from the future test year to the budgeted fully forecasted rate year. The methodology for how Labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104 Schedule 10 Page 2 for an illustration of the $1.7M increase in labor from the normalized future test year to the budgeted fully forecasted rate year.

Incentive compensation increases from the future test year to the fully forecasted rate year commensurate with the increase in labor costs.

As mentioned previously, the budgeted amount for benefit expenses such as pension, OPEB and other benefits are based on actuarial estimates provided by NiSource's independent actuary AON Hewitt.

The increase in Outside Services from the future test year to the fully forecasted rate year is illustrated at Exhibit 104 Schedule 11 Page 2.

The reason for the increase in rent and lease expense was referenced in my prior testimony. Please see Exhibit 104 Schedule 12 Page 2 for a breakdown of the increase in rents and leases by location.

Increases in Fleet are driven by expected headcount and fuel cost increases. The headcount increases have been discussed in my earlier testimony and fuel is not expected to remain at the current cost level. The increases in NCSC Shared Services

and NCSC Shared NGD Operations are explained in detail at Exhibit 104 Schedule 13 Page 2 and Exhibit 104 Schedule 14 Page 2 respectively.

Q. Does this complete your direct testimony?

A. Yes it does.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense 0&12 vs. Actual

	0&12						Actuals						Variance					
CE	2009	2010	2011	2012	2013	2014	2009	2010	2011	2012	2013	2014	2009	2010	2011	2012	2013	2014
Labor	23,873	23,108	22,910	23,693	25,709	25,251	23,153	23,577	22,845	23,996	25,124	25,818	(720)	469	(65)	303	(585)	567
Incentive Compensation	293	1,171	1,149	1,249	1,238	1,333	1,303	1,628	1,649	1,690	1,845	1,816	1,010	457	500	441	607	484
Pension	2,119	6,005	6,598	-	3	1,137	392	5,799	13,088	91	2,489	1,131	(1,727)	(206)	6,490	91	2,486	(6)
OPEB	715	1,065	492	(154)	(284)	(550)	1,683	775	(213)	88	(454)	(1,298)	968	(290)	(705)	242	(170)	(748)
Other Employee Benefits	5,076	6,363	6,509	6,184	6,454	4,584	4,995	7,472	6,210	5,880	5,635	5,432	(81)	1,109	(299)	(304)	(819)	848
Outside Services	15,636	15,175	13,094	12,123	12,104	22,311	15,180	15,440	13,244	12,133	14,113	22,070	(456)	265	150	10	2,009	(241)
Rent and Leases	1,314	1,374	1,458	1,615	1,887	2,273	1,306	1,207	1,348	1,485	1,699	1,699	(8)	(167)	(110)	(130)	(188)	(574)
Corporate Insurance	3,116	3,574	3,413	3,048	3,004	3,087	3,045	3,241	2,926	2,763	2,734	2,796	(71)	(333)	(487)	(285)	(270)	(291)
Injuries and Damages	1,209	944	795	630	630	500	605	545	340	241	305	(185)	(604)	(399)	(455)	(389)	(325)	(685)
Employee Expenses	1,109	1,046	1,163	1,142	1,295	1,305	1,405	1,450	1,553	1,465	1,376	1,264	296	404	390	323	81	(41)
Company Memberships	347	345	249	292	262	256	295	250	293	262	249	313	(52)	(95)	44	(30)	(13)	57
Utilities and Fuel Used in Company Operations	675	570	567	503	1,167	1,303	451	417	487	1,094	1,247	1,244	(224)	(153)	(80)	591	80	(59)
Advertising	500	185	170	170	470	170	389	281	167	133	243	236	(111)	96	(3)	(37)	(227)	66
Fleet	4,663	4,104	4,421	5,046	5,452	5,708	4,650	4,726	5,092	5,357	5,780	6,106	(13)	622	671	311	328	398
Materials & Supplies	4,929	4,767	4,775	4,899	4,649	5,024	4,741	4,967	4,412	4,353	5,171	5,343	(188)	200	(363)	(546)	522	319
Other O&M	(3,987)	(3,780)	(116)	(783)	60	(1,906)	(3,527)	(3,005)	157	(63)	31	512	460	774	272	720	(29)	2,418
PUC, OCA, OSBA Fees	1,673	1,953	1,354	1,454	1,699	1,583	1,721	1,539	1,348	1,523	1,585	1,815	48	(413)	(5)	69	(114)	232
NCSC Shared Services & NGD Shared Operations	31,889	38,399	37,740	39,742	44,597	47,962	34,023	36,457	38,899	40,164	43,374	50,760	2,134	(1,942)	1,159	422	(1,223)	2,798
Amortization	82	75	(243)	(1,446)	(1,455)	185	82	0	(489)	(1,446)	(594)	185	(0)	(74)	(246)	(0)	861	-
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense Before	95,231	106,443	106,498	99,407	108,941	121,516	95,892	106,766	113,356	101,209	111,952	127,057	661	324	6,858	1,802	3,011	5,542

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
PANPILAS W. FISCHER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Q. Please state your name and business address.

A. My name is Panpilas W. Fischer. My business address is 290 W. Nationwide Blvd, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Manager of Income Taxes at NCSC.

Q. Please briefly describe your professional experience.

A. I began my career with KPMG as a staff auditor in 1987. I then joined the firm of Clark, Schaefer, Hackett and Co., CPAs as a Senior Auditor in 1989 where I performed financial audits, reviews and compilations, and prepared and reviewed tax returns for corporations, partnerships and individuals. In October 2000, I started working as a tax analyst for NCSC and in October 2003 I was promoted to my current position.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration in Accounting in 1987 from The Ohio State University. I am a Certified Public Accountant and member of the Ohio Society of Certified Public Accountants.

Q. What are your responsibilities in your current position?

A. In my current position with NCSC, my principal responsibilities include supervision and preparation of all of Columbia Gas of Pennsylvania's ("Columbia" or "the Company") income tax activities including the booking of income tax accruals and deferred tax entries, the filing of income tax returns, tax research and

planning and the preparation of income tax data and related testimony for rate proceedings.

Q. Have you previously testified before this or any other regulatory agency?

A. I have previously provided testimony to the Pennsylvania Public Utility Commission ("Commission"), the Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Public Service Commission of Maryland and the Commonwealth of Virginia State Corporation Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to present and support Columbia's income tax and other tax expense included in the cost of service. The filing includes federal and state income tax recovery, reduction of rate base for deferred income taxes, as well as a reduction to tax expense resulting from the Company's 2008 change in tax method of accounting for repairs. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve month period ending November 30 2014) and Exhibit 107 for the Fully Forecasted Rate Year (the twelve-month period ending December 31, 2016). Taxes other than income tax are included in Exhibit 6 and Exhibit 106.

Q. Will you explain the basis for the income tax calculations for the Historic Test Year?

A. The tax calculations were made in accordance with federal and state laws. The federal tax rate is 35% and the Pennsylvania tax rate is 9.99%. The Historic Test Year tax calculations have been impacted by certain items that have been historically treated as flow-through or deferred in rate making proceedings.

Q. Can you explain the flow-through items included in the tax provision?

A. Prior to 1981, federal tax statutes did not require full normalization of accelerated tax depreciation versus book straight line depreciation recovered in rates. Beginning in 1981 for Columbia, normalization, under the Internal Revenue Code, does not permit the flow-through or refund of accelerated depreciation benefits by a utility to its customers. Such benefits must be provided for in a deferred tax reserve, and that reserve may be allowed as a rate base reduction. Prior to 1984, the Company flowed-through the benefits of accelerated depreciation for vintage years prior to 1981. Beginning in 1984, the Company began to normalize the remaining book versus tax differences on Asset Depreciation Range vintages (1971 through 1980) based upon the Commission's order in Docket No. R-832493. For the Historic Test Year, we are in a position where the Company has very little in terms of tax depreciation remaining on pre-1981 assets. Thus, we are in a turnaround position, since book depreciation is now higher than tax depreciation.

In addition, the Company has excess deferred taxes that were originally computed at a 46% federal tax rate for 1981-1987 vintages that are being refunded in rates under the Average Rate Assumption Method ("ARAM"). This method required the Company to keep deferred taxes intact until book depreciation exceeds tax depreciation for those vintage years, and to flow back the deferred tax excess between the 46% rate and the current 35%. Since most of the property was 15 year property for federal purposes, the excess is in a turnaround situation. The company projects to record lower tax expense by $88,396 in its federal tax provision related to the excess deferred taxes for the Fully Forecasted Rate Year.

Q. How is Columbia handling the reduction in tax caused by the 2008 change in method of accounting for repairs?

A. As agreed in the settlement of Columbia's 2010 rate case (Docket No. R-2009-2149262), a refund of the $37,487,634 is being made to customers, which reflects the cash benefit received in 2009 for the tax year 2008 method change. As of December 31, 2014, a total of $35,442,920 was amortized as agreed in the settlement of Columbia's 2012 rate case (Docket No. R-2012-2321748) and an additional $2,044,714 is being amortized through the period ended December 31, 2016 as agreed in the settlement of Columbia's 2014 rate case (Docket No. R-2014-2406274) which leaves a remaining unamortized balance at December 31, 2015 of $681,571. This case reflects the remaining $681,571 as of December 31, 2015 being amortized over 12 months of the Fully Forecasted Rate Year which represents a full amortization of the refund by the end of the Fully Forecasted Rate Year. As provided in the 2010 Rate Case settlement, the amortization is without interest and without a deduction of the unamortized balance from rate base.

Q. How does the change in method impact Columbia's taxable income going forward?

A. For a period of time, the repairs deduction is anticipated to exceed deductions if the plant had been capitalized for tax purposes, and thus will continue to result in a reduction to taxable income. However, beginning post October 18, 2011 (the effective date of Columbia's 2010 rate case) the repairs deduction is being normalized under deferred tax accounting, so there will be no impact on total federal tax expense.

Q. Are there any other items treated as flow-through in the rate-making process?

A. Yes. The Company continues to reduce its income tax allowance for the net cost of retirements, which is allowed as a deduction on its tax return. In addition, there are three permanent differences included in the tax provision. Permanent differences are items of income or expense that will never be included in the federal tax return. Items increasing tax expense as a result of being non-deductible include expenses for a portion of business meals, employee stock purchase plan compensation and a portion of lease expense on vehicles.

Q. How has the Company handled Pennsylvania Corporate Net Income Taxes in its calculation of deferred income taxes for depreciation?

A. The Company, based on prior Commission orders, has not normalized deferred state income taxes. The Company continues to flow-through the state income tax benefits of accelerated depreciation on its book depreciable assets.

Q. Did the Company receive a refund from Pennsylvania for the change in method?

A. No. The Company had a $149.2 million net operating loss for 2008 that it carried forward into 2009 and will carry forward into future years. The Company reduced its Pennsylvania taxable income by 15% of taxable income in 2009. The Company also had a $4.1 million net operating loss for 2010 and a $69.7 million net operating loss for 2011 that is being carried forward. The reduction is the higher of $3,000,000 or 20% of taxable income in 2010, 2011, 2012 and 2013. The reduction increases to the higher of $4,000,000 or 25% of taxable income in 2014 and the reduction increases again to the higher of $5,000,000 or 30% of taxable income in 2015 and thereafter. The Company's claimed tax expense takes such benefit into account.

Q. Was a Consolidated Tax Adjustment included in the claim in this case?

A. Similar to the Company's 2014 base rate case, a Consolidated Tax Adjustment was not included in this case because Columbia Gas of Pennsylvania was a loss company on average for the three year period 2011-2013. The loss is the result of 50-100% bonus depreciation allowed under federal tax law (the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 and the American Taxpayer Relief Act of 2012) for most assets placed in service during the Historic Test Year. Under these circumstances, it is appropriate not to apply a consolidated income tax adjustment in this case. Nevertheless, I have provided details of the income and losses of affiliated companies for the three year period in Exhibit No. 7, pages 2 through 4.

Q. Are there other reasons why a consolidated tax adjustment is not appropriate?

A. Yes, most of the "tax loss" generated by the NiSource system is the result of tax deductions generated by debt issued to finance the acquisition of Columbia Energy Group. As shown on Exhibit No. 7, pages 3 and 4, over $189 million of the $266 million of average annual losses for unregulated companies arise from this debt, which is recorded as a loss for NiSource Inc. The cost of this debt is not reflected in Columbia's rates and the debt does not finance rate base. Since the debt cost associated with those incremental investments outside of the rate base is not reflected in Columbia's rates to customers, it is not appropriate to provide the tax deductions associated with such cost to ratepayers.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, page 19 of Exhibit 7 delineates total pro forma tax expense of $43,539,280. This total includes $4,359,333 of state income taxes, which is based on $139,561,820 of operating income less $26,145,886 of interest expense on debt for total pre-tax income of $113,415,934, resulting in an effective state income tax rate of 3.84%. This reduced expense, as compared to the Pennsylvania statutory rate of 9.99%, is a result of the flow through treatment of accelerated depreciation deductions for state income tax purposes. The expense for federal income taxes is $39,179,947, or 34.55%, of the pre-tax income less state income taxes. This 34.55% expense is .45% less than the federal statutory rate of 35%. The difference is largely attributable to the tax repairs refund amortization being flowed through in rates.

Q. Please continue with respect to the Fully Forecasted Future Rate Year.

A. For the proposed income tax recovery, the amounts can be found on Exhibit 107 pages 16 and 17. The same individual items creating a variance from statutory rates in the historical data create a variance in proposed rates. Minor adjustments have been made to reflect forecasted numbers during the fully forecasted test year.

Q. How have taxes impacted the Company's rate base?

A. Exhibit 107, page 5, delineates the reduction in rate base for deferred income taxes. The amounts include deferred taxes on net utility plant that have or will be normalized by the end of the Fully Forecasted Rate Year, as well as deferred taxes on inventory, customer advances and building leases.

Q. How has the deduction for 263A mixed service costs impacted deferred taxes in rate base?

A. As agreed in the settlement of Columbia's 2012 rate case (R-2012-2321748), the Company has been given permission to normalize this deduction for federal income taxes and treat the deferred taxes as a reduction to rate base. The adjustment can be found on Exhibit 107, page 9, line 19.

Q. Is there an inclusion of deferred taxes for the Federal Net Operating Loss in rate base?

A. In the Historic Test Year the deferred tax asset for the Federal Net Operating loss, which represents the remaining balance of un-utilized net operating loss, is $15,471,269 as shown in Exhibit 7, page 9. The Company has experienced net taxable losses for the years 2010, 2011, 2012 and 2013 as a result of taking deductions for 50-100% bonus depreciation, resulting in the deferred tax asset being recorded for the un-utilized net operating losses. 50% bonus depreciation deductions were taken in 2010, 2012 and 2013 and 100% bonus depreciation deductions were taken in 2011 as permitted under tax laws in effect per my testimony on page 6. In 2014 the Tax Increase Prevention Act of 2014 extended 50% bonus depreciation to assets placed in service in 2014 thereby extending the time when the net operating loss will be utilized. The deferred tax asset represents the cash benefits the Company has not received because of the net operating losses. The deferred tax asset is included in rate base because the Company cannot reflect an increase in deferred taxes for tax depreciation deductions that have not been realized. To do so would violate the principles of the Normalization requirements under the Internal Revenue Code. Past IRS rulings addressing this issue have made it clear that companies cannot reduce rate base for benefits that have not been

realized. The deferred tax asset for the un-utilized net operating losses will decline after 2014 as there is currently no bonus depreciation legislation enacted for assets placed in service beyond 2014. Due to the net operating losses generated by bonus depreciation deductions in the aforementioned years, the expectation is that the Company will not utilize all of its net operating losses until the end of 2017. Therefore, there is an increase to rate base on Exhibit 107, Page 5 of $2,590,812 as a deferred tax asset for the amount of unutilized net operating loss for the Fully Forecasted Test Year.

Q. Please explain the adjustment to deferred taxes for the Fully Forecasted Test Year on Exhibit 107, Page 5.

A. Whenever there are estimated changes in the deferred taxes that occur in a future rate period, the Normalization requirements of the Internal Revenue Code require that the deferred taxes be reflected on a pro rata basis as provided under Reg. Section 1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test period after the effective date of the rate order. Under the pro rata basis, the change in the deferred taxes is determined by multiplying the change by a fraction of the number of days remaining in the period at the time such change is to be accrued over the total number of days in the future period. Applying this calculation resulted in a decrease to deferred taxes of $11,284,120.

Q. Are you sponsoring any other expense adjustments?

A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act ("FICA") Tax, Property Tax, Capital Stock Tax and License and Franchise Tax. These adjustments are delineated on Exhibits 6 and 106.

Q. Please explain the FICA adjustment.

A. The adjustment represents an increase in FICA taxes as they apply to the payroll adjustments discussed in Company witness Miller's testimony (Columbia Statement No. 4). An increase in payroll taxes of $62,713 is reflected in the annualized Historic Test Year. Please see Exhibit No. 6, Schedule 2, Page 3 of 5 for the calculation. For the Fully Forecasted Rate Year, the Company is projecting a higher payroll base, thus increasing payroll taxes by $159,123. Please see Exhibit No. 106, Schedule 2, Page 3 of 5 for the calculation.

Q. Please explain the property tax adjustment.

A. The PURTA tax and the locally assessed property tax on Pennsylvania property are both consistent with the most recent year end tax levels as of December 31, 2013. The West Virginia tax for gas stored underground was developed using the December 31, 2013 assessed value and the 2013 tax rate. This annualized level of $547,250 is higher than the Historic Test Year level of $546,121, as shown on Exhibit 6, Schedule 2, Page 4 of 5, resulting in an upward adjustment of $1,129. The detail supporting this calculation for the Fully Forecasted Rate Year is provided on Exhibit 106, Schedule 2, Page 4 of 5. The pro forma Fully Forecasted Rate Year reflects an upward adjustment of $2,957 from the annualized level as a result of using the December 31, 2014 assessed value and the 2013 tax rate which is the latest available at this time.

Q. Please explain the Capital Stock tax adjustment.

A. Similar to the property tax adjustment, the capital stock tax adjustment begins with the last known basis as of December 31, 2013. To this, the 2014 rate was

applied, resulting in a $88,326 downward adjustment from the Historic Test Year level. The major reason for the adjustment downward is the rate decrease due to the phase out of the Pennsylvania capital stock tax. The capital stock tax for the pro-forma Fully Forecasted Rate Year ending December 31, 2016 is $0 using a rate of .000 because under current legislation the capital stock tax is completely phased out by the end of 2016. This represents a downward adjustment of $269,204 from the annualized level of $269,204.

Q. Please explain the License and Franchise Tax adjustment.

A. The License and Franchise tax annualized level of $279 is the same as the Historic Test Year level. This amount reflects the latest West Virginia franchise tax liability for the Company. The pro forma Fully Forecasted Rate Year was not adjusted from this level.

Q. Please explain the Other Tax adjustment on Exhibit 106, Schedule 2, Page 2.

A. Other taxes are primarily comprised of excise tax. The annualized level of $6,899 was not adjusted for the Historic Test Year. The pro forma Fully Forecasted Rate Year was also not adjusted from this level.

Q. Does this conclude your testimony?

A. Yes.

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MARK BALMERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

TABLE OF CONTENTS

INTRODUCTION 1

I. PRINCIPLES OF REVENUE ALLOCATION AND RATE DESIGN 3

II. REVENUE ALLOCATION 4

III. RATE DESIGN 10

IV. BILL COMPARISONS 23

Introduction

Q. Please state your name and business address.

A. Mark Balmert, my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am Director of Regulatory Strategy & Support for NiSource Corporate Services Company ("NCSC"). NCSC provides, among other services, accounting and regulatory-related services for the subsidiaries of NiSource Inc. ("NiSource"). I am testifying on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), which is one of the NiSource local distribution companies.

Q. What are your responsibilities?

A. My section within NCSC is responsible for the preparation and support of special regulatory studies, such as allocated cost of service ("ACOS") studies, lead lag studies, revenue development, and rate design in support of rate proceedings for the six NiSource Gas Distribution Companies, which consist of Columbia Gas of Maryland, Columbia Gas of Kentucky, Bay State Gas Company (d/b/a Columbia Gas of Massachusetts), Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia. I am also responsible for the development of regulatory accounting requirements for Columbia Gas of Ohio with duties including revenue requirement development, cost of gas filings, infrastructure replacement and other recovery mechanisms filings. In addition, I am responsible for the information technology requirements for the NCSC regulatory department.

Q. What is your educational and professional background?

A. I graduated from The Ohio State University in June of 1979, earning a Bachelor of Science Degree in Business Administration with a major in accounting. I have been employed by various entities within the Columbia Energy Group and its successor, NiSource, in capacities related to rates, regulatory accounting and compliance, and information technology applications since October 1979. In February of 2012, I was named Directory of Regulatory Strategy & Support for NCSC, which is the position I currently hold.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before this Commission as well as the Public Utilities Commission of Ohio, the Virginia State Corporation Commission, the New Hampshire Public Utilities Commission, the Kentucky Public Service Commission, the Public Service Commission of Maryland and the Massachusetts Department of Public Utilities.

Q. What is the purpose of your testimony in this proceeding?

A. I will sponsor and describe Exhibit 103, Schedule 8, Columbia's proposed rate design. I will address the appropriate revenue allocation among the various rate classes, discuss proposed customer charges, and discuss proposed rate design changes that include both Columbia's proposed splitting of Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), Small General Distribution Service ("SGDS") and Small Distribution Service ("SDS") volumetric charges and the merging of Large General Sales Service ("LGSS") volumetric

charges with the Small Distribution Service ("SDS")and Large Distribution Service ("LDS")rate classes. I will also sponsor and describe Exhibit 111, Schedules 5 and 6, Columbia's comparison of current and proposed rates.

Q. How is your testimony organized?

A. Section I, Principals of Revenue Allocation and Rate Design; Section II, Basis of splitting SGSS, SCD, SGDS, and SDS volumetric charges; Section III, merging of LGSS volumetric charges with the SDS and LDS rate classes; Section IV, Revenue Allocation among the rate classes; Section V, Rate Design; and Section VI, Bill Comparison.

I. PRINCIPLES OF REVENUE ALLOCATION AND RATE DESIGN

Q. Please describe the rate design principles that the Company considered when developing the proposed rates.

A. The principles that were used to guide the development of the Company's rate design include: efficiency, simplicity, continuity, fairness, and earnings stability. An efficient rate design provides accurate price signals and, thus, an accurate basis for consumers' decisions and provides the Company a reasonable opportunity to recover the cost of providing service. A simple rate structure is one that is understood by customers. The goal of rate continuity seeks gradual changes to rate design that will allow customers to adjust their consumption patterns, as needed. A fair rate design will consider the results of the allocated cost of service study in determining customer classes' total revenue responsibility. Finally, earnings

stability means that the Company's earnings resulting from its rates should not vary significantly over the period of a few years.

II. REVENUE ALLOCATION

Q. Please state the basis for the Company's proposed revenue allocation among the rate classes.

A. Consistent with the goal of continuity, Columbia seeks to gradually move base rates closer to the allocated cost of service for each customer class. The cost to serve each rate class is defined through the allocated cost of service study.

Q. How were the results of the cost allocation studies used in designing the proposed revenue requirements and rates?

A. The Allocated Cost of Service Studies ("ACOS Studies") were used as a guide for assigning additional revenue responsibility to customer groups. The Peak & Average Study and the Customer Demand Study performed by Company witness Elliott (Columbia Statement No. 7) provides information about class cost relationships and helps establish a "zone of reasonableness" from which an appropriate revenue allocation and rate design can be derived. The Average Study was used to establish a point of reasonableness of class rates of return at present and proposed rates. The results of the cost allocation studies support the Company's proposed rate schedules. Details concerning the application of the cost study results in the proposed rate design are provided later in this testimony.

Q. Has there been any change in the designation of classes for the ACOS Studies?

A. Yes. As described by Columbia Witness Elliott, the Company no longer reflects the LGS rate as a separate customer class. Smaller LGS customers are eligible to be served under the SDS rate schedule. Logically, the cost to serve these customers does not vary. Therefore, the SDS and small LGS customers are combined in a single class. Similarly, the large LGS customers are eligible for service under Rate LDS. Thus, these customers have been combined in a single class. This combination also has consequences for rate design, which I discuss later in my testimony.

Q. What are the results of the ACOS studies?

A. Exhibit MPB-1, attached to my testimony, shows the class-level returns and return indices for each of the ACOS studies at present rates. Return indices compare individual class returns to the overall total company return. A return index is calculated by dividing the class return by the total company return, then multiplying the result by 100 to produce the index. The total company return index will always be 100. The closer individual classes return is to the total company return, the closer its index will be to 100 and to parity. The term "parity" in this context means that the class return and the total company return are equal.

It should be noted that factors such as class size, customer diversity, and economic conditions will result in returns and indices that are more volatile for some classes than for others. For example, because of the large numbers of customers in the residential and SGSS/SCD/SGDS classes, the returns for these classes under various ACOS studies are more stable than returns for the SDS and LDS classes.

Columbia's largest class is the residential class representing, on an adjusted basis, approximately 72% of total company revenues and 91% of total company customers. The return index for the residential class ranges from 74.2 under the Customer/Demand study to 108.6 under the Peak & Average study. The average ACOS study produces a residential return index of 89.8, indicating that the class returns are somewhat below parity at present rates. In developing the proposed rates for the residential class, Columbia sought to increase the revenue requirement of the residential class to move toward parity with the overall total company return. Columbia proposes to increase the unitized return from the current 0.89804 to .94300, a 5.0% increase toward parity.

The SGSS/SCD/SGDS return indices are 110.3 for the Peak & Average study, 165.7 for the Customer/Demand study, and 134.7 for the average ACOS study, indicating that the class returns are somewhat above parity at present rates. In developing the proposed rates for the SGSS/SCD/SGDS class, I looked at the current unitized return. The class's return is 1.34730, which is above parity with total company; therefore, Columbia is proposing to apportion less of an increase to the SGSS/SCD/SGDS class so that the unitized returns drop to 1.20130, which is a gradual approach toward parity.

The SDS/LGSS return indices are 79.4 for the Peak & Average study, 225.6 for the Customer/Demand study, and 131.1 for the average ACOS study, indicating that the class returns are somewhat above parity at present rates. In developing the proposed rates for the SDS/LGSS class, I looked at the current unitized return. The

class's return is 1.31067, which is above parity with total company; therefore, Columbia is proposing to apportion less of an increase to the SDS/LGSS class, so that the unitized returns drop to 1.20130, which is a gradual approach toward parity and in line with the SGSS/SCD/SGDS rate class that is also currently above parity.

The LDS/LGSS return indices are 20.8 for the Peak & Average study, 296.7 for the Customer/Demand study, and 84.2 for the average ACOS study, indicating that the class returns are somewhat below parity at present rates. In developing the proposed rates for the LDS/LGSS class, I looked at the current unitized return. The class's return is 0.84227, which is below parity with total company; therefore, Columbia is proposing to apportion more of an increase to the LDS/LGSS class, so that the unitized returns raises to 0.84275, which is a gradual approach toward parity and limits the increase to the LDS/LGSS class base rate revenue recovery to 15.10% as compared to the system average of 14.09%.

The return for the Main line Distribution Service ("MLDS")/Negotiated Sales Service ("NSS") classes indicates that, by directly assigning mains investment, the return is the same under each of the three ACOS studies showing a return that is above parity with a return index of 3,621.0 at present rates. I note that the MDS class is unique, in that all customers are located on, or near interstate pipelines. The Company has historically, and in this case continues to, directly assign mains and services to the rate class. Rates for the class, and the customers served under the rate class have not changed for some period of time. In developing the proposed rates for the MLDS/NSS class, I looked at the current unitized return. Because the

class's return is 3.6210, which is materially above parity with total company; Columbia is proposing no increase in revenue requirement to the MLDS/NSS class, so that the unitized returns drop to 2.69620, which is a gradual approach toward parity.

Q. What is the primary goal of Columbia's class revenue allocation?

A. The primary goal in Columbia's approach to revenue allocation is to maintain a movement toward parity among the various rate classes, consistent with Commission decisions in previous Company rate cases. Movement toward parity is a way of assuring that the revenue allocation process takes into account the overall Company return and the relative returns by rate class. Each class's revenue increase is determined within the context of other rate class returns so that, over time, interclass returns remain close to one another rather than diverging. Maintaining a movement toward parity is a way to reduce potential cross-subsidization between classes.

Q. Do the Company's proposed rate increases for the various rate classes reflect the principle of gradualism?

A. Yes, in two ways. First the Company's proposed rate increases for the various rate classes cause a movement of the unitized returns toward parity (unitized return of 1.00000) for each of the rate classes but with no rate class yet reaching parity. Secondly, the range of base rate revenue increase percentages (excluding the MLDS class) is 10.64% to 15.11% where the system average is 14.09% (see Exhibit 103, Schedule No. 8, Page 1, Lines 17 through 28).

Q. Please describe the Company's proposed revenue allocation.

A. Columbia's allocation of the proposed base rate revenue increase, which is shown in Exhibit 103, Schedule No. 8, Page 4, Line 23 reflects the following allocations: 77.68 % of the overall increase is applied to the residential class; 13.32 % of the overall increase is applied to the SGSS/SCD/SGDS class; 3.83 % of the overall increase is applied to the SDS/LGS class; 5.17 % of the overall increase is applied to the LDS/LGS class; and 0.00 % of the overall increase is applied to MLDS/NSS customers. As a result, the proposed unitized return for the residential class will be .94300, or 94.3 %, as compared to the overall total company unitized return of 1.00000 or 100 %, an increase of 5.0 %. This percentage increase recognizes that the current residential return is lower than the overall return. Similarly, the SGSS/SCD/SGDS class would receive a 10.8 % decrease in unitized return, the SDS/LGSS class would receive an 8.3 % decrease in unitized return, and the LDS/LGSS class would receive a 0.6 % increase in unitized return, which brings those classes closer to parity with the overall return, as measured by the results of the Average ACOS Study. The MLDS/NSS class would receive a 25.5 % decrease in unitized return, as a result of assigning no increase to the class. I note that for all classes the allocated increases and resulting unitized returns fall within the zone of reasonableness founded by the Peak & Average and Customer Demand Studies. Exhibit 103, Schedule 8, Page 4, Lines 4 and 5 shows the movement toward parity produced by Columbia's proposed revenue allocation using the average ACOS

Study. The movement toward parity (unitized return of 1.00000) measures each class's return versus the total company return under current and proposed rates.

III. RATE DESIGN

Q. Other than the Class COS studies, what guidelines or criteria have you considered in the design of the Company's rates?

A. There are a number of criteria that I considered in the design of rates, including the following:

First, the design of Columbia's rates recognizes that rates must be just and reasonable and must not be unduly discriminatory. Columbia's proposed rate design also attempts to minimize cross-class subsidies.

Second, where rates require adjustment to achieve proper cost recovery, customer impact considerations have been factored into the rate design process. For instance, Columbia's proposed rate design moves each of the rate classes toward parity (unitized return of 1.00000 and a total company required rate of return of 8.140 %) but recognizes a move to full parity of 1.00000 in this case would not be consistent with the principle of gradualism.

Third, Columbia's proposed rate design provides for recovery of an increasing proportion of fixed costs through the Customer Charge. This objective recognizes that the historical recovery of fixed costs through the volumetric rate portion of the rate schedule inevitably results in the over or under recovery of those costs because the revenues generated from customers' volumetric use of gas can be greatly sensitive to customer usage fluctuations that vary due to conservation efforts

or other changing consumption characteristics. In essence, customer-related costs that bear no relationship to customer gas consumption patterns should be recovered through the fixed portion of the rate design, i.e. the monthly Customer Charge. Columbia's proposed rate design thus recovers a gradual increase in revenue through the Customer Charges for each of the rate classes.

Q. Why is there a need to increase the percent of base rate recovery through the customer charge now that Columbia has a Weather Normalization Adjustment ("WNA") mechanism?

A. The WNA normalizes the impact of weather on the recovery of residential usage based base revenue (outside a 5% band) during the months when the WNA is in effect. In doing so, the WNA affords the Company a greater opportunity to recover its authorized revenue requirement from its residential and small general service customer, while mitigating the impact of weather on the level of revenues collected from them. Thus, the WNA mechanism is beneficial to both Columbia and its customers. However, the WNA mechanism is not intended to address usage fluctuations that are attributable to conservation efforts or other changing consumption characteristics, intra-class subsidization of fixed cost recovery, weather effects of consumption outside the five winter months that the WNA is in effect, the weather effects of consumption within the 5% WNA band, or weather effects of consumption for rate classes not covered by the WNA. It is for these reasons that it is important for the customer charges to recover an increased percent of base rate revenue recovery.

Q. How are proposed changes in the Company's customer charges determined?

A. Exhibit MPB-2, attached to my testimony, shows the percent of base rate revenue recovery (excluding flexed revenue) by rate class over Columbia's last five rate cases. As can be seen by the exhibit, for many of the rate classes, the current revenue recovery distribution between the customer charges and the usage based charge is the lowest it has been since before the Company's 2008 rate case. The Company's proposal for rates in this case is to align the percentage of customer charge recovery to total base rate recovery just below the average of the five previous rate cases percentage of customer charge recovery for each of the rate classes over the five previous rate cases. The exception is the MLDS rate class, where the Company is proposing to keep the current customer charges because the Company is proposing no increase in revenue requirement to the MLDS class.

Q. Please explain the rationale for increasing Customer Charges to reflect the recovery of a proportion of fixed non-gas costs.

A. It is reasonable and appropriate to collect a proportion of fixed non-gas costs through the fixed monthly Customer Charge. For example, as stated above, for Columbia, just over 35.4% of its delivery charge revenue is currently recovered through the usage based delivery charges to its residential customers. Even with my proposed increase in the Customer Charge, the residential percentage increases only slightly to 38.0% of distribution charge revenue and will still be below the average of the last five rate cases of 38.2% (See Exhibit MPB-2). Fixed cost recovery through the fixed monthly Customer Charge decreases the likelihood and

magnitude of customers' over- or under-payments for distribution service each month due to usage fluctuations, recognizing that a natural gas utility's customer-related costs do not vary with gas usage. Even after the proposed changes to existing Customer Charges for each of the rate classes, all of the Customer Charges are in the range of the Customer Charges that supports the cost of a minimum system shown on Exhibit 111, Schedule 1, Pages 14 and 17, Line 37, and all except the MLDS rate class are below the average of the last five rate cases' percentage of fixed cost recovery (See Exhibit MPB-2).

Q. Please explain the benefits to Columbia and its customers of increasing the proportion of fixed non-gas costs recovered through the monthly Customer Charge.

A. In addition to the decreased likelihood and magnitude of customers' over- or under-payments for delivery service discussed previously, there are a number of other significant benefits from increasing the proportion of fixed non-gas costs covered through the monthly charge. These include increased stability and predictability of customers' bills, greater simplicity and understandability of customers' bills, a corresponding reduction in bill complaints, and mitigation of intra-class cross subsidization. Additionally, the increased reliance on Customer Charges for fixed cost recovery should reduce the magnitude of annual true-ups for customers participating in Columbia's budget payment plan.

At a minimum, maintaining the relative proportion of fixed non-gas costs recovered through the monthly Customer Charge at the average for the past five years more closely matches the Commission-approved level of revenue with costs.

Q. Please summarize Columbia's residential rate design proposal.

A. Columbia proposes a modest increase the Residential Customer Charge from the current $16.75 per month to a $20.60 per month charge. It should be noted that $20.60 is between the $18.15 and $35.90 minimum system cost-based Customer Charges shown in the ACOS study (Exhibit 111, Schedule 1, Page 14, Line 40 and 17, Line 37). It should also be noted that the Company currently only recovers 35.4% of its residential distribution costs through the customer charge. Even with a $3.85 increase in the customer charge, the percentage only increases to 38.0%, which is still below the last five rate case average of 38.2%. Finally, it should be noted that Columbia has no decoupling mechanism to ensure a reasonable opportunity to recover cost of service. Therefore the Company relies on the customer charge for protection from usage erosion from customers switching to more efficient furnaces and appliances and Columbia's energy efficiency program.

Q. Will CAP customers receive a rate increase as a result of this rate proceeding?

A. No. The revenue increment that is assigned to CAP customers will be collected from other residential customers through Rider USP.

Q. Please summarize Columbia's SGSS/SCD/SGDS rate design proposal.

A. The proposed SGSS/SCD/SGDS Customer Charge for customers whose usage is less than 6,440 therms is $27.75. At $27.75, the volumetric base rate will be $3.5027/Dth for SGSS/SCD service and $3.2846/Dth for SGDS service.

The proposed SGSS/SCD/SGDS Customer Charge for customers whose usage is between 6,440 therms and 64,400 therms is $55.50, which is $7.50 more

than the current $48.00. With the increase in the customer charge, the percentage of distribution costs by the customer charge will only increases to 22.1% from the current 20.1%, which is still below the last five rate case average of 22.4%.

Q. Does the SGSS, SCD, and SGDS rate class split the volumetric base rate between what is charged to SGSS and SCD customers from what is charged to SGDS customers?

A. Yes. Per the approved settlement in Docket No. R-2012-2321748, Columbia agreed to re-allocate $530,000 of storage working capital costs from SGDS to SGSS/SCD. Per the approved settlement in Docket No. R-2014-2406274, Columbia agreed to re-allocate $710,000 of storage working capital costs from SGDS to SGSS/SCD. As part of this current proceeding, and explained by Company witness Elliott in testimony and shown on Exhibit BEE-2, the Company has re-allocated $597,433 of storage working capital costs from the SGDS class to SGSS/SCD. This intra-class re-allocation is shown on Line 19 of Exhibit 103, Schedule 8, Page 6. As a result, the Company charges a different volumetric base rate to the SGSS and SCD customers than to the SGDS customers and that principle will not change under proposed rates.

Q. What is the Company's basis for further splitting the current SGSS, SCD and SGDS rate class volumetric base rate charges into two separate charges?

A. The current SGSS, SCD, and SGDS tariff rates are made up of a monthly Customer Charge and volumetric base rate per therm for those commercial and industrial customers whose annual usage is less than 6,440 therms annually or between 6,440

therms and 64,400 therms annually. The current rate design for these tariffs charges a $21.25 Customer Charge for those customers who use less than 6,440 therms on an annual basis and $48.00 Customer Charge for those customers who use between 6,440 therms and 64,400 therms on an annual basis. The reason for the difference in customer charges is simple. As customers require greater capacity, cost of meters, service lines, regulators, and other customer based costs are greater. However, the volumetric base rate for both those customers whose annual usage is less than 6,440 therms annually and those whose annual usage is between 6,440 therms and 64,400 therms annually under current rate design are the same. The cost of service for the LDS class demonstrates that volumetric base rates per therm should actually decrease as annual consumption increases. The reason is simple: as the fixed cost being recovered through the volumetric base rate (the numerator) is recovered over increased annual consumption (the denominator) the resulting volumetric rate decreases. Under current SGSS/SCD/SGDS volumetric base rates, customers using between 6,440 therms and 64,400 therms annually are paying a disproportionate amount of fixed cost recovery through the volumetric base rates simply because of rate design. The allocated cost of service studies prove this hypothesis. As consumption increases among the rate classes, the cost per therm decreases. Current volumetric base rate design reflects proper cost recovery by gradually lowering volumetric rates as annual consumption increases, with the exception of the SGSS/SCD/SGDS and the SDS rate classes.

Q. What is the Company's proposal to rectify the current inequity between customers whose annual usage is less than 6,440 therms annually and those customers whose annual usage is between 6,440 therms and 64,400 therms annually under the current rate design?

A. The inequity has existed over time and, in the interest of gradualism, over time the Company has aligned the customer charges for the two customer groups. It is now reasonable to finish the realignment of cost recovery for the volumetric rates. The Company is proposing a gradual separation of the volumetric base rate that is currently being billed to these customer groups to lessen the differential in fixed cost recovery between the two groups and reflect a truer match of cost causation with cost recovery. Specifically, the Company is proposing to charge a slightly lower volumetric base rate to customers whose annual usage is between 6,440 therms and 64,400 therms annually than those customers whose annual usage is less than 6,440 therms annually by shifting 5% volumetric base rate recovery from those whose annual usage is between 6,440 therms and 64,400 therms annually to those customers whose annual usage is less than 6,440 therms annually.

Q. Please summarize Columbia's SDS/LGSS rate design proposal.

A. The proposed SDS/LGSS Customer Charge for customers whose usage is between 64,400 therms and 110,000 therms is $215.00. The $215.00 is just $45.00 more than the current SDS/LGSS Customer Charge of $170.00. With the increase in the customer charge, the percentage of distribution costs by the customer charge will

only increases to 16.3% from the current 15.7%, which is still below the last five rate case average of 16.6%.

The proposed SDS/LGSS Customer Charge for customers whose usage is between 110,000 therms and 540,000 therms is $685.00. The $685.00 is just $45.00 more than the current SDS/LGS Customer Charge of $640.00.

Q. Is the Company proposing to charge a slightly lower volumetric rate for the SDS rate class to customers whose annual usage is between 110,000 therms and 540,000 therms annually than those customers whose annual usage is between 64,400 therms and 110,000 therms annually for the same reasons stated above for the SGSS/SCD/SGDS rate class?

A. Yes. The current rate design for this tariff charges a $170.00 monthly Customer Charge for those customers who use between 64,4000 therms and 110,000 therms annually and a $640.00 Customer Charge for those customers who use between 110,000 therms and 540,000 therms on an annual basis. However, they pay the same volumetric base rate. As with the SGSS/SCD/SGDS rate classes, the Company is proposing a gradual separation of the volumetric base rate that is currently being billed to the SDS customer groups by shifting 5% volumetric base rate recovery from those whose annual usage is between 110,000 therms and 540,000 therms annually to those customers whose annual usage is between 64,400 therms and 110,000 therms annually to lessen the differential in fixed cost recovery between the two groups and reflect a truer match of cost causation with cost recovery.

Q. Please describe the current rate design for the LGS rate class.

A. Current rate design has the Large General Sales Service ("LGSS") rate class paying the same customer charges as the SDS rate class for customers whose annual usage is between 64,400 therm and 110,000 therms annually and for customers whose annual usage is between 110,000 therm and 540,000 therms annually. However, the LGSS and SDS rate classes pay completely different volumetric base rates.

Q. Do you agree that the proposed usage-based rates for the LGSS and SDS customers using between 64,400 therm and 110,000 therms annually and whose annual usage is between 110,000 therm and 540,000 therms annually should remain different?

A. No. The only difference between LGSS and SDS service is the upstream supply and capacity charges. As for the distribution service, there is no difference in the service or material difference in the cost to serve this customer group and, therefore, both rate classes should pay the same distribution charges (for consumption less than 540,000 therms annually). LGSS and SDS customers already pay the same customer charges and now should pay the same usage-based charge. The Company combined these two rate classes specifically because they generate a similar cost to serve because of their annual requirements and, therefore, cost recovery rates for the two rate tariffs should be the same.

Q. Please summarize Columbia's LDS/LGSS rate design proposal.

A. The proposed LDS/LGSS Customer Charge for customers whose usage is between 540,000 therms and 1,074,000 therms is $1,800.00. The $1,800.00 is just $500.00 more than the current LDS/LGS Customer Charge of $1,300.

The proposed LDS/LGS Customer Charge for customers whose usage is between 1,074,000 therms and 3,400,000 therms is $2,800. The $2,800 is just $500 more than the current LDS/LGS Customer Charge.

The proposed LDS/LGS Customer Charge for customers whose usage is between 3,400,000 therms and 7,500,000 therms is $5,400. The $5,400 is just 12.5% more than the current LDS/LGS Customer Charge of $4,800.

The proposed LDS/LGS Customer Charge for customers whose usage greater than 7,500,000 therms is $8,000. The $8,000 is just 8.1% more than the current LDS/LGS Customer Charge of $7,400.

With the proposed increase in the LDS customer charges, the percentage of distribution costs by the customer charge would only increases to 16.1% from the current 15.1%, which is still below the last five rate case average of 17.2%.

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 7, Line 30 spread among the LDS/LGSS annual usage groups?

A. Volumetric Base Rate Revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric Base Rates. (See Exhibit 103, Schedule 8, Page 7, Lines 32 through 35).

Q. How does the current rate design address LGSS customers whose annual usage is in excess of 540,000 therms?

A. Current rate design has the LGSS rate class paying the same monthly Customer Charges as the LDS rate class for customers whose annual usage is greater than

540,000 therms. As with the SDS rate class, the only difference between LGSS and LDS service is the upstream supply and capacity charges. As for the distribution service, there is no difference in the service or material difference in the cost to serve this customer group and, therefore, both rate classes should pay the same distribution charges (for consumption greater than 540,000 therms annually). LGSS and LDS customers already pay the same customer charges and now should pay the same usage-based charge. The Company combined the LGSS customers whose annual usage is greater than 540,000 therms with the LDS rate class specifically because they generate a similar cost to serve because of their annual requirements and, therefore, cost recovery rates for the two rate customer groups should be the same.

Q. Why do you propose eliminating the declining rate blocks from the LGSS rate structure?

A. Under the current LGSS rates, there are four rate blocks for monthly usage: 0 to 11,000 therms, 11,001 to 54,000 therms; 54,001 to 108,000 therms; and over 108,000 therms. The current rate blocks are necessary because of the diversity of customers' ACOS within the rate class. However, splitting the LGSS rate class volumetric base rates by their annual consumption groups allows the Company to align revenue recovery for its sales service with that of its distribution service. Columbia already does this with its residential service, SGSS/SCD/SGDS service, and MLDS/NSS service and has already aligned the customer charges among the LGSS, SDS and LDS classes. This step completes the alignment of the volumetric

base rates. The new rate design will be fairer because of the greater homogeneity of ACOS of the new classes. The new rate design will also be simpler because the Customer Charge and new single volumetric rate for each of the new classes render the existing four rate blocks unnecessary.

Because the Company has split the LGS rate class between the SDS and LDS rate classes based upon each class's ACOS, the Company is proposing to eliminate the existing LGS rate blocks with the remainder of the revenue requirement increase to the LGS class falling to a single volumetric base rate for each of the annual consumption customer groups.

Q. Please discuss the rate design proposals for the MLDS/NSS class.

A. Columbia is proposing no change to the customer charge and a slight decrease to the volumetric charges to offset revenue recovery of the proposed CAC charge resulting in a no increase in distribution charge revenue.

Q. Please discuss the rate design proposals for the Main line Sales Service ("MLSS") class.

A. MLSS service applies to the same customer groups that MLDS service applies to with the primary exception that MLSS service is a sales service and MLDS service is a distribution service. There were no MLSS customers served by the Company during the historic test year, nor are there any MLSS customers expected to take service during the forecasted rate year. However, the MLSS tariff is active and it is the Company's intent that customers who elect to be served under the MLSS tariff

pay the same distribution service rates established for the MLDS tariff customers in this case.

Q. Please describe the treatment of flex rate agreements in the development of the Company's base rates.

A. Revenues resulting from flex rate agreements are shown in Exhibit No. 103. Because the flex agreements are individually negotiated, the associated revenues are not increased as a result of the Company's rate case filing.

Q. Do flex rate agreements benefit Columbia's non-flex customers?

A. Yes. Revenue collected from flex rate customers contributes to the recovery of the Company's fixed costs. Without the revenues from the flex customers, non-flex customers would be assigned additional fixed cost recovery responsibility and their rates would increase.

IV. BILL COMPARISONS

Q. How do Columbia's proposed rate design changes affect annual bills for residential and SGSS/SCD/SGDS customers?

A. Examples of typical bills for residential, SGSS, and LGSS customers under current and proposed rates are shown in Exhibit 111, Schedules 5 and 6. The typical bills were developed using gas costs in Columbia's PGC filing, effective January 1, 2015. Based on the proposed revenue requirement, the average residential customer using approximately 6.9 Dth per month would see an overall monthly bill increase of 8.64% under Columbia's proposed rate design, which is reflected in Exhibit 111 Schedules 5 and 6. At an average SGSS usage for customers whose annual usage is

less than 6,440 therms of approximately 16.6 Dth per month, a typical monthly bill would increase by 7.07% under proposed rates. At an average LGSS usage for customers whose annual usage between 6,440 and 64,400 therms of approximately 117.3 Dth per month, a typical monthly bill would increase by 1.78% under proposed rates. At an average LGSS usage of approximately 676 Dth per month, a typical monthly bill would decrease by -3.35% under proposed rates.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Cost of Service Study Results
For the 12 Months Ending December 31, 2016

	Peak & Average		Customer/Demand		Average Study	
	Return	Index	Return	Index	Return	Index
Residential Service (RS/RDS)	6.584%	108.6	4.494%	74.2	5.443%	89.8
Small General Service (SGSS/SCD/SGDS)	6.686%	110.3	10.042%	165.7	8.166%	134.7
Small Distribution Service (SDS/LGSS)	4.814%	79.4	13.676%	225.6	7.944%	131.1
Large Distribution Service (LDS/LGSS)	1.261%	20.8	17.984%	296.7	5.105%	84.2
Mainline Distribution Service (MLDS)	219.470%	3,621.0	219.470%	3,621.0	219.470%	3,621.0
Total Company	6.061%	100.0	6.061%	100.0	6.061%	100.0

Columbia Gas of Pennsylvania, Inc.
Base Rate Fixed Cost Recovery
For the 12 Months Ending December 31, 2016

	2008	2010	2011 2/	2012	2014	5 Case Average 3/	Proposed 2015	Difference
Residential Service (RS/RDS)								
Customer Charge Revenue	52,191,199	55,804,410	85,183,066	77,259,358	78,381,874		96,908,868	
Base Rate per Dth Revenue	86,046,002	84,572,528	64,221,831	116,137,004	142,844,682		158,359,650	
Total Base Rate Recovery	138,237,201	140,376,938	149,404,897	193,396,362	221,226,556		255,268,518	
Customer Charge Recovery Percent of Total	37.755%	39.753%	57.015%	39.949%	35.431%	38.222%	37.964%	-0.258%
Small General Service (SGSS/SCD/SGDS) 1/								
Customer Charge Revenue	8,251,948	8,656,237	9,598,846	10,305,040	11,089,775		14,103,385	
Base Rate per Dth Revenue	33,800,244	26,943,030	27,287,894	36,944,451	44,105,641		49,704,276	
Total Base Rate Recovery	42,052,192	35,599,267	36,886,740	47,249,491	55,195,416		63,807,661	
Customer Charge Recovery Percent of Total	19.623%	24.316%	26.022%	21.810%	20.092%	22.373%	22.103%	-0.270%
Small Distribution Service (SDS/LGSS) 1/								
Customer Charge Revenue	1,502,080	1,567,843	1,777,454	2,112,274	2,302,200		2,549,625	
Base Rate per Dth Revenue	7,455,074	7,561,578	7,743,183	12,199,753	12,356,098		13,066,951	
Total Base Rate Recovery	8,957,154	9,129,421	9,520,637	14,312,027	14,658,298		15,616,576	
Customer Charge Recovery Percent of Total	16.770%	17.174%	18.669%	14.759%	15.706%	16.616%	16.326%	-0.290%
Large Distribution Service (LDS/LGSS) 1/								
Customer Charge Revenue	1,398,392	1,343,244	1,436,538	1,671,952	1,714,800		2,330,000	
Base Rate per Dth Revenue	6,102,827	6,257,254	6,635,955	8,197,230	9,623,494		12,141,682	
Total Base Rate Recovery	7,501,219	7,600,498	8,072,493	9,869,182	11,338,294		14,471,682	
Customer Charge Recovery Percent of Total	18.642%	17.673%	17.795%	16.941%	15.124%	17.235%	16.100%	-1.135%
Mainline Distribution Service (MLDS) 1/								
Customer Charge Revenue	50,844	93,540	104,352	68,620	65,964		79,752	
Base Rate per Dth Revenue	149,641	151,087	136,159	152,388	149,964		135,443	
Total Base Rate Recovery	200,485	244,627	240,511	221,008	215,928		215,195	
Customer Charge Recovery Percent of Total	25.361%	38.238%	43.388%	31.049%	30.549%	33.717%	37.060%	3.343%

1/ Excludes Flexed Base Rate Revenue
2/ Residential Customer Charge included recovery of the first 2.1 Dth per month.
3/ 2011 is excluded from the average for the Residential class because the recovery of the first 2.1 Dth was included with the Customer Charge.

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NANCY J.D. KRAJOVIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

I. Introduction

Q. Please state your name and business address.

A. Nancy J. D. Krajovic, Southpointe Industrial Park, 121 Champion Way, Suite 100, Canonsburg, PA 15317

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Director of Regulatory Affairs.

Q. What are your responsibilities as Director of Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I hold a Bachelors of Science Degree in Accounting from Duquesne University and a Master of Business Administration from the University of Pittsburgh's Katz Graduate School of Business. I was employed by the Commission from 1984 through 1987 as an auditor. From 1988 through 2007, I held various regulatory positions at Duquesne Light Company including Regulatory Analyst, Rate Design Coordinator, Project Manager, Director of Regulatory Affairs and Manager of Regulatory Affairs. In those positions I acted as the primary interface with the Commission in the conduct of financial and management audits of Duquesne Light. Additionally, I was responsible for the interpretation and administration of

Duquesne's retail and supplier tariffs. In 2007, I assumed the role of Manager, Commercial and Industrial Customers for Duquesne Light and held that position until May, 2009. In November of 2009, I joined Columbia Gas as Senior Regulatory Analyst and was promoted to my current position in June of 2011.

Q. Have you previously testified before this Commission?

A. Yes, I have submitted written testimony before the Commission on Duquesne's behalf at the following dockets: I-900005, M-00930404C001, R-00016854C001, M-FACE0302, R-00061346 and P-00072247. I also presented oral testimony in several formal customer complaint actions and at en banc hearings sponsored by the Commission on energy conservation issues. Additionally, I have submitted written testimony before the Commission on behalf of Columbia at the following dockets: R-2011-2215623, R-2012-2293303, R-2012-2321748, R-2013-2351073, R-2014-2406274, R-2014-2408268, P-2012-2338282 and C-2011-2248370/A-2011-2276780.

Q. What matters will you address in your testimony?

A. I will describe the calculation of the Rider Customer Choice adjustment ("Rider CC") and the Gas Procurement Charge ("GPC") included in this case. I will also present the Company's proposed Rider Choice Administration Charge ("Rider CAC"). Lastly, I will discuss proposed changes to Columbia's Universal Service Programs.

I. Rider Customer Choice Adjustment

Q. Please describe the update to Rider CC.

A. The Rider CC charge included in this case is $0.00010 per therm to be billed to all CHOICE® eligible customers.

Q. What costs are recovered through this charge?

A. Rider CC recovers costs associated with the triennial solicitation mailing to customers notifying them that their names are included on eligibility lists provided by Columbia to all NGSs offering gas supply to customers in Columbia's service territory. Columbia will conduct this triennial solicitation pursuant to the Commission's Final Order of August 15, 2013 at Docket No. M-2012-2324075, Interim Guidelines For Natural Gas Distribution Company Eligible Customer Lists, which states:

> That once every three years NGDCs will create a new ECL by re-soliciting their entire residential and small commercial customer base about their options regarding the disclosure of their customer information to NGSs.

Q. Are the solicitation costs recoverable?

A. Yes, the Commission in its Final Order determined that incremental costs for soliciting customers are subject to cost recovery.

Q. What costs will the proposed charge of $0.00010 per therm recover?

A. The costs included for recovery are for materials, preparation and postage that will be provided by a third party vendor to accomplish the solicitation that will occur in 2016 to all CHOICE® eligible customers. Because the solicitation will occur every three years, the rate has been calculated to recover each year from CHOICE® eligible customers one-third of the projected costs to comply with the Interim Guidelines requirement for a triennial re-solicitation. The calculation is shown on

Exhibit NJDK-1, attached to my testimony.

II. Gas Procurement Charge ("GPC")

Q. Has the Company recalculated the surcharge rate for the Gas Procurement Charge?

A. Yes. Please refer to Exhibit NJDK-2, page 1 of 1, attached to my testimony, for the calculation of the surcharge.

Q. What categories of costs are included in the GPC?

A. The GPC includes the labor and benefits costs associated with gas procurement activities defined by function and include external legal costs. Information Technology Systems expense is the portion of maintenance costs associated with Gas Source that is allocated to Sales Service customers.

Q. Is the Company proposing any changes to the categories of costs included in the GPC?

A. No.

III. Choice Administration Charge ("CAC")

Q. What is the Choice Administration Charge?

A. The Choice Administration Charge, found on Tariff Page 164, is a Rider ("Rider CAC") that will be applied to accounts served under Rate Schedules Residential Distribution Service ("RDS"), Small Commercial Distribution ("SCD"), Small General Distribution Service ("SGDS"), Small Distribution Service ("SDS"), Large Distribution Service ("LDS"), and Main Line Distribution Service ("MLDS"). Through the charge, Columbia will recover costs it incurs to administer and

maintain the Choice Program and General Distribution Service Program ("GDS") on Columbia's system.

Q. How will the Rider CAC be charged?

A. Columbia is proposing that the Rider CAC be billed as a per therm rate for Choice customers and included in the Pass-through Charge line item on their bills. For a breakdown of the components of the Pass-through Charge, including the Rider CAC, and the Rate Schedules to which the Pass-through Charge will be billed, please see Exhibit No. 14, Schedule 2, Attachment 2, which reflects the proposed tariff changes. Exhibit No. 14, Schedule 2, Attachment 2, Eighteenth Revised Tariff Page No. 21b is the Pass-through Charge Summary listing each Rate Schedule subject to the Pass-through Charge, and the components that make up the Pass-through Charge rate that appears on a customer bill. There is a separate column labeled "Rider CAC" detailing the rate and the Rate Schedules that are affected by the Rider CAC.

For GDS customers, the Company proposes to include the Rider as a fixed per account charge on a separate line item on the bill labeled "Choice Administration Charge."

Q. Please explain Exhibit NJDK-3.

A. Exhibit NJDK-3, attached to this testimony, calculates a charge to Choice Program and GDS customers for the costs associated with providing distribution service. The costs included in the calculation are labor and benefits, Information Technology ("IT") expense, and system expense associated with the Company's

Aviator system. Total expense of $959,917.96 was allocated between Choice and GDS customers. The $513,100.06 allocated to Choice customers was divided by Fully Forecasted Rate Year Distribution Dth for Rate Schedules RDS and SCD of 10,283,070.07 Dth to compute a rate of $0.04990/Dth, or $0.00499/therm. The DTH are shown on Exhibit 103, Schedule 1, Page 15, line 38 and Page 16, line 27. The $446,817.90 allocated to GDS customers was divided by the number of billed accounts forecasted for GDS customers (excluding customers with flexed rates) of 32,691 which are shown on various lines of Exhibit 103, Schedule 1, Page 15, line 38 and Page 16, line 27 to produce a per account charge of $13.67.

Q. Is Rider CAC designed to be reconcilable?

A. Similar to Rider GPC - Gas Procurement Charge, Rider CAC is not designed to be reconcilable.

Q. Where does the Rider CAC appear on pages 16-21c of the tariff?

A. The Rider CAC appears on the Rider Summary, Tariff Page No. 21, and the Pass-through Summary, Tariff Page No. 21b, as well as on Tariff Pages No. 17, 18 and 19 as a per account charge for non-flex rate customers taking service under Rate Schedules SGDS, SDS, LDS and MLDS.

Q. Why is the Company proposing Rider CAC?

A. Columbia's proposed Rider CAC is consistent with the Commission's existing regulations. Specifically, Title 52 Section 60.1 of the Pennsylvania Code specifies:

> The transportation of natural gas by jurisdictional gas utilities is in the public interest. Transportation service should be provided under terms, conditions and rates which minimize the shifting of costs to retail customers and

provide the natural gas utility with an opportunity to recover the fixed costs incurred to serve the transportation service customers.

Through Rider CAC, Columbia seeks to address cost causation for expenses associated with gas transportation programs. Rider CAC is designed to recover expenses the Company incurs solely to administer, enhance, and maintain gas transportation programs.

Further, the Company's proposal is based on the Commission's Final Order at Docket No. L-2008-2069114 *Natural Gas Distribution Companies and Promotion of Competitive Retail Markets*. Through Rider CAC, the Company proposes to further unbundle its rates. Specifically, in its Order the Commission directed natural gas distribution companies to remove costs associated with the purchase of gas supply from base rates and add them to their Gas Supply Charge. Columbia submits that the proposed Rider CAC is consistent with the unbundling of the costs underlying the Gas Procurement Charge.

Q. Please further explain the reasoning behind this proposal.

A. Columbia currently incurs costs that are solely attributable to the administration and maintenance of the Choice Program and GDS, and those costs are recovered through base rates. Accordingly, Columbia's Sales Service customers are currently paying for the administration and maintenance of programs for which they receive no benefit. Columbia has identified a portion of those costs that are currently included in base rates. Segregating a charge to the Choice customer and GDS customer bills for costs arising from the program in which they participate is simply the logical approach to cost recovery.

Q. Please further detail the costs that make up Rider CAC.

A. The Rider CAC includes labor costs for employees whose job responsibilities are directly impacted by the Choice Program and GDS, and IT programming costs the Company incurs to enhance and maintain the systems that support the Choice Program and GDS.

Q. How are the labor costs identified?

A. The labor costs represent payroll, benefits, and taxes that Columbia incurs for twenty-seven employees who spend 100% of their Columbia time working on either the Choice Program or GDS, or both. If Columbia did not have a Choice Program or GDS program, these employee positions, and their associated costs, would not exist. It also includes labor for five support personnel and management level employees with a range of 2% to 10% of their time spent on the Choice Program and GDS for the Company.

Q. Are all labor costs associated with the Choice Program and GDS included in the Rider CAC calculation?

A. No. While there are several other employees from departments such as Legal, Regulatory, Accounting, Accounts Payable, Large Customer Relations, etc., who spend some of their time working specifically on the Choice Program and/or GDS tasks, Columbia did not include their labor in the calculation.

Q. Why did Columbia not include that additional labor cost?

A. Those other department employees work on various types of tasks for multiple purposes. The time spent by these departments relative to the Choice Program and

GDS are limited and intermittent compared to the labor costs that have been included in the Rider CAC calculation.

Q. How are the IT system programming and maintenance costs identified?

A. Columbia researched the amount of hours and associated costs spent on programming changes and maintenance activities generated by the Choice Program or GDS during the test year. Any programming requests that impacted GDS, the Choice Program, and Sales Service together were not included.

Q. Are the costs to be recovered through Rider CAC included in the Company's proposed base rates in this case?

A. No. The costs to be recovered through Rider CAC have been backed out of the base rates calculated by Company witness Lai (Columbia Statement No. 3).

Q. Is there anything else you want to add about the Rider CAC?

A. Since the beginning of the Choice Program on Columbia's system in 1996, Sales Service customers have shared the cost to develop and maintain the Choice Program. They have paid for computer programming and internal labor, as well as customer education, for nearly two decades and continue to do so. Rider CAC is Columbia's attempt to further unbundle the Choice Program costs in the interest of recovery based on cost causation.

IV. Universal Service Programs

Q. Does Columbia propose changes to its Universal Service programs?

A. Yes. The Company proposes to modify the funding levels and eligibility requirements for its Emergency Repair Program ("ERP") as well as its method of

recovering these costs. In addition, Columbia proposes to recover the administrative costs associated with its Customer Assistance Program ("CAP") through its Rider Universal Service Program ("Rider USP") rather than through base rates.

Emergency Repair Program

Q. Can you please describe the Company's existing ERP program?

A. Yes, ERP was established in 1995 to assist low income customers at 150% of the federal poverty level ("FPL") guidelines or less with heating related emergencies such as the repair or replacement of house and service lines, heating systems and water tanks. When established, the annual program funding was set at $250,000 and recovered through base rates.

Q. Have any modifications been made since 1995?

A. Yes. In the Commission-approved Settlement of Columbia's 2010 base rate case at Docket No. R-2009-2149262, the Company received approval to increase annual ERP funding to $500,000. The increase in funding was necessary in order for the Company to respond to the significant demand on the program, which resulted in the ERP exhausting available funds prior to the end of the year. From the outset of the program, Columbia had to close the program during the summer months, when the need for repairs is not critical to maintaining heat, in order to have funding available during the heating months beginning in October.

Q. How is the program made available to customers?

A. Customers who are in contact with the Company because their service has been interrupted due to equipment failure or safety concerns and are income qualified are referred to the program.

Additionally, in 2013 the Company launched Heat Wise, a partnership with Heating, Ventilation & Air Conditioning ("HVAC") contractors and Columbia employees to promote the safe operation of heating systems to elderly and disabled low-income customers. Through Heat Wise, annually in September, HVAC contractors and Columbia employees make Saturday visits to pre-screened low income property owners and perform heating system clean and tunes and safety inspections free of charge. Although the clean and tunes are performed by HVAC volunteers free of charge, any problems identified are then covered through the ERP program. In the last two years, over $100,000 of the ERP budget has been spent on this pro-active program.

Q. Is Columbia growing the potential customer base for ERP through this outreach?

A. No. The customers contacted through Heat Wise would need equipment repair or replacement when their furnaces are turned on at the onset of colder weather and would have been referred to ERP at that time. Through Heat Wise the repairs or replacement are completed before these customers are faced with no heat and cold temperatures.

Q. What changes are being proposed to ERP by Columbia?

A. Columbia is proposing three changes to the ERP program. First, the Company proposes to increase the ERP program budget from $500,000 to $600,000. The

increase in funds will assist Columbia to keep the program open year round. Second, the Company proposes to recover ERP program costs through Rider USP, with an offsetting adjustment to the O&M claim in this case, instead of through base rates. Third, the Company is proposing to raise the eligibility guidelines from 150% of FPL to 200% to assist with hardship cases.

Q. Has funding at the $500,000 level been sufficient to reach those goals of meeting demand and keeping the program open all year?

A. Not entirely. The increased funding level has enabled the Company to assist more eligible customers, but Columbia still is not able to maintain the program all year.

Q. What types of emergencies arise in the summer months?

A. Typically customers are faced with a need to repair or replace leaking house or service lines discovered by the Company during required leak inspections. In the western portion of Columbia's territory customers own and are required to maintain their service lines. Repairs or replacement can be costly and are necessary before the onset of the next heating season. Of the leaks found in 2014, 46% of the affected customers were level 1 (150% of poverty and below) and an additional 11% were between 150% and 200% of poverty. When these events arise during the summer months, customers find themselves in an emergency situation. However, by this time funding for the ERP program is exhausted and the Company has no assistance to offer the customers.

Q. Please explain why Columbia is proposing to recover ERP costs through Rider USP.

A. The benefits of Rider USP recovery are two-fold: (1) if the $600,000 ERP funding levels are not exhausted in a given year, then Columbia will not recover the unspent program funds; and, (2) recovery of ERP costs through Rider USP will align ERP cost recovery with the Company's other Universal Service Programs and ensure that the recovery of ERP costs will be from the residential customer class, to whom the benefits inure.

Q. Why is Columbia proposing to expand the eligibility requirements for ERP from 150% to 200% of FPL?

A. As noted above, of the leaks found in 2014, 46% of the affected customers were level 1 (150% of FPL and below) and an additional 11% were between 150% and 200% of FPL. By expanding the eligibility for ERP, coupled with the increase in the funding level for the program, Columbia will be able to provide further assistance to customer that are at or near 150% of the FPL.

Q. Is Columbia proposing to limit the amount of funds spent on customers between 151% and 200%?

A. Yes, Columbia proposes to spend no more than 10% of the ERP budget to assist these hardship cases. Currently, the Company has to refuse assistance to customers who are just over the income guideline but have high expenses such as medical or pharmaceutical expenses. Although the Company recognizes the financial hardship of this large and unexpected repair, the existing program guidelines will not permit assistance to this customer. The proposal as stated here is consistent with the

approach Columbia currently employs in operating it Low Income Usage Reduction Program.

Q. Is there any precedent for the changes that Columbia is proposing?

A. People's Natural Gas Company also has an ERP. Their program is funded through their Universal Service Rider and is available to customers up to 200% of poverty level.

CAP Administration Costs

Q. Please describe the current recovery of CAP application and administration costs.

A. Columbia contracts with a third party to administer the CAP program. Applications are taken over the phone or in person at community based agencies. The cost to take the phone application or pay a local community based agency is charged to Columbia and recovered through Rider USP. The cost for the third party to verify the income documentation, process and store applications is billed monthly to the Company and is currently reflected in base rates. Over the years, the "flat" monthly fee has shifted in proportion to the fluctuation of CAP application levels. Most recently in 2014, Columbia experienced an increase in CAP applications and enrollments; as a result, additional third party resources were needed in order to ensure applications were processed in a timely fashion. The fluctuating nature of the CAP administration costs makes it appropriate for inclusion with other CAP costs in the Rider USP. This is also consistent with other treatment of CAP administrative cost recovery by other Pennsylvania utilities as approved by this Commission.

Q. Does this complete your direct testimony?

A. Yes, it does.

Projected Rider CC Charge for Tri-ennial Eligible Customer List Refresh

CHOICE Eligible Customers/Usage

Rate Schedules subject to Rider CC, Tariff Page No. 148	No. of Bills	No. of [1] Customers	Projected Usage [2]
RSS	3,377,134	281,428	23,280,676.1
RDS	1,069,855	89,155	8,134,026.3
SCD	99,579	8,298	2,149,044.4
PS	0	0	0.0
SGSS	317,107	26,426	9,128,567.8
SGDS	27,076	2,256	3,862,725.8
DGDS	0	0	0.0
Total customers and usage		407,563	46,555,040.4
Total adjusted customers/usage		407,563	46,555,040.4

1 - From Exhibit 103 Schedule 2, Column 7
2 - From Exhibit 103 Schedule 3, Column 6

Total Projected Expenses	$142,945.00
Annualization	3
Annual Recovery	$47,648.33
Projected Annual Usage in therms	465,550,404.0
Rider CC Rate - per therm	0.00010

Columbia Gas of Pennsylvania, Inc.
Gas Procurement Charge

1	**Labor and Benefits** [1]			
2	Accounting Support	37,795.82		
3	Gas Supply Support	235,655.92		
4	Legal Support	30,728.78		
5	Regulatory Support	172,424.58		
6	Total Labor and Benefits		$476,605.10	
7				
8	**Outside Services - Legal Support**		40,197.36	
9				
10	**Information Technology Systems Maintenance**			
11	Gas Source	53,614.31		
12	% of customers taking Sales Service	72.00%		
13	Cost allocated to Sales Service Customers		38,602.30	
14				
15	**TOTAL (line 6 + line 8 + line 9)**		$555,404.76	
16				
17	Total Sales (Therms)		334,239,844	[2]
18				
19	Gas Procurement Charge (Line 11 / Line 13)		$0.00166	per / therm
20	Gas Procurement Charge (Line 15 * 10)		$0.01660	per / Dtth

(1) Labor charges include payroll, benefits and taxes.

(2) Fully Forecasted Rate Year Gas Service Sales per Exhibit 103, Schedule No. 1, Page 15, line 22 LESS Rate NSS Sales found on Exhibit 103, Schedule No. 1, Page 13, line 53, as Rate NSS is not subject to GPC.

Columbia Gas of Pennsylvania, Inc.
Calculation of Rider CAC Charges

		CHOICE [1]	GDS [2]
Aviator	71,486.90	19,918.90	51,568.00
GDS	9,262.00	0	9,262.00
CHOICE	186,706.80	186,706.80	0
Total IT Costs to CHOICE/GTS	$267,455.70	$206,625.70	$60,830.00
Labor	$692,462.26	$306,474.36	$385,987.90
Total CAC costs to be recovered	**$959,917.96**	$513,100.06	$446,817.90
Volumes [3]	305,451,637.0	102,830,707.0	202,620,930.0
# of accounts [4]	1,202,125.0	1,169,434	32,691
Rate per therm	0.00314	**0.00499**	0.00221
Rate per account	$0.80	$0.44	**$13.67**

[1] - Rate Schedules RDS and SCD

[2] - Rate Schedules SGDS, SDS, LDS, MLDS

[3] - Total Transportation volumes less Flex and CAP volumes

[4] - Total Distribution Service accounts less Flex and CAP accounts

	Accounts	DTH
RDS	1,069,855	8,134,026.3
SCD	99,579	2,149,044.4
Total CHOICE	1,169,434	10,283,070.7
SDS (non-flex)	4,615	5,821,184.6
SGDS (non-flex)	27,076	3,862,725.8
LDS (non-flex)	952	10,172,182.6
MLDS I (non-flex)	36	146,000.0
MLDS II (non-flex)	12	260,000.0
Total GTS	32,691	20,262,093
CAP	257,325	2,512,973.7
Flex	516	14,416,900.0
Total Transportation [5]	1,459,966.0	47,475,037.4

[5] - ties to Exhibit 103 Schedule 1 Page 18 of 18, Line 23

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
SHIRLEY BARDES HASSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

I. Introduction

Q. Please state your name and business address.

A. Shirley Bardes Hasson, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as Manager, Regulatory Policy.

Q. What are your responsibilities as Manager, Regulatory Policy?

A. I am responsible for managing regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate regulatory filings before the Commission as well as compliance with Columbia's Rates and Rules for Furnishing Gas Service, known as Tariff Gas Pa. P.U.C. No. 9 ("tariff"), and regulations affecting Natural Gas Distribution Companies ("NGDC") within this Commonwealth. I also monitor cases before the Commission, recommend Company participation and develop comments for filing when warranted.

Q. What is your professional experience with the Company?

A. I have been an employee of Columbia since 1987 when I accepted a position in the Company's customer service department. In 1989, I was promoted to Office Operations Training Instructor where I provided customer service and compliance training to telephone representatives and field service technicians. My customer

service and training experience required comprehensive knowledge of Chapters 56 (Standards and Billing Practices for Residential Utility Service), 59 (Gas Service), 60 (Natural Gas Transportation Service) and 62 (Natural Gas Supply Customer Choice) of Title 52 of the Pennsylvania Code as well as Columbia's tariff. From 1995 until 2003, I held various positions working with the CHOICE®[1] program and large commercial and industrial transportation, initially as a Distribution Gas Transportation Coordinator, and progressing to Manager, Gas Transportation in 2001. I was significantly involved in the original development, expansion, and modification of the Columbia Choice program ("Choice Program"). I managed employees who provided billing, collections and customer service to Columbia's largest commercial and industrial distribution service customers, and I acted as liaison between the Natural Gas Suppliers and the Company. In 2004, I joined the Regulatory Department as Manager, Regulatory Policy.

Q. Have you testified before this or any other Commission?

A. Yes, I have provided testimony before this Commission in several formal customer complaint cases and in Columbia's last four base rate cases at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748 and R-2014-2406274. I have also testified before the Maryland Public Service Commission on several occasions on behalf of Columbia Gas of Maryland, Inc.

[1] Customer CHOICE℠ is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Pennsylvania, Inc. CHOICE® is a registered mark of Columbia Gas of Ohio, Inc. and its use has also been licensed by Columbia Gas of Pennsylvania, Inc.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit No. 14 Schedule 1 – the list of reports, data or statements requested by and submitted to the Commission, submitted in compliance with Section 53.53 III.A.26, and Exhibits 14 and 114 Schedule 2, which are copies of the tariff that is currently in effect, and the Company's proposed changes to those tariff pages.

Q. Please explain the scope of your testimony.

A. I will review the tariff revisions proposed in tariff Supplement No. 226 and provide detail behind the proposal of a new service provision.

II. Tariff Changes Summary

Q. Please provide a brief description of the tariff changes that the Company is proposing.

A. The non-substantive tariff changes include corrections and additions to the Table of Contents, a spelling correction on page 9, Description of Territory, and other non-substantive formatting changes.

Q. What are the substantive tariff changes?

A. Substantive tariff changes include changes to the rates on pages 16-21c, 160 and 161. Revisions are also proposed to: Rule 5. Testing and Inspecting of Customer's Installations; Rule 8. Extensions; and the Rider Universal Service Plan ("Rider USP").

Q. Are there any new Riders or tariff provisions added to the tariff?

A. Yes. The Rider CAC – Choice Administration Charge is once again proposed in the tariff and Rule 21. Flexible Service Provisions is new to the tariff.

Q. Is there a summary of all the tariff changes available?

A. Yes. Tariff Pages 2, 2a and 2b reflect a List of Changes proposed to the Tariff in this base rate case.

III. Non-Substantive Tariff Changes

Q. Begin with the Table of Contents and describe the changes there.

A. Page 3 reflects the addition of Rule 21. Flexible Service Provisions on page 70. On page 4, the labeling and page number references were corrected for Electric Generation Distribution Service and Cogeneration Distribution Service and Rider CAC has been added.

Q. What spelling error has been identified and corrected in the Description of Territory?

A. On page 9, under Lawrence County, "Neshannock" was incorrectly spelled "Meshannock". The remaining non-substantive changes are related to formatting.

IV. Substantive Tariff Changes

Q. What substantive changes appear on pages 16 through 21c?

A. Pages 16 through 20 are the Rate Summary Pages of the tariff. Changes to the customer charges, distribution charges and pass-through charges for each rate schedule appear on pages 16 through 19. Page 20 reflects a change to the Price to Compare.

The Rider Summary on Page 21 reflects changes in the Rider Customer Choice ("Rider CC"), Rider USP, the Gas Procurement Charge Rider ("Rider GPC"), the Merchant Function Charge Rider ("Rider MFC") and the new Choice Administration Charge Rider ("Rider CAC").

Page 21a details the components of the Gas Supply Charge, which includes the Rider GPC and the Rider MFC rate changes.

The Pass-through Charge Summary on page 21b reflects the increase in Rider CC and Rider USP in addition to the newly proposed Rider CAC.

Page 21c details the components of the Price-to-Compare. Since the Rider GPC and Rider MFC both impact the calculation of the Price-to-Compare, the changes to those two Riders are also reflected on this page.

Q. What are the rate changes on Tariff Page Nos. 160 and 161.

A. Tariff Page No. 160 reflects the rate change to the Rider GPC Rate. Tariff Page No. 161 reflects changes to the uncollectible percentages for the Rider MFC.

Q. Moving on to Rule 5. Testing and Inspecting of Customer's Installations – what is changing?

A. One slight change to this Rule is reflected on Page 42 in the title of paragraph 5.2. The Company is proposing to change the title from "Company's Right to Inspect New Customer Service Lines" to "Company's Right to Inspect Customer Service Lines." The Company is removing the word "New" in order to make the heading

consistent with the tariff language, which states that Columbia has the right to inspect a new installation before service is introduced "or at any later time."

Q. What is the Company proposing in Rule 8. Extensions?

A. On Page 48, paragraph 8.1 Service Connections the Company proposes to install one-hundred fifty (150) feet of service line for new applicants without charge to the applicant. Paragraph 8.2 Capital Expenditure Policy proposes that the Company will install a main line extension up to one-hundred fifty (150) feet per applicant at no cost to the applicant(s).

Q. What is the basis for these tariff changes?

A. In Columbia Statement No. 14, Company witness Waruszewski provides detailed testimony regarding these tariff changes.

Q. What are the proposed changes to Rider USP?

A. The Company is proposing to add the Emergency Repair Program and the administration costs of the CAP application to the calculation of Rider USP.

Q. Please detail the reasoning behind these changes.

A. Company witness Krajovic, in Columbia Statement No. 12, discusses the reasoning behind the changes to the calculation of Rider USP.

Q. Is Rider CAC – Choice Administration Charge being proposed again?

A. Yes, the Company proposed this Rider in its last case at Docket R-2014-2406274, but withdrew the proposal for purposes of settlement. Tariff Page 164 reflects the addition of Rider CAC.

Q. Please provide detail describing this Rider.

A. Rider CAC is detailed in Columbia Statement No. 12, which is Company witness Krajovic's testimony.

V. Flexible Service Provisions

Q. Please explain new Rule 21, Flexible Service Provisions.

A. Rule 21 – Flexible Service Provisions has been added to Tariff Page No. 70 to provide the Company with the flexibility to offer service to eligible non-residential Applicants and Customers that request new or expanded gas service but are located in an area of the Company's distribution system that is, or is expected to become, incapable of serving the Applicant's or Customer's total requirements for distribution service on a year round basis.

Q. What prompted Columbia to develop Rule 21?

A. The Company has been approached by an existing non-residential customer that currently uses natural gas for its offices. However, the Customer has expressed an interest in converting its processing plant, which currently uses oil, to natural gas. This Customer's processing facility is located in an area of the Company's system with capacity limitations and under the existing tariff the Customer would have to make a significant financial contribution to upgrade the main line to eliminate the capacity limitation. Absent the upgrade to the main line, Columbia would have to reject the Customer's request for service for their increased load. Through

discussions with this Customer, the Company identified that the Customer does not operate its processing plant year round.

Q. Are there other considerations for the Company proposing the Flexible Service Provisions?

A. Yes. Rule 21 will provide Columbia with another means to attract new or provide expanded service to existing non-residential customers who would otherwise use alternative fuels or relocate their facilities. Specifically, the Flexible Service Provisions will allow Columbia to provide limited distribution service to those new or existing customers, who will not be impacted by the Company's ability to provide limited distribution service. The Company's current tariff requires it to provide distribution service to any customer on its system 365 days of the year, absent an Emergency[2]. The Flexible Service Provisions enable the Company, at its sole discretion, to enter into an agreement with an eligible Applicant or Customer to provide limited distribution service, including the flexibility to provide distribution service less than 365 days of the year.

Q. Which customer classes are eligible to receive service under the Flexible Service Provisions?

A. Non-residential Applicants or existing non-residential Customers who wish to increase their usage, and who qualify for Rate Schedules SDS, LDS, MLDS, LGSS or MLSS by using more than 64,400 therms annually.

[2] As specified in Rule 2. Service Limitations.

Q. Are there other qualification requirements associated with the Flexible Service Provisions?

A. Yes. As I noted above, the Applicant or existing Customer's facility must be located on a portion of the Company's system where there are capacity limitations. Additionally, the Applicant or existing Customer must enter into an agreement with the Company specifying the service limitations and any other terms associated with providing service including when the Company will not provide total distribution service requirements in the individual customer's circumstance.

Q. Under the current tariff what options does the Company have when it receives a request for service in an area with capacity limitations?

A. As specified in the current tariff, Paragraph 3.2 Right to Reject, the Company may reject applications *"(b) If the Company does not have adequate facilities to render the service desired"*, or the Company could require the Applicant/existing Customer to make a financial contribution to cover the costs of increasing the main line to a size that would eliminate the Company's capacity limitations in that segment of the system in order to serve the Applicant or customer's new load. Of course, the Applicant or customer has the ability to refuse the financial contribution and forego using the Company for distribution service.

Q. What would the Company consider before entering into an agreement under the Flexible Service Provisions?

A. The most important Company consideration is maintaining safe, reliable service to its existing customers and their existing load. Therefore, before entering into an agreement under the Flexible Service Provisions, the Company will carefully consider its available capacity to ensure that providing distribution service under the Flexible Service Provisions to each eligible Applicant or eligible existing customer will not impact the distribution service currently provided to the existing customers and their existing load on that portion of the Company's system.

Q. Once served under this provision will the Customer be served under this provision indefinitely?

A. Potentially, however, the agreement may be terminated if, during the term of the agreement, the Company increases its main line capacity to a level that accommodates the Customer's total requirements for distribution service.

Q. What rates will Customers pay when receiving service subject to the Rule 21?

A. As specified in paragraph 21.3 Rate on Tariff page 70, the Customer will pay the rates specified or negotiated under the applicable rate schedule.

Q. In what circumstance would the rate be negotiated?

A. The rate would only be negotiated if the Customer met the requirements to qualify for Rule 20. Flexible Rate Provisions.

Q. So is it possible that a Customer could be served under Rule 20 Flexible Rate Provisions and Rule 21 Flexible Service Provisions?

A. Yes.

Q. What is the Company's incentive for adding the Flexible Service Provisions?

A. The Flexible Service Provisions would provide the Company with the opportunity to increase load on its system at no cost to the Company, its customers, or the Applicant or existing customer who is requesting distribution service for additional load. As evidenced by the Rider New Area Service proposed by the Company and approved by the Commission in Docket No. R-2014-2407345, and the changes to "Rule 8. Extensions" proposed in this base rate case by Company witness Waruszewski, the Company is continually seeking opportunities to extend access to natural gas for Applicants or existing customers who want to increase their natural gas load. The Flexible Service Provisions are simply one more way to extend natural gas distribution service in the Company's territory.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
ROBERT C. WARUSZEWSKI
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Introduction

Q. Please state your name and business address.

A. Robert C. Waruszewski, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as Senior Regulatory Analyst.

Q. What are your responsibilities as Senior Regulatory Analyst?

A. I assist in the coordination and supervision of regulatory activity before the Pennsylvania Public Utility Commission ("Commission"), including rates and tariffs.

Q. What is your educational and professional background?

A. I graduated in 2011 from St. Vincent College, Latrobe, Pennsylvania where I majored in both mathematics and economics. After graduation, I worked as a junior accounting clerk for the Bank of New York Mellon, assisting in the preparation of audits as well as gathering local tax data for the company's employees before joining Columbia in November of 2011 in the Regulatory department. In November of 2013, I was promoted to my current role of Senior Regulatory Analyst.

Q. Have you testified before this or any other Commission?

A. No I have not testified before this Commission. However, I have testified before the Public Service Commission of Maryland on several occasions.

Q. Please describe the scope of your testimony in this proceeding.

A. I am presenting and describing several new proposals designed to expand the availability of natural gas service in Columbia's service territory.

Q. Please describe the Company's current line extension policy.

A. When a potential customer requests Columbia to extend its facilities, the Company uses an economic analysis to determine the cost of serving that customer, as described in section 8.2 of its tariff. This analysis compares the net present value ("NPV") of the projected future revenue, for that customer, to the cost to add the customer. If the result is positive, that is, the projected customer revenues are greater than or equal to the projected cost, then the Company will make the line extension without cost to the customer. However if the result is negative, that is, projected costs are greater than projected revenues, Columbia requires the customer to pay a deposit for service. The deposit amount is the amount required to make the analysis whole. This same approach is used if Columbia is approached by multiple potential customers to be served off a single extension of facilities.

Q. Please explain the Company's New Area Service Rider.

For residential customers that do not have the ability to pay the deposit up-front, the Company currently offers a pilot New Area Service Rider ("NAS"). NAS allows the customer to pay the full or partial amount of the deposit over a period of 20 years on their monthly bills.

Q. Since NAS is intended to provide an option to enable more potential customers to elect natural gas service, why is the Company offering additional growth options at this time?

A. One of the largest barriers for customers to convert to natural gas is the up-front deposit. While Rider NAS reduces this barrier by spreading the cost of the deposit over a period of time, it does not reduce the overall cost a customer must bear to have the Company extend its facilities to serve them nor does it assist the customer in the upfront costs of installing piping at their home for their natural gas appliances. Given the abundant supply of low-cost gas from Marcellus Shale in Pennsylvania, now is an excellent time to make it easier for applicants to convert to natural gas and enjoy the cost savings of this efficient natural resource.

Q. What does the Company propose to reduce customers' upfront cost to convert to natural gas?

To help more Pennsylvanians enjoy the benefits of natural gas, Columbia has developed three incentives that, alone and in combination with NAS, will further encourage more customers to elect natural gas service: (1) footage allowance of 150 feet of main line per applicant without the need for a NPV analysis in normal situations, (2) an allowance of 150 feet of service line in normal situations for customers served in those portions of Columbia's service territory where the Company owns the service line and (3) reimbursement of up to $1,000 for the

installation of house piping on projects when projected revenues exceed projected costs by a certain threshold.

Q. Has Columbia received encouragement to do more to expand the availability of natural gas service?

A. Yes, on page 19 of her direct testimony in the 2012 Columbia Gas of Pennsylvania Rate Case, Docket R-2012-2321748, I&E's Witness Lisa Boyd, while commenting on the Company's original Pilot Rider NAS proposal, suggested "that an incentive offer would be appropriate, either a specified free extension distance or a starting cash credit towards the cost of the extension project." On page 11 of his Rebuttal Testimony, Columbia's Witness, Erich Evans, stated that "Columbia is not opposed to the idea of an incentive offer, as long as the Company can recover the cost of the incentives." Furthermore, in the 2014 Pilot Rider NAS Proceeding – R-2014-2407345, OCA's Witness Glen Watkins suggested on page 10 of his Direct Testimony that "Mechanisms with a modest sharing of the cost of expansions between new and existing customers should be explored." Also, in a statement issued at the time of the Commission's approval of Columbia's Pilot Rider NAS, Commissioner Witmer observed:

> It is well known that I have been a staunch proponent of innovative programs to encourage the extension of natural gas into underserved and unserved areas of the Commonwealth. Pennsylvania sits on top of one of the largest natural gas reserves in the world. The ability to economically extract Marcellus Shale gas has made Pennsylvania the second largest producer of natural gas in the country. As a result, Pennsylvania consumers, residential and very importantly,

> industrial customers, should have every reasonable opportunity to take advantage of this efficient and clean burning natural resource. I am voting to support Columbia's proposal because it represents an effort to expand natural gas service, however, I am underwhelmed and am of the opinion that it falls short of these goals.
>
> Specifically, upon review of Columbia's proposal and the Order before us today, I find the total funding amounts and the payback parameters of Columbia's pilot Rider NAS to be underwhelming. To that end, as pilot Rider NAS is put into place, I strongly encourage the Company to review these aspects of the program and, when opportunities arise, propose mid-course corrections in order to create a more expansive, dynamic and effective program that can truly encourage the extension of natural gas throughout Columbia's service territory.

Q: In the Pilot Rider NAS proceeding, Columbia opposed proposals to revise the calculation of customers' contributions under the NPV model. Why is Columbia now offering incentives to reduce the customer contribution toward the cost of new construction?

A: There are several reasons. A primary reason is to be responsive to the comments of Commissioner Witmer that Columbia propose more expansive changes to encourage extensions in Columbia's service territory. Further, an allowance approach will reduce the frequency of NPV calculations, thereby being more "consumer friendly" to applicants.

Proposed Main Extension Tariff Change

Q. Does the Company currently offer any footage allowance for customers to connect to Columbia's system?

A. No, the Company does not currently offer customers any mains footage allowance to connect to its natural gas system.

Q. Has the Company ever offered incentives to connect to its system?

A. Yes, as recently as 2001, Columbia offered to extend its system by 65 feet without payment of a customer contribution for any residential customer who would be using natural gas as their heating source.

Q. Why did the Company stop offering this incentive?

A. Columbia's access to capital at that time was severely limited.

Q. Is the Company aware of any NGDCs who offer a footage allowance to residential customers?

A. Yes, Valley Energy offers a combination of up to 200 feet of service and or main extension per customer. In addition, the Company's affiliates in Ohio and Kentucky and other NGDCs such as Delmarva Power (DE), Duke Energy (OH) and Dominion East (OH) are some of the many companies who offer main line extensions without charge to applicants. The Company recently requested the American Gas Association ("AGA") to conduct a survey of natural gas utilities to inquire how many natural gas utilities offer a footage allowance to residential applicants. Of the 23 companies that responded, approximately 60% of companies offer a mains footage allowance to serve new customers.

Q. Please describe the Company's main extension tariff change proposal.

A. Columbia is proposing a tariff change for residential extensions. For each customer that requests a main line extension, Columbia would install the first 150 feet of main line without charge to the customer in normal situations. At the Company's discretion, projects with abnormal underground conditions, such as crossing a stream or state highway, or visible ledge or rock that will affect excavation or excessive permitting fees would not be eligible for the 150 foot allotment. As more applicants join in a single project to extend gas facilities the greater the length of main the Company will install without charge to the applicant. For example, on a single project with 10 customers electing to receive natural gas, the Company will install up to 1500 feet of main line without requiring a customer contribution. For extension projects greater than 150 feet per customer, the Company will run an economic model solely on the line extension segment in excess of the 150 foot allotment per customer to determine if the customer will be required to pay a deposit. For example, if one customer requested a 200 foot line extension, the Company would run the economic analysis on the cost to extend facilities 50 feet to the customer. This deposit may be paid up front or through Rider NAS.

Q. Why did the Company determine 150 feet was the appropriate offer?

A. Please see Exhibit RCW-1. The Company calculated the miles of road and housing units in its service territory and found that there was an average of 136 feet of road per every housing unit. By offering a 150 foot allowance to each applicant, the

Company is providing an allowance equivalent to the average distance of extending its main from one house to the next.

Q. What will be the ratemaking treatment of the allowance?

A. The cost of all facilities installed will be included in rate base in future proceedings, and revenues will be reflected for the new customers added. If further customers are connected to facilities constructed within the allowance, no credit would be provided to the original customers added as part of the extension. If a customer contribution is required, and new customers are later added to the extension, the Company's existing rules regarding provision of a credit under its main extension rules on Rider NAS will continue to apply.

Proposed Service Line Tariff Change

Q. Please explain the ownership of service lines throughout the Company's service territory.

A. As specified in Columbia's tariff, in some areas of the Company's territory the Company owns the service line, primarily in the eastern side of the state, while in other areas, primarily in the western part of the state, the customer owns the service line. I am advised that this distinction is mandated by Section 1510 of the Public Utility Code.

Q. Does the Company currently offer any service line allowance to applicants who wish to connect to the system?

A. No, the Company does not currently offer any service line allowance for customer connections. Pursuant to section 8.1 of Columbia's tariff, the Company installs the service line from its main to the point of delivery. In areas where the Company owns the service line Columbia "will install the service line from its main to a convenient point, approximately fifty (50) feet inside the customer's property line." However, the cost of this service line extension is currently included in the facility extension calculation.

Q. Has the Company ever offered a service line allowance for applicants?

A. To my knowledge, the Company has never offered a service line allowance for applicants.

Q. Is the Company aware of any Pennsylvania NGDCs who offer a service line allowance to residential customers?

A. Besides Valley Energy, which offers a combination of a service line and/or main allowance, Leatherstocking Gas Company and Pike County Light and Power Company respectively offer 100 feet and 50 feet of a service line allowance for buildings that are "designed and used for year-round occupancy." In addition, Columbia Gas of Ohio does not require any contribution toward the cost of a service line to serve new customers. Columbia Gas of Kentucky offers a 100 foot service line allowance for new customers, Columbia Gas of Maryland offers a 50 foot service line allowance per customer and Columbia Gas of Virginia has proposed to offer a 150 foot service line allowance in its current rate case.

Q. Why is the Company proposing this Service Line Change?

A. As I stated earlier in my testimony, Columbia seeks to be responsive to the comments of Commissioner Witmer that Columbia propose further changes to its extension rules to enable more potential applicants to benefit from the availability of low cost natural gas supplies. Besides the cost of extending the Company's main line, the cost of installing a service line is another big deterrent to keep potential applicants from requesting natural gas service. A service line allowance, in addition to the Main Line allowance per applicant, and Pilot Rider NAS, would significantly reduce the cost to potential applicants to elect natural gas.

Q. Who is eligible for this Program?

A. Residential customers in areas where Columbia owns the service line are eligible for this program.

Q. Please describe the Company's Service Line Change Proposal.

A. In areas where the Company owns the service line, new applicants will receive 150 feet of service line allowance in normal situations. In cases of abnormal underground conditions, such as crossing a stream or state highway, or visible ledge or rock that will affect excavation or excessive permitting fees the customer would be required to pay a contribution for the cost for the service line. In cases where the service line extension would be greater than 150 feet, the customer may be required to pay a deposit. The Company will run the economic analysis only on the main and service line portions that exceed the 150 feet threshold to determine if a deposit is

required. This deposit may be paid up front or through Rider NAS. For ratemaking purposes, the entire cost of the service line extension, net of any contribution, will be included in rate base.

Q. Why did the Company determine 150 feet was the appropriate offer?

A. Based upon the Company's experience, if there is a Company main on the street, 150 feet of service line is normally sufficient to connect most customers to the Company's main.

Proposed House Line Reimbursement

Q. Please explain the Company's house pipe proposal.

A. As stated earlier, the Company runs an economic analysis for customers who request a main line extension. For projects where the economic analysis result is positive by at least $1,000 per customer, the Company proposes to reimburse customers for a portion of the cost of the installation of house piping, up to $1,000. For example, if the economic analysis of a project of 10 residential customers yields a positive result of $10,000, the Company would reimburse each of the customers up to $1,000 for the installation of house piping. Customers would pay for the work to be done in their homes and then would provide the Company documentation that the work had been done in order to obtain reimbursement from the Company.

Q. Will the cost of the 150 feet of main and service line be included in the economic analysis to determine if the customer is eligible for a house piping reimbursement?

A. Yes, even though the Company will extend its main 150 feet and install 150 feet of service line, in areas where the Company owns the service line, at its own expense, these costs will be placed in the economic model when determining if the customer is eligible for a house piping reimbursement, so that existing customers do not subsidize new customers for house piping.

Q. Which customers would be eligible for this program?

A. Only residential customers converting to natural gas would be eligible for this program. New homes would not be eligible for this program.

Q. Why should the Company offer reimbursement for the installation of house piping in a customer's home?

A. The cost of installing the house piping and new appliances can cost a customer thousands of dollars. Even with the main line and service line allowances, this additional cost may be a significant enough deterrent to dissuade people from converting to natural gas. For projects that would generate a net positive present value greater than $1,000 per customer, the Company can offer assistance to help cover the customer's house piping costs to ensure the line extension does take place.

Q. Won't existing customers be subsidizing new customers on the house piping proposal?

A. No, as stated, Columbia will never reimburse a customer enough to cause the project to return a negative result. Since the reimbursement can only go as high as the positive result of the project, existing customers will not be subsidizing the costs

of new customers' piping. Let us consider two scenarios in which customers would like to convert to natural gas, but without the assistance of the Company for house piping installation, the projects would not go through.

Scenario	Economic Analysis Result	House Line Installation Costs	Net Result
1	$10,000	$10,000	$0
2	$10,000	$5,000	$5,000

For example, consider scenario 1, a project with a positive result of $10,000. If the Company paid the full amount of $10,000 to assist customers in installation of house piping, the net result for the project would be $0. The economic model guides the Company to make the investment of main extension for any project with a result greater than or equal to $0. So in this case, the project is still economically justified by the Company even with the Company's contributions to house line installations. To put it another way, the rates the customer will pay will fully cover the investment to add this customer. Therefore, the effect to existing customers is the same as if a project with an economic analysis result of $0 was built for customers without any money given in contribution to house piping. The upside for existing customers is in Scenario 2. In this project with an initial result of $10,000 the Company reimburses the $5,000 cost to install house piping. The net result is a $5,000 benefit to existing

customers from the new customers being added onto the system, since the projected revenues reduce the overall cost of maintaining the system.

Q. How will the Company record for ratemaking purposes, the cost of reimbursing for house piping?

A. The Company will record the cost of reimbursing house piping as an O&M expense.

Q. Will the three new proposals replace the use of the Company's Pilot Rider NAS?

A. No, these proposals will be used in conjunction with NAS and will increase the scope and effectiveness of NAS.

Q. Please summarize your tariff change proposals.

A. The Company proposes to extend its main 150 feet without charge to an applicant for each applicant that applies for a line extension. Secondly, in the areas where the Company owns the service line, Columbia proposes to install 150 feet of service line for new applicants without charge to the applicant. Finally, for projects that have a positive economic analysis greater than $1,000 per customer, the Company proposes to reimburse customers up to $1,000 for the installation of house piping. In this way, the Company is addressing three major barriers applicants face when they wish to select natural gas as their heating source, the cost of main line extensions, the cost of service line installations and the cost of house line installations. By reducing these upfront costs, the Company will make it easier for applicants to select natural gas service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

County:	Adams	Allegheny	Armstrong	Beaver	Bedford	Butler	Centre	Chester	Clarion	Clearfield	Elk	Fayette	Franklin	Fulton	Greene	Indiana	Jefferson	Lawrence	Mckean	Mercer	Somerset	Venango	Washington	Westmoreland	York	Total CPA Counties
Number of housing units	41041	587831	32278	78091	23894	78930	64283	194329	19801	38415	17469	62500	63762	7071	16349	38296	22323	40647	20995	51421	37809	27197	93954	167673	179599	2005358
Road miles																										
Penndot	543.55	1178.07	655.27	603.58	794.78	653.6	585.77	1017.52	469.04	795.26	294.23	756.7	613.54	342.32	573.86	797.18	555.42	385.01	381.69	740.77	880.95	528.75	1090.7	1186.66	1134.54	17560.76
Other	31.06	1	14.1	23.6	33.8	38.68	27.85	17.8	12.86	22.64	111.34	13.32	12.33	3.4	4.92	31.66	4.16	1.6	158.35	31.65	24.47	9.75	1.78	24.12	13.49	669.75
Turnpike																										
Toll bridge																										
Local	831.38	4623.24	1150.29	1039.12	917.66	1608.22	894.81	2558.23	945.59	1141.82	374.72	1303.06	1048.57	321.95	931.11	1270.98	841.03	794.47	481.14	1263.09	1267.04	826.54	1753.75	2400.52	2648.89	33237.22
Total Road Miles	1405.99	5802.31	1819.66	1666.3	1746.24	2300.5	1508.43	3593.55	1427.49	1959.72	780.29	2075.08	1674.44	667.67	1509.89	2099.82	1400.61	1181.08	1021.18	2035.51	2172.46	1365.04	2846.23	3611.3	3796.92	51467.71
# housing units per mile	29.1901	101.3098	17.7385	46.8649	13.6831	34.3099	42.6158	54.0772	13.8712	19.6023	22.3878	30.1193	38.0796	10.5906	10.8279	18.2378	15.9381	34.4151	20.5595	25.2620	17.4038	19.9240	32.7992	46.4301	47.3012	38.9634
Road per home	181	52	298	113	386	154	124	98	381	269	236	175	139	499	488	290	331	158	257	209	303	265	161	114	112	196

COLUMBIA STATEMENT NO. 15

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2015-2468056
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MICHAEL J. DAVIDSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 19, 2015

Table of Contents

I. Introduction 1

II. Overview of Columbia's Pipeline Distribution System 3

III. Columbia's Pipeline Replacement Efforts 11

IV. Federal Pipeline Safety Rules and Advisories 26

V. Strategic O&M Initiatives 32

VI. Columbia's Operating Performance 40

I. Introduction

Q. Please state your name and business address.

A. Michael J. Davidson, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as General Manager and Vice President.

Q. What are your responsibilities as General Manager and Vice President?

A. My responsibilities include overseeing:

- Delivery of safe and reliable gas distribution service to our customers;
- Leak detection, leak investigation, leak response and leak repair activities;
- Customer metering activities;
- Plant operations and system regulation;
- All required leakage surveys and system inspections, testing and inspection of cathodic protection systems for steel facilities, and performing underground facilities locating for third-party excavators;
- The day-to-day operations of Columbia's physical gas piping system; and
- Field customer service to Columbia customers including: odor complaints, pilot light-ups, meter turn-ons and turn offs, and all other customer interfacing field interactions.

Q. What is your educational background and professional experience?

A. I graduated from Pennsylvania State University, earning an Associate Degree in Electrical Engineering Technology. Following nearly five years of service in the United States Air Force, I attended Point Park College, earning a Bachelor's Degree in Electrical Engineering Technology and then earned a Master's Degree in Public Management from Carnegie Mellon University. I have also earned a Six Sigma Black Belt certification from the University of Michigan College Of Engineering. Following my military service, I joined Equitable Gas as a Communications Specialist. My primary job duties were the installation and maintenance of pipeline SCADA systems, electronic measurement equipment and microwave communication systems (1991-1996). I then joined Columbia Gas in 1996 and have held a number of management roles of increasing responsibility. Functional areas that I have had the opportunity to lead include: operations planning, business improvement, applications support, integration center (operations workforce management), meter to cash, and customer contact centers.

Q. Have you testified before this or any other Commission?

A. No.

Q. Please describe your membership in, or affiliation with, any industry organizations.

A. My industry affiliations include: Membership in the American Gas Association, Southern Gas Association and the Energy Association of Pennsylvania.

Q. What is the purpose of your testimony?

A. I will provide an overview of Columbia's distribution system, and discuss Columbia's ongoing replacement activities and provide testimony in support of Columbia's plant additions through the Fully Forecasted Future Rate Year (twelve-months ending December 31, 2016). I will also discuss Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations.

Finally I will testify regarding Columbia's Distribution Integrity Management Program Plan ("DIMP Plan"), the strategic O&M activities that it has undertaken to improve its system, and the additional O&M activities that it is planning to undertake beginning in 2015.

II. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves more than 419,000 residential, industrial and government customers. The Company owns and operates a natural gas distribution system in 26 counties serving 450 communities in Pennsylvania. Columbia provides that service through approximately 7,443 miles of mains and approximately 420,733 services that it owns, operates, and maintains.[1] These facilities (as of

[1] I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the

January 1, 2015) are composed of approximately 1,504 miles of bare steel, 25 miles of cathodically protected bare steel, 34 miles of cast iron, 94 miles of wrought iron mains (in total, 1,657 miles of "first generation" main), and 56,766 bare steel services.[2] The balance of the system is comprised of cathodically protected coated steel, or plastic (polyethylene) mains and services, and 39.6 miles classified as other.[3]

Columbia's distribution infrastructure constitutes the final step in the delivery of natural gas to customers from the producing regions of the Southern United States, Western Canada, and in-state Pennsylvania-produced Marcellus supplies. Columbia distributes natural gas by taking it from delivery points (or "city gates") along interstate pipelines, then transporting it through relatively small-diameter distribution mains and services that network underground through cities, towns, and neighborhoods in order to meet the demands of end-use customers. After taking delivery of natural gas at the city gate, Columbia then steps down the transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Columbia's system, and then in

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service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

[2] The terms "bare steel," "unprotected coated steel," "unprotected steel," and "wrought iron" as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

[3] It should be noted that in 2011 Columbia deployed a Geographical Information System ("GIS") Mapping System to provide both mapping and data retrieval capabilities on its system and facilities. The 39.6 miles of "other" main appear to be anomalies in the data conversion and through a scrubbing process have been reduced from over 43 miles in 2013.

some cases increases the amount of odorant known as mercaptan (the "rotten egg smell") to the natural gas before it is put into the distribution system. The gas then goes into the Columbia distribution system where the pressure is often further reduced to delivery pressure in a series of district regulator stations, before being delivered to each customer. Once the gas is delivered on the customer's side of the meter (or the property line in Western Pennsylvania), it is owned by the customer and becomes the responsibility of the customer. In sum, Columbia's distribution system moves relatively small volumes of natural gas at lower pressures over shorter distances to a far greater number of individual users than its interstate pipeline counterparts.

Q. Please describe the years, types, and operating characteristics of the various pipe materials that have historically been installed in Columbia's system.

A. The system is comprised of many different types of pipe. From the 1850s to the early 1900s, Columbia's predecessor companies installed cast iron pipe throughout the early distribution systems. Cast iron, wrought iron and wood were among the first materials available, and cast iron had the advantage in that it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. When the pipe was buried to typical depths of between two and five feet, if the soil beneath the pipe or to its side was disturbed and pressure exerted on the pipe, it could crack. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, it was determined that it was unsuitable for long-

distance transportation of gas because it was unable to withstand high pressures.

Q. How did the industry react to the problems present with the use of cast iron?

A. By the early 1900s, the industry had adopted steel and wrought iron piping for mains. These were deemed to be stronger than cast iron and able to withstand greater pressure. During this time, bare steel and wrought iron began replacing cast iron pipe as the material of choice when building a natural gas distribution system. During the pre- and post-World War II construction boom, gas utilities like Columbia, along with developers and customers, installed a significant amount of bare steel mains and services. Bare steel is steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. The use of bare steel and wrought iron was common until the 1950s and 1960s when the industry began to realize that, despite its strength, bare steel was subject to corrosion and, in order to increase long-term safety and reliability, coating and cathodic protection should be applied to all new piping systems. Both exterior coatings and cathodic protection were designed to inhibit corrosion. Columbia installed its last bare steel pipe in the 1960s. By 1970, the federal government prohibited the installation of bare steel for natural gas distribution system infrastructure.

Q. What did the industry do to combat the problem of corrosion in bare steel?

A. The fact is that all metals corrode as a result of the natural process of chemical interactions with their physical environment, most commonly caused by moist soil (which creates an electrolyte) around the pipe, causing corrosion. In these

circumstances, direct electric current flows from the metal surface into the electrolyte and, as the metal ions leave the surface of the pipe, corrosion takes place. This current flows in the electrolyte to the site where oxygen or water is being reduced. This site is referred to as the cathode or cathodic site. In order to combat corrosion, natural gas distribution companies ("NGDCs") began using coated steel. Unprotected coated steel ("UPCS" or "coated steel") refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil).

Q. Did the use of UPCS solve the problem?

A. No, despite the best efforts of industry, and even though it was for a time an accepted industry standard, UPCS corroded as well. But for the period from the 1940s through the 1960s, as the industry assessed its options, it was one of just a few alternative piping materials available to meet the public demand for service. By 1970, Columbia had laid its last non-cathodically protected coated steel segment. Further, since that time Columbia has retrofitted all of its unprotected coated steel facilities with cathodic protection systems.

Q. What materials replaced bare steel and coated steel?

A. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. The pipe breakthrough for the natural gas industry came in the mid-1960s with the introduction of plastic (polyethylene) pipe for gas distribution applications.

Q. What is "cathodic protection?"

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion and deterioration (i.e., rusting and pitting) by applying an electrical current to the pipe. Cathodic protection reduces corrosion by making that surface the cathode and another metal the anode of an electrochemical cell. A primary function of a coating on a cathodically protected pipe is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal. At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection.

Q. Has Columbia further improved the functionality of its piping since the introduction of cathodically protected steel?

A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, it is more costly to purchase and install, and requires more ongoing maintenance than the next generation pipe – plastic.

Q. What are the benefits of plastic pipe?

A. Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. Plastic does not corrode and, therefore, does not require cathodic

protection.

Q. Does plastic pipe have any drawbacks?

A. The two significant drawbacks to plastic are:

- Relative vulnerability to excavation damage as compared to cast iron or steel. As a result, excavators who do not dig by hand (despite being required to do so by One-Call laws) in the vicinity of plastic facilities are very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are somewhat more likely to be able to resist external impact.
- "First Generation" plastic pipe, typically installed between 1970 and 1981 in most distribution systems and softer than today's "418 PE" material (due to the different composition of the base plastic material), has demonstrated itself to be prone to stress propagation cracking under some circumstances. Thus in certain limited cases, Columbia's first generation plastic pipe has generated Type-1 leaks due to significant longitudinal cracking along the pipe.

Q. What is Columbia doing to address these concerns?

A. Columbia has made significant progress in reducing facility damage rates. In 2007, damages per thousand locates were at 5.39. In 2014, damages per thousand were at 2.65 per thousand. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven to be effective.

However, overall damage prevention rates, while improved from historical levels, have plateaued over the last three years. Contractor negligence remains the highest cause of damages to our system and has increased from 47% of total damages in 2010, to nearly 61% of total damages in 2014. In an effort to further reduce damages in this area, Columbia has added four damage prevention coordinators to expand contractor outreach efforts. Columbia is continuing the practice of using "marker balls" when installing its new plastic facilities. These marker balls are placed in the ground above the pipe after it has been installed and enable Columbia to locate it later using electronic technology. Columbia is also deploying GPS mapping and locating technology that provides sub-decimeter accuracy in identifying the location of new or replacement facilities. This breakthrough technology will enable the Company to accurately locate its new facilities in the field. This will provide facility locators with a highly accurate, state-of-the-art ability to find facilities anywhere in the system that have been captured using this new technology. Thus, it has the clear potential to revolutionize our One-Call response procedures and the overall quality of facility locating. Columbia's plan is to capture all new and replacement installations using this new methodology, and simultaneously and systematically begin to capture existing system main and service information across the existing Columbia system, until we have captured detailed and accurate data on the entire system.

In order to address the issue that the industry has identified as "First Generation"

plastic pipe, Columbia is replacing those sections of first generation pipe that are uncovered in the course of executing the bare steel and cast iron program. Further, depending on future failure rates of this first generation plastic pipe, and the relationship between those failure rates and other risks in the Columbia system at the time, Columbia's annual DIMP Plan risk evaluation may determine at some point in the future that a systematic program will be needed to replace the remainder of this softer, more vulnerable, first generation plastic material.

III. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel and cast iron main has been eliminated from the Columbia system during its accelerated program, and how does that trend compare with the previous years?

A. Columbia began an accelerated replacement of bare steel and cast iron pipe in 2007. Between 2007 and 2015 Columbia has retired, or projects to retire, the following footages of bare steel, wrought iron, and cast iron by year:

2007	355,764 feet
2008	528,567 feet
2009	344,488 feet
2010	322,583 feet
2011	533,765 feet
2012	467,808 feet

2013	449,856 feet	
2014	413,667 feet	
2015	402,109 feet (projected)	
Total Actual	**(Through YE 2014)**	**3,416,498 feet**

From 2007 through 2014, the program has eliminated an average of 427,062 feet per year. During the 4 years from 2002 to 2005 the average annual rate of retirement was 196,948 feet, less than half the rate of retired footages of bare steel, wrought iron, and cast iron under the current program.

Q. How have replacement costs trended and what are the primary cost drivers?

A. Columbia has experienced upward cost pressure for replacement projects over the past six years. The average cost of main replacement in 2008 was $81.25 per foot, while the average cost of main replacement in 2013 (the last full year that data is available) was $151.62, an increase of nearly 87%. There are several factors creating the upward cost pressure:

- The location of projects has a significant impact on cost. Hard surface projects in urban areas normally have a higher replacement cost per foot than soft surface replacement in rural areas, given similar size and material of pipe are being installed. The increased cost of urban areas can be due in part to the need to coordinate replacement of Columbia's facilities with facilities of other utilities or municipalities. These higher cost urban areas

often have higher risk and are increasingly being prioritized for replacement, contributing to the increasing average cost per foot.

- Changes in hard surface restoration requirements are a key component of the upward cost pressures being experienced. Municipalities are expanding restoration requirements on utilities. For example, six years ago it was typical that trench restoration would consist of simply paving the trench that was excavated for the main installation. Today that same project frequently requires curb to curb milling and overlay. On other projects, Columbia is required to locate its facilities under sidewalks rather than in the street where mains were historically located. On these projects, Columbia is required to replace the entire sidewalk, and to the extent that the sidewalk does not meet ADA (Americans with Disabilities Act) standards, Columbia is required to make them compliant with current standards. This can include wheelchair ramps and curb realignment or replacement work.
- Contractor cost is another key component of increased cost. Contractor cost increases have been driven by competition for resources as more natural gas local distribution companies in Pennsylvania and across the country undertake main replacement programs.
- The mix of plastic and steel mains and the diameter of the mains needed in the Company's system also can affect the average main replacement cost. The large, geographically dispersed nature of Columbia's system requires it

to have a relatively high number of higher pressure steel, larger diameter mains to carry gas across the very broad western and eastern Pennsylvania service territories that Columbia serves. As a result, far more of the facilities being replaced have to be designed and constructed of larger diameter pipe, with a larger percentage of steel (vs. lower cost plastic mains), compared to utilities that have smaller, more geographically compact service footprints. In fact, and by way of comparison, in 2012 Columbia had the largest average main diameter among all of the NiSource Gas Distribution Segment LDCs, and its installation of steel replacement mains (vs. Plastic mains) is also well above the NiSource Gas Distribution Segment average.

These combined factors have driven the unit cost for the Company's main replacements to increase materially over the last six years. This has necessitated greater capital spending by Columbia to keep pace with the program's retirement footage objectives.

Q. What is Columbia doing to manage cost increases?

A. Columbia is focused on managing costs and making prudent capital investments that benefit our customers. Columbia Gas of Pennsylvania is one of seven distribution companies in the NiSource family making infrastructure capital investments. This enables NiSource to negotiate at scale with contractors and suppliers, delivering competitive pricing for materials and services provided to Columbia Gas of Pennsylvania.

Columbia Gas of Pennsylvania continues to work with local governments in an effort to maintain reasonable permitting and restoration requirements for pipeline replacement projects. Our goal is to balance the requirements of local governments while delivering the best value for our customers.

Columbia Gas continues to engage local governments in an effort to maintain that balance. The following are some recent examples:

- Negotiated with the Redevelopment Authority of Washington County to obtain an easement on property they own for a needed pipeline replacement project. Cost was reduced from $50,000 to a fair market value of $20,000.
- The City of Pittsburgh's proposed a "Major Street Opening Permit" revision that would have increased costs and possibly delayed pipeline replacement projects in the City. Columbia Gas, working with the other utilities, was able to amend the bill so that it does not apply to utility infrastructure work.
- Working with the City of Washington, restoration costs were reduced by $70,000 in a one year period. The City has agreed that an ordinance requiring two police offers to provide pedestrian and vehicle safety on all pipeline replacement projects should only be enforced on major roads, not side streets with sparse vehicle and pedestrian traffic.

- Columbia continues to negotiate with the City of Pittsburgh on a final restoration plan for Dellrose Street. The City is asking Columbia to install water catch basins on the brick street at an estimated cost of $750,000.

Q. How does Columbia install pipe in its underground distribution system?

A. The initial installation of natural gas distribution pipe requires the excavation of a trench usually under or adjacent to a public street into which the pipe is laid. Then new or existing customer services are connected to the new main.

Installation of natural gas distribution pipe can be a major inconvenience for residents, business owners and municipalities. In some circumstances, where smaller diameter plastic facilities are installed to replace larger diameter steel piping, the cost and inconvenience associated with excavating a trench can be reduced by inserting the new pipe through the old piping. This involves smaller street cuts for the insertion plus smaller cuts associated with service line and intersecting main tie-ins. Further, even if a replacement main must be laid rather than inserted, the use of smaller plastic pipe, where viable, rather than larger steel or cast iron pipe will produce a savings in material costs.

Q. Why does Columbia need to continue to replace its bare steel and cast iron systems?

A. Columbia's Distribution Integrity Management Plan (DIMP) risk scoring continues to rank external corrosion on bare steel and bell joint failure on cast iron pipelines among our top system risks. Corrosion on first generation mains represents nearly 75% of all hazardous or potentially hazardous leakage cleared on mains in the

Columbia distribution system in 2014. Columbia has determined that there are an increasing number of leaks in areas where unprotected steel is concentrated. We believe that the accelerated replacement of the first generation system is not only prudent, but is a requirement under the federal DIMP rule that Columbia continues to address very aggressively in a consistent and programmatic way.

As a result, Columbia plans to maintain or increase its capital expenditures in the 2014 to 2018 timeframe, with a planned spending program ranging between $145 and $170 million budgeted annually for line replacement over the 5-year period. This budget includes the replacement of bare steel, cast iron, and wrought iron pipelines. (Please see the Company's response to Standard Data Request GAS-ROR-014.)

Q. Please explain Columbia's capital additions claimed for the Future Test Year and Fully Forecasted Rate Year.

A. The capital expenditures for the Future Test Year ending November 30, 2015 and the Fully Forecasted Rate Year ending December 31, 2016 are shown in Exhibit 108, Schedule 1. The amounts shown are taken from Columbia's capital budget, as developed by our operations group and engineering department. For a listing of replacement projects being constructed in 2015, please see Exhibit MJD – 1, which is attached to this testimony.

Further, for a detailed description of Columbia's age and condition actuals for 2014, and budgeted amounts for 2015, and 2016, please see the chart below.

Columbia Age & Condition Replacement Budgets ($000)

GPA	Description	Total 2014 Actual	Total 2015 Projected	Total 2016 Projected
354	Compressor Stations	415	250	250
376	Mains - Leakage Elimination	50,597	54051	53,750
380	Service Lines - Replaced	29,543	30500	30,500
376	Customer Servic e Lines Replaced	13,983	12500	12,500
381	Meters / 998 Int. Co. Meters	707	700	700
382	Meter Install - Replace	567	550	550
383	House Regulators - Replace	96	150	150
378	Plant Regulators - Replace	450	750	750
375	Reg Structures Replace	155	150	150
385	LV Excess Press Meas Sta	123	100	100
376	Corrosion Mitigation Ins	147	100	100
376	Large Projects / Specifics/Misc	51,514	44,799	47,500
		148,297	144,600	147,000

(*For greater detail on the total capital spend and the specific allocation breakdowns please see GAS-ROR-014.)

Taken in total, Columbia has made enormous progress since 2006 in delivering and maintaining a safe and reliable distribution system for its customers. The progress that I refer to is defined in more detail throughout this testimony, but includes initiating an annual leakage survey on all of its bare steel mains, identification and mitigation of system cross bores, reducing the number of inactive services in the system, reducing its Type-2 leak repair backlog, improving the locating process to reduce third-party damage, improving emergency response rates and on-time appointments for customers, and dramatically increasing the amount of bare steel

and cast iron pipe that it removes from the system annually. Having said all of that, however, the system data is clear that as first generation bare steel and cast iron pipe continues to age, Columbia will have to continue to focus on the accelerated replacement of bare steel and cast iron to address the problems associated with aging infrastructure. Therefore, it is essential that Columbia continue to direct management effort and incremental capital resources toward this ongoing need. The synchronization of these replacement efforts with the enhanced focus on pipeline safety that Columbia has demonstrated over the last 8 years are integral parts of Columbia's DIMP Plan, and are essential planks of Columbia's ongoing efforts to enhance natural gas pipeline integrity management, and thus provide a safe, reliable distribution system for our customers, and the general public.

Q. How do Columbia's bare steel replacement rates compare with other Pennsylvania NGDCs?

A. Pennsylvania NGDCs' 7100 DOT reports provide data for an analytical comparison of changes in the amount of bare steel pipe in the systems during the years of 2009, 2010, 2011, 2112 and 2013 show the following (in miles):

Bare Steel miles of main from 7100 DOT reports (Note, 2014 data is not yet available for the other Pennsylvania NGDCs)

	Peoples	Equitable	UGI	PECO	Columbia	Nat'l Fuel
2009	1917	781	391	367	1958	1035
2010	1906	762	379	361	1902	999
2011	1884	737	368	355	1751	966
2012	1865	713	392	351	1674	1093

2013	1853	709	376	329	1597	1063
Total Change	64	72	15	38	361	69*
Aver. Per Year	16	18	4	9	90	34*

(*Note: Due to National Fuel's 2012 data, which showed an increase in bare steel inventory, which may be due to a reclassification of assets rather that an addition of bare steel facilities, this assessment uses the 2009 to 2011 period for comparison.) As this chart demonstrates, in the five year period 2009 through 2013, Columbia has replaced nearly five times more bare steel main as the next highest NGDC among its peers in Pennsylvania. To further underscore this, as demonstrated in the chart above, between 2009 and 2013 Columbia has averaged approximately 90 miles of bare steel eliminated per year compared to approximately 34 miles for its next closest peer.

Q. Is there another solution for addressing the issues with bare steel and cast iron short of replacement?

A. No. Corrosion leakage on unprotected steel does not slow down and the rate of leakage will only accelerate as the unprotected steel facilities continue to deteriorate. First generation unprotected steel pipe, much of it dating to the turn of the last century, has reached or soon will reach the end of its useful life and must be replaced in a timely, cost-effective manner.

Q. Do safe and reliable system operations requirements demand replacement of

Columbia's unprotected steel facilities?

A. Yes. Continual system degradation due to unrelenting corrosion will challenge Columbia's ability to meet peak day needs and operate the system safely. Therefore, continuation of Columbia's main replacement program is an essential alternative to a high leakage rate and the associated public risks and additional strain on the system when required to meet peak day demands on the system.

Q. Are you saying Columbia's system is unsafe?

A. No, I am saying the system is safe right now, as evidenced by our ability to address Type-1 and Type-2 leaks appropriately, as well as all of the other operational improvements including more frequent leakage surveys, better emergency leak response, and a continued focus to reduce the backlog of open Type-2 leaks that are described in this testimony. The "system" is comprised of thousands of miles of wrought iron, cast iron, bare steel, cathodically-protected steel, and plastic pipe. The material initially at risk is first generation bare steel, cast iron, and wrought iron. Evidence further indicates that the corrosion with respect to unprotected coated steel is accelerating, gradually causing more leaks. Cast iron pipe also is quite old and is in need of replacement due to its age and vulnerability to fractures caused by ground movement. Wrought iron is a hybrid of cast iron and bare steel that demonstrates very similar corrosion characteristics to that of bare steel.

All of that said, while the system is currently safe, Columbia must, as a prudent operator, address the systemic problem of replacing its unprotected steel, cast iron,

and wrought iron facilities. And finally, the issues that are manifesting themselves on first generation plastic (though the risks have not yet risen to the level of risk associated with bare steel, cast iron, or wrought iron), as discussed elsewhere in this testimony, also necessitate a measured replacement strategy geared to those locations where Columbia is uncovering this pipe in the course of replacing other facilities.

Q. How does Columbia classify leaks it detects on its system?

A. Columbia classifies each gas leak according to its severity: Type-1, Type-2, or Type-3. A Type-1 leak is hazardous and requires immediate remediation and repair. A Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as "non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."

These gas leak classifications are defined in the Gas Piping Technology Committee ("GPTC") ANSI Z380.1 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and State pipeline regulators, including the Commonwealth of Pennsylvania, as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards."

Q. Will Columbia's accelerated replacement program provide customers with any other benefits besides the replacement of bare steel and cast iron pipe with plastic

and cathodically protected steel?

A. Yes. Columbia is replacing the segmented, 19th and early 20th century low-pressure designs of its first generation system with a more integrated, 21st century system design. This integrated, higher pressure system (up to a maximum of 99 pounds operating pressure, though will typically operate at 60 PSIG) will enable Columbia to substantially reduce the current need for district pressure regulator stations throughout its system, resulting in a safer, easier, and more reliable system to operate. Instead, each residence will have a small domestic sized regulator installed just up-stream of the meter to reduce the pressure before it enters the house. A distribution system operating at these higher pressures also will enable Columbia to install new safety devices in areas to be upgraded. As part of the upgrade, Columbia is installing excess flow valves on nearly all services connected to the replacement mains.[4] For approximately $25 per replaced residential service, or less than $150 for the average commercial service, these excess flow valves will shut off gas to a residence or business in the event of a large pressure differential, which is indicative of a major gas leak or a service damaged by excavation. Over time, this results in a system where services are much less vulnerable to safety risks from third-party damage.

Finally, this migration to higher pressure systems will provide customers with much

[4] The exception would be for those commercial and industrial customers whose consumption is over 5,000 cubic feet per hour.

more flexibility in adding new, high efficiency equipment, and in allowing for the installation of smaller, less expensive interior piping systems (such as CSST—Corrugated Stainless Steel Tubing), which is designed to operate at two pounds of inlet pressure (current low pressure systems typically operate at a maximum of 7 inches of water column, which is roughly 1/8th of the 2 PSIG pressure required). Notably, the 60-pound system design discussed above provides the maximum flow capacity for a given size of medium density polyethylene pipe, and enables the Company to routinely provide 2-pound pressure delivery systems to customers. It should also be noted that as a result of the quarter pound of pressure associated with low pressure delivery systems, this type of service is not available to customers currently served from low pressure systems.

Q. How will main replacements affect the Company's leak repair experience?

A. The long term view is that as the percentage of bare steel and cast iron pipe is materially diminished, we expect to see a reduction in grade 1 and grade 2 leakage repair caused by corrosion. However, this impact is not anticipated in the near term. Cast iron and bare steel remaining to be replaced continues to drive grade 1 and grade 2 leakage repair activities. Currently, nearly 71% of the Company's current main Type-1 and Type-2 leakage is corrosion related (exclusive of excavator damage) and 75% of the leaks on service lines are also caused by corrosion. Additionally, Columbia is working to reduce the time that grade-2 leaks remain open, adding additional O&M expense.

Q. What benefits inure to the public from Columbia's ongoing replacement of its aging facilities?

A. Columbia is removing deteriorating portions of its system and enhancing the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Its system will continue to be able to provide deliverability at its maximum allowable operating pressure ("MAOP"), thus the public will receive better service, with fewer interruptions. Customers are currently experiencing the benefits of the investments being made to enhance the safe and reliable delivery of their natural gas service. During the "Polar Vortex" of 2014, Columbia's distribution system performed well and experienced no significant issues with service interruptions or curtailments of firm customers. The same has held true through the cold weather events of the 2014-2015 winter heating season. Further, this massive and structural system replacement program is adding jobs throughout Columbia's service territory, both in the ranks of full-time Columbia employees (these include engineers and engineering technicians, land agents, and construction inspectors), as well as the contractors who perform the actual pipe replacement (which includes laborers, equipment operators, crew leaders, and support staff) and associated support services such as: paving, traffic control, trucking, sand and gravel, and a myriad of other material purchases and support activities that are needed to execute this type of strategic replacement program. Finally, to underscore the magnitude of this program, at the peak of 2014 Columbia had 90 construction

crews employing approximately 500 to 600 contractors and 20 to 25 restoration contractors employing approximately 200 employees.

IV. Federal Pipeline Safety Rules and Advisories

Q. Please describe the Federal Pipeline Safety Rules and Advisories that are affecting and will continue to affect Columbia's Pipeline Safety Strategy and Operational Execution.

A. Some of the more significant and impactful Final Rules or Advisories that have been issued in the last several years or are being considered for the future are as follows:

- Control Room Management (76 FR 35130) - This rule expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This rule requires that Operators define the experience requirements, create training programs, and establish clear roles and responsibilities for Control Room Operators. Further, the rule mandates that appropriate shifts, and maximum hours of work be established for control room operations. The deadline for pipeline operators to implement the procedures for roles and responsibilities, shift change, change management, and operating experience, fatigue mitigation education and training was October 1, 2011, 16 months sooner than the original regulation.

- Mechanical Fitting Failure Reporting Requirements (76 FR 5494) - This final rule is an amendment to PHMSA's regulations involving DIMP. This final rule revises the pipeline safety regulations to clarify the types of pipeline fittings involved in the compression coupling failure information collection, and changes the term "compression coupling" to "mechanical fitting," which aligns a threat category with the annual reporting requirements and clarifies the Excess Flow Valve ("EFV") metric to be reported by operators of gas systems. (As a result of this change from "compression fitting" to "mechanical fitting" Columbia is likely to report more "mechanical fitting" failures in its system than it has historically reported.)
- Integrity Management Program for Gas Distribution Pipelines (74 FR 63906) - This final rule amends the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management ("IM") programs. The IM programs required by this rule are similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution pipelines.

In addition to the final rules above, the following are proposed rules or recommendations that are currently being made by, or are under consideration by PHMSA:

- Pipeline Safety: Pipeline Damage Prevention Programs (PHMSA 2009-0192 RIN 2137-AE43) - This Advance Notice of Proposed Rulemaking seeks to

revise the Pipeline Safety Regulations to: establish criteria and procedures for determining the adequacy of state pipeline excavation damage prevention law enforcement programs; establish an administrative process for making adequacy determinations; establish the Federal requirements PHMSA will enforce in states with inadequate excavation damage prevention law enforcement programs; and establish the adjudication process for administrative enforcement proceedings against excavators where Federal authority is exercised. This requirement continues to work its way through the PHMSA regulatory approval process, and is expected to be approved. Further, unless the Pennsylvania Legislature passes the One Call Enforcement Bill that has been introduced, we are likely to see this federal enforcement in Pennsylvania which would have material impact on all Pennsylvania gas utilities.

- Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences (PHMSA 2011-0009 RIN 2137-AE71) – The National Transportation Safety Board has made a safety recommendation to PHMSA that excess flow valves be installed in all new and renewed gas service lines, regardless of a customer's classification, when the operating conditions are compatible with readily available valves. This requirement continues to work its way through the PHMSA regulatory approval process, and is expected to be approved.

That said, Columbia has already modified its procedures to require its construction crews to install excess flow valves on all new and replacement commercial installations up to 5,000 Cubic Feet Per Hour.

- Pipeline Safety: Safety of Gas Transmission Pipelines (PHMSA 2011-0023 RIN 2137-AE72) – PHMSA is considering in this advance notice of proposed rulemaking whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether IM requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA is considering concerning IM requirements is whether the definition of a high-consequence area should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods.
- NTSB Recommendation P-12-17 Safety management System (API Draft Recommended Practice 1173) – Conceptually this recommendation is built on the premise that managing the safety of a complex industry requires a system of efforts to address multiple, dynamic, changing activities, and circumstances. It further reflects the PHMSA view that if the industry is to achieve the goal of zero incidents, a highly structured and comprehensive effort is required. The broad components of these plans would include:

- Demonstrated management commitment
- Structured pipeline safety risk management decisions
- Increased confidence in risk prevention and mitigation
- Provide a platform for shared knowledge and lessons learned
- Promoting a pipeline safety oriented culture

The ultimate purpose of this initiative is intended to produce a continuous pipeline safety improvement cycle among pipeline operators of "Plan-Do-Check-Act."

Q. Will PHMSA's focus on Transmission Lines have any significant impact on Columbia operations?

A. Yes, "Transmission Line" is defined in CFR 49, Part 192 as "a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream of a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS [System Minimum Yield Strength]; or (3) transports gas within a storage field." Columbia has approximately 65 miles of transmission class facilities that meet this definition. Further, following the San Bruno California explosion which occurred on a PG&E Transmission Line in 2010, PHMSA has focused attention on the quality and comprehensiveness of system records for these lines, particularly around the pressure testing data, pipe design information, and wall thickness of existing transmission line systems. Columbia, like many other LDCs and

transmission companies, is lacking certain data, particularly on segments installed prior to current code standards and the issuance of Federal Pipeline Safety Regulations instituted on August 1, 1971. Further, Columbia is waiting on specific federal guidelines for these segments that are expected to be issued soon, but believes this guidance will necessitate a program to replace many, if not all, of its pre-1971 transmission lines in Pennsylvania that lack data that was not federally mandated at the time of installation. The increased spending that is shown in the Company's response to Standard Data request GAS-ROR-014 in the capital budget category of "betterment" for 2015 and beyond reflects increased pipe replacement work that Columbia expects to have to conduct on these pre-1971 transmission lines. If, however, the federal guidance does not require the transmission line replacements that the Company anticipates, this money will be spent in Pennsylvania on the first generation pipe replacement program, as both of these categories of spend represent pipe replacement projects on older, potentially "at risk" facilities. PHMSA continues to focus heavily on Transmission Operations with a new Notice Of Proposed Rule-Making (NOPR) that would either change the definition to make the inspection procedures and safety requirements of the various class locations more rigorous, or to expand the classification of High Consequence Areas, requiring changes in both system design criteria as well as on-going maintenance in those areas.

V. Strategic O&M Initiatives

Q. Please summarize the results of your assessment of Columbia's pipeline safety risks and opportunities.

A. In 2006, 2007, 2008 Columbia undertook safety initiatives which included the following activities, among others:

- Conducting frequent leakage surveys on "first generation" facilities;
- Launching a structural "first generation" pipe replacement program;
- Undertaking a focused process to reduce third-party damage;
- Initiating a program to reduce the backlog of open Class-2 leaks; and
- Eliminating the backlog and accelerating the abandonment of inactive services.

In 2013 Columbia initiated the following additional safety initiatives to further enhance the safety of its distribution system:

- Aggressive management of right-of-way vegetation;
- Continued acceleration of the repair rate of open Type-2 leaks;
- Continued efforts to remediate atmospheric corrosion on above ground structures;
- Ensuring exposed mains have appropriate cover;
- Increased use of camera-based technology to identify cross-bore conflicts;
- Began to implement Hi-Accuracy GPS program;

- Expanded use of Vac Trucks to dig test holes on facilities where the existing tracer wires have either been broken or suffered degradation to the point there is no longer electrical continuity.
- Ensure MAOP documentation in compliance with federal requirements; and
- Enhanced damage prevention advertising and contractor outreach, with a particular emphasis on educational outreach to children through targeted educational programs

Q. Please discuss Columbia's strategy regarding O&M safety initiatives going forward.

A. Columbia's strategic DIMP Plan, and the impact that it will have on O&M policy for safety initiatives, remains unchanged. The Company continues to focus its efforts and resources on the top risks to the Company's system as enumerated in its DIMP Plan and as modified based on the annual DIMP data review, which sometimes results in risk reprioritizations or other updates to the plan. Columbia is expanding focus in several critical areas to maintain and enhance its operational capabilities:

- As Columbia works to build the pipeline of the future we also find ourselves in the midst of building the workforce of the future. With the ramp up of our capital program we have experienced the transfer of employees from O&M positions to construction positions; in addition we continue to see an increase in the number of employees who are eligible to retire. We see both opportunity and risk in the current and future

transition of our workforce. Columbia's historical methods of training were developed in an era of very low turnover and well-established institutional knowledge. These traditional training methods will not address the increased risk of human error to our system introduced by this large scale workforce transition. We must adjust our methods of training to reduce that risk for new and existing employees. Columbia is currently creating formal employee training and qualification program to address the DIMP and system risks associated with human error in the field. These programs will not only include more classroom time and far more stringent testing procedures, but will, where appropriate, require hands on demonstrations of necessary skills to validate employee or contractor qualification competency. Columbia has made additional organizational changes to focus on training and development of employees. While this adds to current O&M expenses, it is vital that we are effective in preparing the next generation of employees, so as to minimize risk both to employees and the general public

- Columbia is constructing a new training center that will provide the facilities needed to conduct classroom training and enhanced hands on training. The facility will be used for multiple training purposes including; new employee training, employees transitioning into higher skilled positions, and for annual refresher training for the existing

workforce. A great deal of thought, research and best practices were considered when developing the new training approach and designing the training facility. Trainers traveled to industry leading training facilities and natural gas organizations across the country. Best practices of organizations outside the natural gas distribution industry who are trained to respond to crisis and emergency situations were also studied. Focus groups were formed to gain insight and obtain feedback from front-line employees about their perceptions of and experiences with training, as well as the accessibility of standards while performing on-the-job tasks. The curriculum being developed will incorporate end to end training of Columbia's field technology, such as mobile data terminal units and work management systems, to technical training for operator qualifications. This end to end training will educate employees on every aspect of the job and its importance, from physical work performed to its accurate documentation. This facility will replace the Jeanette Pennsylvania facility that was severely damaged in a tornado March of 2011.

- With the current and anticipated entry of new employees to the workforce, Columbia has also made adjustments to the span of control for frontline leaders. Historically higher spans of control were manageable because of low turnover and a high level of workforce

experience and tenure. The increased number of new employees entering the workforce requires frontline leaders to spend additional time providing guidance and supervision. To achieve an effective span of control Columbia has added four frontline leader positions.

- As mentioned previously in my testimony, damage prevention continues to be a focus in reducing ongoing system risk. Columbia has made significant progress in reducing facility damage rates. In 2007 damages per thousand locates were at 5.39, which had been reduced in 2014 to 2.65 damages per thousand locates. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven effective. However, overall damage prevention rates, while improved from historical levels, have plateaued over the last three years. Contractor negligence remains the highest cause of damages to our system and has increased from 47% of total damages in 2010, to nearly 61% of total damages in 2014. In an effort to further reduce damages in this area Columbia has added four damage prevention coordinators to expand contractor outreach efforts.
- During the winter of 2014-2015, failures were experienced with field assembled risers and have been identified as a DIMP risk. Columbia is developing a program to address the risk of field assembled riser failures. The program will included a survey of customer owned and company

owned service lines to identify and quantify field assembled risers in use. Columbia will use the collected data to further asses DIMP risk and prioritize efforts. Columbia has begun replacing field assembled risers identified on company owned service lines.

The pipeline safety DIMP Plan accelerated action enhancement items identified above, in conjunction with the Company's ongoing bare steel, cast iron, and wrought iron accelerated replacement program, are designed to address the key risks identified in Columbia's DIMP Plan, and continue to reduce the pipeline safety risks that are inherent in the Columbia operating system. The costs of these incremental O&M activities are included in Columbia's cost of service calculations filed in this case, and sponsored by Company witness Miller.

Q. What additional detail is available to demonstrate how Columbia has improved its system operations?

A. Some of the results from DIMP driven practice enhancements or procedure changes include:

- Reduction in the number of open Type-2 leaks in the Columbia distribution system as measured by the annual Federal DOT report. It is worth noting that corrosion on bare steel is identified as a high level DIMP Plan risk in the Columbia system, and that roughly 75% Type-2 leaks in the system are

caused by corrosion on bare steel. Further, this is a significant undertaking in assuring safe and reliable service to customers, as the greater the number of leaks in a system and the longer they are left unattended, the greater the potential risk of gas migrating into a structure or other underground facility. The result of this focused effort was that at the end of 2007 (the first full year of Columbia's annual system wide bare steel survey), Columbia reported a total of 3,755 open Type-2 leaks in its Distribution System. As of December 31, 2014, Columbia had reduced that number to 1,702 open Type-2 leaks, which equates to a nearly 55% reduction in open Type-2 leaks over the last seven years. In addition, as indicated in our DIMP Plan initiatives Columbia intends to continue to accelerate its Type-2 leak repairs in order to further reduce the number of open Type-2 leaks.

- Improve Columbia's locating performance as measured by third-party damage per thousand locates. This operational safety metric is particularly critical, as third-party damage is the leading cause of federally reportable pipeline incidents (e.g. Death, Injury requiring hospitalization, or Property Damage over $50,000) in the United States. In addition, it is a high level risk identified in Columbia's DIMP Plan. Since 2006, Columbia has undertaken a comprehensive process designed to improve locating performance and reduce third-party damage to Company facilities. This process has included tighter management and more stringent performance standards for locators,

and resulted in a pilot program initiated in 2009 to bring the locating function back in-house for two large operating centers in Pennsylvania. In early 2012, Columbia decided to bring all locating back in-house. The Company made this decision because the data from the pilot program consistently showed that in-house locators delivered better third-party damage results than those of any of the contract locators who were performing this work for Columbia. Combined with improved techniques to locate difficult to locate facilities, locator error has significantly improved over time. Locator error in 2010, as a percent of damages, was 16.62% compared to 2014 performance of 10.27%.

Columbia continues to routinely conduct face-to-face meetings with excavators who are frequent damagers and has added resources to accelerate this activity. Damage prevention coordinators educate contractor employees in safe excavating practices, as well remind them of the potential consequences of damaging natural gas facilities. These efforts have resulted in a 51.5% reduction in third-party damage on the Columbia system between 2006 and 2014, from a damage per thousand (locate requests) rate of 5.47 in 2006 to a damage per thousand rate of 2.65 through December 31, 2014.

- Columbia began a cross bore program in September of 2013 as a result of identifying cross bores as a potential risk in its DIMP plan. Working with local municipalities, Columbia has inspected over 67 miles of sanitary and

sewer mains, and 4,800 customer laterals. During this inspection, 111 cross bores were identified, with 75 of those involving Columbia's system. Given program results, cross bores have moved from a potential risk to a high risk in Columbia's DIMP plan. The cross bore program is an example of how DIMP can be used in identifying and mitigating system risk.

VI. Columbia's Operating Performance

Q. In addition to Columbia's intense focus on pipeline safety, what are some of the practice enhancements or procedure changes regarding operating performance that are specific to customer delivery performance?

A. Customer service initiatives that Columbia has undertaken over the last 5 years include:

- Columbia has recently initiated a number of customer service improvement efforts. These efforts include piloting a two hour appointment window, implementing a customer ambassador program, and an increased focus on customer communications. These efforts, combined with improved customer service options, have positively impacted the customer experience. In 2014, Columbia Gas of Pennsylvania was awarded by JD Power for ranking first in customer satisfaction among all midsize utilities in the east region, reflecting our customers' recognition of the improvements being made on their behalf.

- Increase Columbia's 60-minute or less Emergency Response Rates. Emergency response rates are integral to public safety. The sooner the first Columbia responder arrives at a possible emergency, the quicker the situation can be stabilized, made safe, and ultimately remediated. Since 2006, Columbia has undertaken a very structured approach to improving its emergency response times, including the addition of field operations positions, additional off hours shifts, the use of GPS technology to enable dispatching the closest/quickest responder to emergencies, and driving an increased focus with all employees on the need to respond to reported emergencies as quickly and as safely as possible. In addition, Columbia continues to make enhancements in an effort to keep emergency response rates down. Starting in 2011, Columbia implemented an automated crew call out and resource management system to call the service technician located closest to an issue that requires a response after hours. Columbia also negotiated additional language to our labor contracts which requires a service technician to be on Emergency Responder Rotation so that we have an initial responder available 24 hours a day, 365 days a year. The results of these focused efforts have resulted in improved performance. A comparison of the data showing the 60-minute or less response rates from 2006 to 2014 is as follows:

	2006	**2014**

➢ Normal Hours	98.13%	99.69%
➢ After Hours	92.34%	96.67%
➢ Weekends & Holidays	88.99%	94.98%
➢ Total Performance	97.00%	98.12%

- Increase the number of Columbia's on-time customer appointments, as measured by the overall annual percentage of on-time appointments met. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service related activities, it is incumbent upon the Company to be as efficient as possible with the customers' time. Therefore, in 2007 Columbia began to focus specific attention on improving its percentage of on-time appointments. It did so by tasking the Integration Center (Columbia's Centralized Scheduling and Dispatch Center) to improve field employees' daily schedules to align more closely with the needs of customer appointments, and to shift non-emergency work when possible to meet appointments that, for a variety of reasons, might otherwise be missed. As a result of these efforts, Columbia has been able to improve its on-time appointment rates from 97% in 2006, to a rate of 97.77% in 2014.

Q. Please describe the Company's reduction in OSHA recordable injuries.

A. Columbia continues to enhance its culture of safety for customers, communities, and employees. Employee safety has significantly improved and has achieved top decile performance in OSHA Recordable Injuries, as measured by AGA benchmarking, for the second year. For comparison, at the end of 2006, Columbia had 48 Occupational Safety and Health Administration ("OSHA") recordable injuries, in 2014 that number declined to 5 OSHA recordable injuries. Columbia received industry awards in 2014 from the American Gas Association and the Energy Association of Pennsylvania in recognition of its industry leading performance. Our goal is for every employee to go home safe and healthy every day. Columbia achieved this performance through multiple cultural building efforts:

- In 2014 Columbia implemented Safety Telematics across its operations. This program provides real time feedback to drivers on their driving performance. It also provides detailed reporting to enable analysis of driving trends and habits providing actionable information to improve driver safety.
- Local and state-wide safety teams made up of engaged front line workers, leaders, and managers. These teams make recommendations on, and implement, safety improvement opportunities.
- Root cause analysis of every OSHA recordable injury and preventable vehicle accident that involves a Columbia employee. Near miss discussions are also conducted.

- Safety training is delivered to all employees. This training spans skills from driving maneuverability to office ergonomics.
- An employee safety audit program in which leaders perform safety audits on field activities, and provide feedback to employees' on their safety performance.
- Employees evaluate the hazards at each jobsite prior to beginning work and complete a safety check list which is reviewed with each employee.

Q. Regarding Columbia's operating performance, does the Company meet or exceed state and federal requirements for leak surveying?

A. Yes, in 2007 Columbia began an accelerated leakage survey program to inspect all bare steel mains annually, instead of the three-year interval which is required in the leakage survey requirements of CFR 49, Part 192. The result of this is that Columbia routinely exceeds the requirements of existing Code of Federal Regulations, which provides the Company the ability to discover system leakage on a much timelier basis than if it were only meeting the minimum federal standards. In addition, as a result of the Commission's Tentative Order regarding Natural Gas Pipeline Replacement and Performance Plans, at Docket No. M-2011-2271982, Columbia agreed, and has continued to perform a second annual business district survey during each winter period.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Project Name	Installation Pipe Size (inches)	Install Footage (feet)
D8542	6	4,200
D1254	8	4,725
Pennsylvania Ave	8	3,000
D7007 Gate Nest	4, 8	2,997
Grandview	2, 4, 6, 8	2,360
South Mt Vernon	2, 4, 6	4,050
Broadway (Meyersville)	2, 4, 6, 8	1,977
SR 0088	2, 6	1,313
Pennsyvania Ave (Gregg)	2	3,000
Walnut	2, 6	1,475
North	4, 6	954
Vine	2, 4, 6, 8	2,875
Broadway (Berlin)	2, 4	893
West Main	4	250
Ash Street	2, 4	3,585
Pittsburgh St bet N. Mt Vernon and Johnson	6, 8	836
Pittsburgh St bet Enamel St and Fairview St	6	750
F Alley	2	370
Wood St (California)	2, 4, 6	5,377
East Main	6	650
Wood St (Monongahela)	2	802
8th Street	2, 4	535
Fayette Street	8	650
Yough River Crossing	8" St, 8" Pl	2,700
Mulberry	2, 4	1,270
D7194 - Warwick Mine	2, 6	3,460
New Stanton North	2, 4	7,800
Route 31	4	2,700
Baileys Crossroads	2, 4	1,000
Brownsville Area School Relocation	8	590
Glencoe Avenue	4	1,900
Mclain Street	4	340
Stowe Avenue	2, 4	1,155
Bell Avenue	2, 4, 6	2,750
Parkfield Road	4	1,900
Mitchell Avenue	4	2,030
Mansfield Avenue	2, 4	2,050
Wylie Avenue	2	1,800
Parker and Beverly	2	1,000
Highgrove Drive	2, 4	4,531
Hamilton Road	6	450
Steubenville Pike	6	1,320
Arlington (Sterling to Eleanor)	4	1,222
McLaughlin Run Road MP	4	1,150

McLaughlin Run Road HP	8	1,140
McRoberts Road Valve	8, 20	200
Old Clairton Road	6	1,154
Sunnyfield Drive	4	3,200
Sprucewood Drive	4	390
Donati	6	350
Rennie Drive	4, 6	2,010
Walnut Street	2	150
Orchard Drive	2, 4, 8	10,540
Southside Phase 1	2, 4	4,755
Castle Shannon Boulevard	6, 8	1,660
D584 (Deerfield Road)	2	6,225
S. Main Street Extension	4	3,600
Fawcett Church Road	2	710
Ridgewood Drive	6	900
Vista Valley Drive	2	6,300
Western	2	1,750
Wylie Avenue	2	140
Bower Hill Road	2	2,060
Industrial Park/Noblestown Rd	6	2,880
Archer Street	6	60
Country Club Road	6	780
Becker Street	2	795
101 Trenton Circle	2	54
Elm Street	2, 4, 6	9,291
Broad Street	2, 4, 6, 8	26,620
Wylie Avenue	2, 8	12,030
D1581 (USC to Hastings Mill)	12	7,400
Battleridge	2, 4	475
Island	6	208
Cedar	2, 6, 8	965
25 Holt St	2	140
W College St	6	690
Arnold St.	2	330
Oak Rd	2	1,520
Forest Road	2	1,600
Gateway Ave	2, 4	1,000
D-272 from Branch Rd and Edgewater	8	1,800
Highland Ave	4	2,953
Merriman Rd	6	1,720
Norwood Ave	4, 6	2,340
Johnson	4, 6	3,027
Roosevelt Rd and Bradshaw Dr	2, 4	2,880
7th Ave	2, 4, 8	2,825
Amsler	4	820
D-81 between Wexford Rd and Tierra Vista Dr	2, 6	3,820
Winterburn	4	750

High St off of Chapel Rd	2	2,720
11th Ave from 7th St to Allegheny	4	1,320
McMillen Ave	2	2,000
Camp Meeting Rd bet Skymark Ln and Young Rd	2, 4	2,600
6700 Church Ave	2	300
9th Avenue	2, 4, 6	2,160
Hoenig Rd	2	760
Fairlane between Careywood & Big Beaver	4	2,080
Kenyon Avenue Replacement Project	2, 4	4,120
Glenfield Rd, Ferry Rd Replacement	2	2,780
Thawmont Dr Replacement	2	2,400
Cochran St between Nevin & Beaver	4, 6	2,825
6th Avenue - Replacement Job	2	2,000
Broad Street Between Kost/Mohawk	4	1,700
5th St, Beaver	4	850
40th St, Beaver Falls	2	600
Lincoln Rd, Bradford Woods	2	350
Elm Rd from 5th St To Wilson Ave	4	3,800
D-1680 Bet Lacock Av and Locust Ln	10	8,000
Franklin Ave	2	400
Falls Ave Replacement Project	2, 4	2,942
Furnace St	2, 10	2,700
Rhodes Place Replacement & Uprate	4	1,300
Court St at Ray St	2, 4	750
Pearson St Between Fairview & Taylor	2, 4	1,350
Montgomery Replacement Project	2, 4, 6	2,150
Harrison St Replacement Project	4	870
Blue Jay Portersville Rd	2, 4	3,175
Vista Ln Replacement Project	2	1,115
4th St Ellport Replacement Project	4	1,200
Lundys Lane	8	80
Hamilton St Replacement Project	4, 6	2,000
Wurtemburg Rd Replacement Project	2, 4, 6	5,285
D-22 At Countryview Road Replacement	2, 8	10,400
Home St-New Castle	2	660
Laurel Replacement Project	2, 4, 6	3,078
Mt Herman Church Rd At Mill Bridge	4	1,080
Clearview @ Reynolds St/ N-C	2	170
Palo Alto Dr (D-500) Replacement	4, 6	2,400
Burns St at Scotland Lane New Castle	2, 4	690
Sumner Av - New Castle	2	800
McClelland	4	1,200
D-1601 Phase IV	8, 12	5,600
Avalon Park Betterment D-213	6	1,300
Mt Pleasant Rd	6	2,342
D-1009 Gottlieb - Street Improvement	2, 8	3,000
Pine Twp Rd Widening	4, 6	1,860

D-5242 Clintonville Replacement Project	4	4,700
Palmer	2	1,000
SR 208 and Dog Leg Rd Replacement	2, 4	2,800
SR 208 @ Ron McHenry Replacement	4	1,500
Popetown Road Replacement	2	970
SR2011 Nickleville Road Replacement	2	4,030
Knox AMRP Phase 1	2, 4	9,625
D-22 Between SR 308 and Goff Rd	2, 8	7,620
SR 66 Replacement Project	2, 6	1,400
Carwick Road Replacement	2	1,290
High St Replacement Project	2	2,760
Pleasant/Bennett St Replacement Project	4, 8	3,460
Bank St Area Replacement	4	1,000
Wagner Ave Replacement	6	1,000
E Main Replacement	2	1,860
Pleasant and Hillview Dr Replacement	2	4,670
Bradley St Replacement	2	350
Hickory St Area Replacement	2	1,850
D-4227 Buena Vista Dr	2, 8	11,000
Harbaugh St, Chestnut to Logan	6, 8	330
Dean Rd, Warrendale Bakerstown to Dean	2	3,920
Larry St Replacement	2, 4	7,502
601-609 Wayne Ave	4	160
Clinton St bet McCaslin and Lincoln	6	2,000
N Carver St Area Replacement	2, 6, 8	6,190
Park Forest	2, 4	4,200
University	2	2,086
Beaver	4	940
Pike Alley	2	720
Atherton St	2, 4, 6	4,570
Church Rd Farm Tap Elim	2	935
W Monroe St	2, 4	3,655
Greenwood Rd	2, 4, 8	5,185
W Market St	2, 4, 6, 8	8,720
Lee St	2, 4	1,535
E Market St / York City	2, 4	1,735
D1661 North York WHP	12	5,100
Strathcona	2	2,620
Pinehurst	2	3,099
S. Queen St (Revised)	2, 6	8,596
Valley Road	2, 4, 6	7,680
Clover Lane	2	3,140
Vander & Boundary	2	500
East Queen Street	2	650
S. Howard St.	2	275
Paul St.	2	4,270
Locust St. (Hanover)	2, 4	4,104

Winter Ave. Glen Rock	2	1,420
Center St.	2, 4, 6	1,522
Carlisle St.	2, 4, 6	6,626
Mt. Rose Southern Bore	2, 8	2,500
Mt. Rose Ave. Western Replacement	6	2,235
Haines Rd.	8	2,075
Baltimore St.	6	543
E Middle St	2, 8	3,160
Zerfing Alley	2, 4	325
Hanover St Eastern Gettysburg Project	2, 8	4,886
Rampike Hill Rd	4	950
Seminary Ave	2	1,314
Fohl St	4	2,010
Linden Ave	4	1,500
Franklin St	2, 4	3,380
Seminary St. Mercersburg	2, 4	1,999
S Fayette St	2	1,315
Franklin Farm Ln	4	1,250
Greendale	2, 8	558
Southern	8	5,000