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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH KEYSTONE BUILDING
400 NORTH STREET, HARRISBURG, PA 17120

BUREAU OF
INVESTIGATION
&
ENFORCEMENT

June 7, 2022

Via Electronic Mail
Deputy Chief ALJ Christopher Pell
Administrative Law Judge John M. Coogan
Pennsylvania Public Utility Commission
Office of Administrative Law Judge
cpell@pa.gov
jcoogan@pa.gov

Re: Pennsylvania Public Utility Commission v.
Columbia Gas of Pennsylvania, Inc.
Docket No.: R-2022-3031211
I&E Direct Testimony and Exhibits

Your Honors:

Enclosed please find the following prepared **Direct Testimony and Exhibits** of the Bureau of Investigation and Enforcement's (I&E) witnesses:

D.C. Patel	I&E Statement No. 1 **PROPRIETARY**	I&E Exhibit No. 1 **PROPRIETARY**
Chris Keller	I&E Statement No. 2	I&E Exhibit No. 2
Ethan H. Cline	I&E Statement No. 3	I&E Exhibit No. 3
Tyler Merritt	I&E Statement No. 4	I&E Exhibit No. 4

Copies are being served on parties of record per the attached Certificate of Service. Should you have any questions, please do not hesitate to contact me.

Respectfully,

Erika L. McLain

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Enclosures

cc: Rosemary Chiavetta, Secretary (*Cover Letter and Certificate of Service only – via e-file*)
Per Certificate of Service

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No.: R-2022-3031211
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that I am serving the foregoing **Direct Testimony and Exhibits** dated June 7, 2022, in the manner and upon the persons listed below:

Served via Electronic Mail Only

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I&E Statement No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Direct Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

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

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. An outline of my education and employment history is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) and make recommendations regarding the Company's rate of return, including capital structure, cost of long-term debt, cost of short-term debt, the cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending December 31, 2023.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A BASE RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income and is usually expressed as a percentage of the amount of capital invested over a given period of time.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

RR = E + D + T + (RB x ROR)

Where:

RR = Revenue Requirement

E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes
RB	=	Rate Base
ROR	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component, which has financed rate base, to total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure.

Because of this difficulty, a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The I&E table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Columbia witness Paul R. Moul is the primary witness addressing rate of return (Columbia Statement No. 8). Mr. Moul provided analysis for the claimed capital structures, long-term debt, short-term debt, and cost of common equity for Columbia.

Q. PLEASE SUMMARIZE THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. Moul recommended the following rate of return for the Company based on its FPFTY ending December 31, 2023 (Columbia Exhibit No. 400, Schedule 1, p. 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.23%	4.51%	1.95%
Short-Term Debt	2.39%	1.65%	0.04%
Common Equity	54.38%	11.20%	6.09%
Total	100.00%		8.08%

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for the Company (I&E Exhibit No. 2, Schedule 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.23%	4.51%	1.95%
Short-Term Debt	2.39%	1.65%	0.04%
Common Equity	54.38%	9.61%	5.23%
Total	100.00%		7.22%

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits of risk in comparison to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR GAS INDUSTRY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are most like the natural gas distribution company subject in this proceeding. I applied the following criteria to Value Line's Natural Gas Utility company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry;
2. The company's stock must be publicly traded;
3. Investment information for the company must be available from more than one source, which includes Value Line;
4. The company must not be currently involved/targeted in an announced merger or acquisition;
5. The company must have four consecutive years of historic earnings data; and

6. The company must be operating in a state that has a deregulated gas utility market.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING HIS GAS PROXY GROUP COMPANIES?

A. Mr. Moul began with the ten gas utility companies in Value Line's Investment Survey. From there, he eliminated one company, UGI Corp., due to its diversified businesses, which includes six reportable segments. These various business segments include propane, international liquefied petroleum gas segments, natural gas utility, energy services, and gas generation. Mr. Moul also noted that one of the companies in his Gas Group, South Jersey Industries, Inc., entered into an agreement to be acquired by a private equity investor. However, Mr. Moul did not remove South Jersey Industries, Inc. as his analysis was completed prior to the announcement of the acquisition. Beyond his rationale for excluding UGI Corp., Mr. Moul has not provided a list of criteria used to determine the remainder of his "Gas Group" other than that the Gas Group is made up of the companies the Commission's Bureau of Technical Utility Services uses to calculate the cost of equity in its Quarterly Earnings Reports (Columbia Gas Statement No. 8, p. 5, lines 2-20).

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I included the following six companies in my proxy group (I&E Exhibit No. 2, Schedule 2):

Atmos Energy Corp.	ATO
Chesapeake Utilities Corp.	CPK
NiSource Inc.	NI
Northwest Natural Holding Co.	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR

Q. WHAT PROXY GROUP DID MR. MOUL USE IN HIS ANALYSIS?

A. Mr. Moul utilized the following nine companies in his Gas Group (Columbia Exhibit No. 400, Schedule 3, p. 2):

Atmos Energy Corp.	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Holding Co.	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Holdings, Inc.	SWX
Spire, Inc.	SR

Q. DO YOU AGREE WITH MR. MOUL'S GAS PROXY GROUP?

A. Not entirely. While Mr. Moul's Gas Group included all six of the companies in my proxy group, I have excluded three of the companies he uses.

Q. PLEASE LIST THE THREE COMPANIES MR. MOUL HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED THEM FROM YOUR PROXY GROUP.

A. The three companies Mr. Moul included in his Gas Group that I have excluded from my proxy group are New Jersey Resources Corp. South Jersey Industries, Inc., and Southwest Gas Holdings, Inc. I excluded New Jersey Resources Corp. and Southwest Gas Holdings, Inc. as these companies did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business. I also removed South Jersey Industries, Inc., as it did not meet my third criterion that the company must not be currently involved/targeted in announced merger or acquisition. As stated above, South Jersey Industries, Inc. has recently entered into an agreement to be acquired by a private equity investor. Therefore, these companies should be removed from the proxy group.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary funding sources are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is summarized in the table below (Columbia Statement No. 8, p. 2, line 5 and Columbia Exhibit No. 400, Schedule 1, p. 1):

Type of Capital	Ratio
Long-Term Debt	43.23%
Short-Term Debt	2.39%
Common Equity	54.38%
Total	100.00%

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul stated that 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 that new rates are in effect (Columbia Statement No. 8, p. 18, lines 22-24).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. Although I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers, in this proceeding, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2020 capital structures, which is the most recent information available at the time of my analysis. The 2021 range consists of long-term debt ratios ranging from 35.93% to 60.71%, short-term debt ratios ranging from 0.00% to 15.91%, and equity ratios ranging from 35.60% to 60.67%, with a 2021 average of 47.95% for long-term debt, 8.74% for short-term debt, and 43.31% for common equity (I&E Exhibit No. 2, Schedule 2).

It is worth noting that the Company's equity ratio is well above the average and on the higher end of the proxy group's equity ratios. In fact, five of the six companies in my proxy group have a capital structure wherein the equity ratio is less than the Company's equity ratio. This equity heavy capital structure must be recognized when considering the Company's financial risk, as higher equity ratios generally correspond with lower financial risk which Mr. Moul acknowledges this in his risk analysis when comparing the Company's common equity ratio to his Gas Group and S&P Public Utilities (Columbia Statement No. 8, p. 15, lines 3-4).

Q. WHAT IS THE COST SAVINGS TO RATEPAYERS IF THE COMPANY WERE TO EMPLOY A 50/50 CAPITAL STRUCTURE COMPARED TO THE COMPANY'S FILED CAPITAL STRUCTURE?

A. The example below shows the cost savings to ratepayers if the Company were to employ a 50% long-term debt and 50% common equity capital structure in its cost of capital while maintaining its claimed return on equity and rate base:

Columbia Gas of Pennsylvania, Inc.			
As Filed Capital Structure			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.23%	4.51%	1.95%
Short-Term Debt	2.39%	1.65%	0.04%
Common Equity	54.38%	11.20%	6.09%
Total	100.00%		8.08%
50/50 Optimal Capital Structure			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	50.00%	4.51%	2.26%
Common Equity	50.00%	11.20%	5.60%
Total	100.00%		7.86%
Difference in the Overall Rate of Return 8.08% - 7.86% = 0.22%			0.22%
Claimed Rate Base*			$2,958,295,013
Impact Prior to Gross Revenue Conversion Factor			**$6,508,249**
(0.0022 x $2,958,295,013)			
Gross Revenue Conversion Factor**			1.42417301
Total Impact			**$9,268,873**
1.42417301 x $6,508,249			
*(Columbia Exhibit 102, Schedule 3, p. 3			
** (Columbia Exhibit No. 102, Schedule 3, p. 5)			

In this example, if the Company were to employ a 50/50 capital structure, the cost savings to ratepayers would be $9,268,873. While I understand achieving and maintaining an exact 50/50 capital structure is not truly feasible, this example is intended to demonstrate Columbia's financial security as compared to its peers and prove that Mr. Moul's various "add-ons" to his cost of equity calculations are unnecessary.

COST OF LONG-TERM DEBT

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claimed long-term debt cost rate is 4.51% for the FPFTY (Columbia Statement No. 8, p. 19, lines 16-17).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. I recommend using the Company's long-term debt cost rate of 4.51%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. Although this falls outside my proxy group's implied long-term debt cost range of 1.74% to 3.96%, with an average implied long-term debt cost of 3.09% for 2021 (I&E Exhibit No. 2, Schedule 3), I recommend the Company's cost rate of long-term debt be used as the data used to determine the long-term debt cost range does not take into account the current environment of increasing interest rates.

COST OF SHORT-TERM DEBT

Q. WHY IS SHORT-TERM DEBT INCLUDED IN THIS PROCEEDING?

A. Natural gas distribution companies (NGDCs) are able to store gas, which is advantageous because it allows NGDCs to pump gas into storage for future use during the summer months when demand and cost for gas are lower. Current gas storage is typically financed by short-term debt. Since ratemaking principles allow for the stored gas in rate base, the associated short-term debt is allowed in a company's capital structure.

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. The Company's claimed short-term debt cost rate is 1.65% for the FPFTY (Columbia Statement No. 8, p. 19, lines 20-21).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. Mr. Moul stated that the Company obtains its short-term debt from the NiSource money pool, which has commercial paper as its source (Columbia Statement No. 8, p. 19, line 25 through p. 20, line 1). The cost of short-term debt for the

Company is comprised of the London Interbank Offered Rate (LIBOR) plus a spread for NiSource commercial paper. For this rate case, Mr. Moul used the average of Bloomberg's three-month forecasted LIBOR rate from the first quarter of 2023 through the fourth quarter of 2023 of 1.47% (I&E Exhibit No. 2, Schedule 4), and when the 0.20% margin is added, Mr. Moul's short-term debt cost rate estimate is 1.65% when rounded to the nearest five basis points.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF SHORT-TERM DEBT?

A. I recommend using the Company's claimed short-term debt cost rate of 1.65%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. Bloomberg, as used by Mr. Moul, is the only reliable source I have found that forecasts a LIBOR rate at the time of my analysis, and, therefore, I do not oppose the Company's claimed cost rate. It should be noted that it is my understanding that the LIBOR rate is being phased out and being replaced with the Secured Overnight Financing Rate (SOFR). For example, Blue Chip Financial Forecast, stated that beginning in January 2022, LIBOR rates will be discontinued and replaced with the SOFR rate in forecasting short-term borrowing rates (I&E Exhibit No. 2, Schedule 5).

<u>COST OF COMMON EQUITY</u>

<u>COMMON METHODS</u>

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the classical economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk.

In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt and, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of "opportunity cost." This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. The most problematic issue with the CE method is determining what constitutes comparable companies.

Q. WHAT METHOD DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR COLUMBIA?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. I provide the results of my CAPM as a comparison and not as a check to the DCF results. Although no one method can capture every factor that influences an investor, including the results of methods that are less reliable than the DCF does not make the end result more reliable or more accurate. My recommendation is also consistent with the methodology historically used by the Commission in base rate proceedings, even as recently as 2017, 2018, 2020, and 2021.[1]

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF AS THE PRIMARY METHOD IN YOUR ANALYSIS.

A. I have used the DCF as the primary method for several reasons. First, the DCF is appealing to investors as it is based upon the concept that the receipt of dividends in addition to the expected appreciation is the total return requirement determined by the market.[2] Second, the use of a growth rate and expected dividend yield are

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[1] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company;* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131.

[2] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2010 Edition, p. 151.

also strengths of the DCF, as this recognizes the time value of money and is forward-looking. Third, the use of the utilities' own, or in this case, the proxy group's stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Finally, the DCF, through the use of a spot stock price when determining the dividend yield and analysts who generate forecasted earnings growth rates, almost certainly takes current inflationary trends into consideration, therefore, it contains the most up-to-date projected information of any model. Therefore, the DCF method is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM AS A COMPARISON IN YOUR ANALYSIS.

A. I have included a CAPM analysis only as a comparison and not as a recommendation because while both the CAPM and the DCF include inputs that allow the results to be specific to the utility industry, the CAPM is far less responsive to changes in the industry than the DCF. The CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the outcome of each method in different ways. Although I have provided the results of CAPM as a comparison and not as a check, it does have several disadvantages and should not be given comparable weight to the DCF method.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent impact of the coronavirus on economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[3] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough

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[3] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, 18 Feb 1992: *nytimes.com* Web. 23 Mar 2016.

to invalidate the way it is used in applications."[4] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults listed above. Additionally, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

Q. ARE THERE ANY RECENT COMMISSION ORDERS THAT DEVIATE FROM THE USE OF THE DCF AS THE PRIMARY METHOD IN DETERMINING A COMPANY'S RETURN ON EQUITY?

A. Yes. The Commission indicated in the most recent Aqua Pennsylvania, Inc.

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[4] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

(Aqua) base rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[5] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…"[6] , which deviates from prior Commission practice of primarily relying on the DCF.

Q. SHOULD THE COMMISSION'S USE OF THE CAPM AS A CEILING FOR A "RANGE OF REASONABLENESS" APPLY IN THIS PROCEEDING?

A. No. In a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[7] Aqua's return on equity of 10.00% is stated as being above the national average for water utility base rate cases and above the Distribution System Improvement Charge (DSIC) authorized by the Commission of 9.80%[8] for water and wastewater utilities based on a period ended September 30, 2021, and this DSIC rate is still in effect as the Commission has not published DSIC rates since this report was made public in January 2022. The above referenced report also states that the average return on equity for water utility base rate cases that have been completed during the first four months of

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[5] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

[6] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

[7] Regulatory Research Associates, "Commission authorizes management performance bonus for Aqua Pennsylvania," *S&P Global Market Intelligence*, May 16, 2022.

[8] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2021, approved at Public Meeting on January 13, 2022 at Docket No. M-2021-3030045.

2022 was 9.63% and for the last twelve months ended April 30, 2022 was 9.53% which are well below the 10.00% return on equity authorized by the Commission for Aqua. Although this is related to the water utility industry, it demonstrates the problem associated with using the CAPM as a ceiling for determining a utility's return on equity.

Additionally, as I explained above, the CAPM should not be used as a primary method and it should only be used as a comparison and not as a check of the DCF due to the concerns I stated above. Also, as demonstrated below, the use of the CAPM in this proceeding would result in a significant burden to ratepayers during a time of increasing levels of inflation and economic decline. Therefore, I disagree with providing the CAPM comparable weight to the DCF method.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul used the DCF, CAPM, RP, and CE methods in analyzing the Company's cost of equity. He made several adjustments to his results, which include consideration for size, various claimed risk factors, leverage, and management performance. Ultimately, Mr. Moul opined that a cost of equity of 11.20% is warranted (Columbia Statement No. 8, p. 6, line 5 through p. 7, line 8 and Columbia Exhibit No. 400, Schedule 1, p. 2).

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR COLUMBIA?

A. Based upon my analysis, I recommend a cost of common equity of 9.61% (I&E Exhibit No. 2, Schedule 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained above, I used my CAPM result only to present to the Commission a comparison and not as a check to my DCF results. My DCF analysis uses a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts.

DISCOUNTED CASH FLOW

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group (I&E Exhibit No. 2, Schedule 6):

Six-Company Proxy Group	Dividend Yield
Spot	2.91%
52-week average	3.23%
Average	3.07%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected growth rate estimates from Value Line, Yahoo! Finance, Zacks, and Morningstar.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for the six-company proxy group ranged from 2.90% to 10.50% with an overall average of 6.54% (I&E Exhibit No. 2, Schedule 7).

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows (I&E Exhibit No. 2, Schedule 8):

K	=	D_1/P_0	+	g
9.61%	=	3.07%	+	6.54%

Q. DOES THE DCF ADEQUATELY FACTOR IN RECENT INFLATIONARY TRENDS?

A. Yes. My DCF calculation includes a spot stock price when determining the dividend yield and analysts who generate forecasted earnings growth rates almost certainly take inflation into consideration as well, therefore, it contains the most up-to-date projected information of any model. Therefore, any potential concerns that the Commission should consider the overall economic climate and related inflation when deciding the merits of the Company's requested base rate increase are adequately covered by use of the DCF as a primary model for determining an appropriate return on equity.

CAPITAL ASSET PRICING MODEL

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the market.

Q. HOW DID YOU DETERMINE BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group of six gas companies, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.82 (I&E Exhibit No. 2, Schedule 9).

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I used the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I used the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has recently recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[9]

The forecasted yield on the 10-year Treasury Note, as can be seen in Blue Chip Financial Forecasts, is expected to be between 2.60% and 3.10% from the third quarter of 2022 through the third quarter of 2023, and it is forecasted to be 2.90% from 2023-2027. For my forecasted CAPM analysis, I used 2.88%, which is the average of all the yield forecasts I observed (I&E Exhibit No. 2, Schedule 10).

Q. HOW DID YOU DETERMINE THE RETURN ON THE OVERALL STOCK MARKET IN YOUR FORECASTED CAPM ANALYSIS?

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1700 stocks and the S&P 500. Value Line expects its universe of 1700 stocks to have an average yearly return of 12.57% over the next three to five years based on a forecasted dividend yield of 1.90% and a yearly index appreciation of 50%. The S&P 500 index is expected to have an average yearly return of 15.78% over the next five years based upon Barron's forecasted dividend yield of 1.38% and Morningstar's average expected increase in the S&P 500 index of 14.30% (I&E Exhibit No. 2, Schedule 11).

[9] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

Q. WHAT IS THE EXPECTED RETURN ON THE OVERALL STOCK MARKET BASED ON YOUR FORECASTED ANALYSIS?

A. The expected return on the overall market is 14.17% for my forecasted analysis (I&E Exhibit No. 2, Schedule 11).

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows (I&E Exhibit No. 2, Schedule 12):

$$K \quad = \quad R_f \quad + \quad \beta(R_m - R_f)$$

$$12.14\% = 2.88\% + 0.82\ (14.17\% - 2.88\%)$$

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed earlier in my testimony, my recommended cost of equity is primarily based upon my DCF analysis. I only present a CAPM analysis to the Commission as a comparison and not for recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific. Again, it has traditionally been the preference of the Commission to view both the DCF and CAPM analysis in base rate proceedings.

Q. IS IT NECESSARY OR APPROPRIATE TO APPLY THE CAPM WITH SIMILAR WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method in determining an appropriate return on equity sufficiently takes this into consideration. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth almost certainly take inflation into consideration as well, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 253 BASIS POINTS TO THE COST OF EQUITY BASED ON THE DIFFERENCE IN RESULTS BETWEEN YOUR CAPM ANALYSIS (12.14%) AND YOUR DCF ANALYSIS (9.61%)?

A. The example below illustrates the impact of 253 additional basis points to the Company's cost of equity if the results of my CAPM analysis were applied to the Company's filed rate base used rather than my DCF results:

Columbia Gas of Pennsylvania, Inc.

Claimed Equity Percentage of Capital Structure	54.38%
Difference in Rate on Equity between I&E CAPM and DCF Analysis (12.14% - 9.61% = 2.53%)	2.53%
Additional Basis Points to Calculated Cost of Equity	253
Claimed Rate Base*	$2,958,295,013
Impact Prior to Gross Revenue Conversion Factor (0.5438 x 0.0253 x $2,958,295,013)	**$40,700,637**
Gross Revenue Conversation Factor**	1.42417301
Total Impact (1.42417301 x $57,964,749)	**$57,964,749**

*(Columbia Exhibit 102, Schedule 3, p. 3)
** (Columbia Exhibit No. 102, Schedule 3, p. 5)

In this example, an addition of 253 basis points to the cost of equity would burden ratepayers to fund an additional amount of $57,964,749. In short, I believe it is inappropriate to use the CAPM as the top end of a range in determining a return on equity and any amount granted above the DCF (9.61% based on my recommendation) places an inappropriate burden on ratepayers, particularly given Columbia's projected frequency for future base rate cases and the increased funding for pipeline replacement as discussed in more detail by I&E witness Dusyant Patel (I&E Statement No. 1).

<u>CRITIQUE OF MR. MOUL'S PROPOSED COST OF EQUITY</u>

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. Moul's proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of Mr. Moul's CAPM, RP, and CE analyses in his recommendation. Second, I disagree with certain aspects of Mr. Moul's discussion of Columbia's risk. Third, I disagree with his application of the DCF including the forecasted growth rate and leverage adjustment he uses. Finally, I disagree with his inclusion of a size adjustment, his reliance on the 30-year Treasury Bond for his risk-free rate, and the use of a double-adjusted beta in his CAPM analysis. Finally, Mr. Moul's request for an additional 25 basis points for "strong management performance" is unjustified.

<u>WEIGHTS GIVEN TO THE CAPM, RP, AND CE METHODS</u>

Q. DO YOU AGREE WITH MR. MOUL'S RELIANCE ON THE CAPM AND RP MODELS?

A. No. While I am not opposed to providing the Commission the results of the CAPM for a point of comparison to the results of the DCF calculation, I am opposed to giving the CAPM and RP considerable weight. For the reasons discussed above, it is not appropriate to give the CAPM and RP models similar weight to the DCF as Mr. Moul has done in creating his recommended cost of equity range (Columbia Statement No. 8, p. 6, line 10). As discussed above, the

CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM, it suffers these same flaws.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF THE CE METHOD?

A. No. The companies in Mr. Moul's analysis are not utilities, and, therefore, they are too dissimilar to be used in a CE analysis. The companies in Mr. Moul's CE proxy group are simply not comparable to gas utilities in terms of their business risk or financial risk profile. Natural gas distribution companies are monopolies, which are subject to very little competition, if any. Due to this minimal competition, utilities in general have very low business risk and are able to maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. Moul's CE proxy group operate in an unregulated competitive environment with a higher level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage. Furthermore, in his CE analysis, Mr. Moul stated, "I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach" (Columbia Statement No. 8, p. 44, lines 5-7). It is my opinion the arbitrary use of 20% is unjustified as I am unaware of any gas utility company that has been awarded or regularly earns a 20% return.

RISK ANALYSIS

Q. SUMMARIZE MR. MOUL'S CLAIMS REGARDING RISK FACTORS THE COMPANY FACES.

A. Mr. Moul described the Company's claimed risk factors in two different sub-sections. In the first section, labeled "Natural Gas Risk Factors," he described the *qualitative* risk factors. In this section, Mr. Moul discussed the potential for bypass, the Company's construction program, the potential discontinuation of the Company's weather normalization adjustment (WNA) tariff design and/or the refusal of its revenue normalization adjustment (RNA) proposal (Columbia Statement No. 8, p. 7, line 9 through p. 12, line 2). In the second section of his risk analysis, labeled "Fundamental Risk Analysis," he described the *quantitative* risk factors. In this section, Mr. Moul discussed the Company's credit quality, as well as many different financial metrics including size, market ratios, common equity ratio, return on book equity, operating ratios, pre-tax interest coverage, quality of earnings, internally generated funds, and betas (Columbia Statement No. 8, p. 12, line 3 through p. 17, line 16).

Q. WHAT HAS MR. MOUL CLAIMED REGARDING THE POTENTIAL RISK OF BYPASS?

A. Mr. Moul opined that the Company faces a unique situation in Western Pennsylvania where gas utilities have overlapping territories; this creates "gas on gas" competition. He stated that one customer left the Company's system in the

Spring of 2019 and switched to another local distribution company (LDC) that overlaps the Company's service territory. He claimed that the six interstate pipelines traversing the Company's service territory create the potential for bypass among certain large volume customers. Additionally, Mr. Moul claimed that local gas production provides another bypass threat, as well as the consolidation of competing LDCs which form a strong competitor (Columbia Statement No. 8, p. 7, line 22 through p. 8, line 11).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMED RISK OF BYPASS FOR COLUMBIA?

A. The Western Pennsylvania market is unique in that the overlapping territories create "gas on gas" competition; however, whatever competition exists is limited to a very small number of competitors and only in overlapping territories. Mr. Moul did not provide the number of potential customers affected, nor did he quantify the impact of the one customer that left the Company's system or reveal the size of Columbia's territory that is overlapped by NGDC competitors. Just for a point of context, Columbia witness Kevin L. Johnson identified a total of 445,908 Columbia Gas customers in developing his customer count allocation factor (Columbia Statement No. 6, Exhibit KLJ-2, p. 5). Losing only one customer in 2019 to "gas on gas" competition does not seem to support Mr. Moul's contention that this is a substantive risk factor for the Company. Additionally, to the degree that customers must absorb switching costs to move from one NGDC to another, competition will be discouraged. Because insufficient information has been provided, the risk of bypass in overlapping territories cannot be substantiated. Beyond the claimed risk of bypass resulting from overlapping territories of competitors, Columbia faces no more risk than any of the companies in the proxy group. The cost of equity measured by the proxy group adequately compensates investors for the risk of bypass.

Q. WHAT CLAIM HAS MR. MOUL MADE REGARDING THE COMPANY'S RISK OF EXPOSURE IN REPLACING AGING INFRASTRUCTURE?

A. Mr. Moul claimed that the Company incurs additional risk because required capital expenditures to replace aging infrastructure do not increase the Company's customer base (Columbia Statement No. 8, p. 10, lines 21-23). The Company anticipates total capital expenditures over the next five years will equal 77% of the net utility plant in service as of December 31, 2021 (Columbia Statement No. 8, p. 11, lines 5-7).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S RISK CAUSED BY THE REPLACEMENT OF AGING INFRASTRUCTURE?

A. Every gas utility faces the same issues of upgrading or replacing its infrastructure. As costs for replacing infrastructure increase, Columbia, like any other regulated gas utility, has the option to file a base rate case at any time to address revenue inadequacy due to increasing costs, infrastructure replacement, or any other associated issues. Base rate cases allow a utility to recover its costs and provide it with the *opportunity* to earn a reasonable return on capital investments. Additionally, as Mr. Moul states in his testimony, the Commission offers risk reducing mechanisms such as the DSIC and the FPFTY to help reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures (Columbia Statement No. 8, p. 9, lines 10-19). It should be noted that these mechanisms were not designed to eliminate the need for periodic base rate case filings.

Q. WHAT RISK HAS MR. MOUL CLAIMED WITH RESPECT TO THE POTENTIAL DISCONTINUATION OF THE WEATHER NORMALIZATION ADJUSTMENT MECHANISM AND REFUSAL OF THE REVENUE NORMALIZATION ADJUSTMENT?

A. Mr. Moul stated that, "All of my Gas Group companies have some form of WNA mechanism, and in some cases, other forms of revenue decoupling. Therefore, the market prices of all companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism" (Columbia Statement No. 8, p. 9, lines 1-4). Mr. Moul further stated, "If the Company is unable to obtain the RNA mechanism, its risk will increase above that of the Gas Group that serves as a basis to measure the Company's cost of equity..." (Columbia Statement No. 8, p. 9, lines 6-9).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S INCREASED RISK AS A RESULT OF DISCONTINUING THE WNA MECHANISM?

A. The Commission allows utilities the opportunity to propose alternative ratemaking mechanisms, and Columbia has requested continuation of its WNA, albeit with modification, and proposed an RNA in this proceeding. I am not aware of any reason the WNA mechanism cannot be renewed. The Company currently does not have an RNA mechanism in place; therefore, its refusal will not increase risk to the Company. However, if the Commission approves the Company's RNA proposal, its overall risk will decrease as a result. I&E's position on Columbia's specific requests regarding the WNA and RNA proposals are addressed in the testimony of I&E witness Cline in I&E Statement No. 3. Further, Mr. Moul has not produced evidence demonstrating that the Gas Group companies employ either the WNA mechanism that is already authorized for Columbia, or the RNA mechanism that Columbia has proposed.

Q. WHAT HAS MR. MOUL CLAIMED REGARDING QUANTITATIVE RISK FACTORS IN THE SECTION LABELED "FUNDAMENTAL RISK ANALYSIS?"

A. Mr. Moul stated that it is necessary to establish a company's relative risk position within its industry through an analysis of quantitative and qualitative factors. Mr.

Moul used various financial metrics to compare Columbia to the S&P Public Utilities Index and his Gas Group (Columbia Statement No. 8, p. 12, lines 4-13).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S "FUNDAMENTAL RISK ANALYSIS?"

A. Two of the points he discussed, size risk and betas, have been discussed and disputed elsewhere in my direct testimony. Throughout the remainder of his "fundamental risk analysis," Mr. Moul made several statements to indicate that the Company has no more of a risk than any other company in his Gas Group. First, regarding operating ratios, Mr. Moul stated, "The five-year average operating ratios were 73.7% for the Company, 83.6% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were lower than the Gas Group, thereby indicating lower risk." (Columbia Statement No. 8, p. 15, lines 16-18). Second, concerning coverage, he stated, "Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.20 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk" (Columbia Statement No. 8, p. 15, line 23 through p. 16, line 4). Third, concerning internally generated funds, he stated, "Historically, the five-year average percentage of IGF to capital expenditures was 61.1% for the Company, 56.0% for the Gas Group and 69.5% for the S&P Utilities. Had the Company paid dividends in recent years, its

IGF would have been weaker. The Company's average IGF to construction percentage has been slightly stronger than the Gas Group, which can be traced to the lack of dividend payments by the Company" (Columbia Statement No. 8, p. 16, lines 14-19). Finally, concerning betas, he stated, "A comparison of market risk is shown by the Value Line beta of 0.88 as the average for the Gas Group and 0.91 as the average for the S&P Public Utilities. The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities" (Columbia Statement No. 8, p. 17, lines 5-9).

While some measures Mr. Moul discussed may imply a higher risk profile for the Company, he provided other more convincing measures that illustrate the Company has lower risk. Overall, through his own analysis and testimony, Mr. Moul substantiated that the Company has very similar risk as compared to that of his Gas Group.

COST OF EQUITY ADJUSTMENTS

INFLATED GROWTH RATES USED IN DCF ANALYSIS

Q. WHAT GROWTH RATE HAS MR. MOUL USED IN HIS DCF ANALYSIS?

A. Mr. Moul used a growth rate of 6.75% (Columbia Statement No. 8, p. 32, line 22).

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul stated, "Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.17%), Zacks (5.94%), and Value Line (7.61%)." (Columbia Statement No. 8, p. 27, lines 6-7). The average of the growth rates from Mr. Moul's sources resulted in an average growth rate of 6.24% ((5.17% + 5.94% + 7.61%) ÷ 3); however, Mr. Moul used a growth rate of 6.75% in his DCF analysis. Mr. Moul stated that growth rates should not be established by a mathematical formulation and his growth rate is reasonable as it is supported by continued infrastructure spending (Columbia Statement No. 8, p. 28, lines 1-8).

Q. DO YOU AGREE WITH MR. MOUL'S GROWTH RATE ANALYSIS?

A. No. I disagree with Mr. Moul's belief that DCF growth rates *should not* be established by mathematical formulation, I believe that any alternative is subjective and introduces additional and unnecessary bias and should be avoided whenever possible. The use of a higher growth rate than the average of his proxy group ignores the fact that analysts making earnings per share growth forecasts are already aware of the economic conditions and the state of the gas utility industry. The reasons Mr. Moul has given for choosing a growth rate above his calculated average are factors that are already included in the earnings per share growth forecasts. Therefore, choosing a growth rate higher than the average of his proxy group would account for the same factors twice.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE RESULTS OF MR. MOUL'S PROJECTED GROWTH RATES?

A. Yes. While the five-year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature. An article written by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong support of earnings forecasts being higher than actual earnings.[10] In spring of 2010, McKinsey on Finance presented an article reporting that after a decade of stricter regulation analysts' forecasts are still overly optimistic.[11]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

In summary, since analysts' projected growth forecasts are most often overly optimistic, there is no need to arbitrarily and non-formulaically increase the estimates used in a DCF analysis.

[10] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67.

[11] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey On Finance Number 35 Spring 2010, pp. 14-17.

LEVERAGE ADJUSTMENT APPLIED TO DCF ANALYSIS

Q. HAS MR. MOUL MADE ANY ADDITIONAL ADJUSTMENTS TO THE RESULT OF HIS DCF ANALYSIS?

A. Yes. Mr. Moul proposed a 99-basis point "leverage" adjustment to the results of his DCF analysis to account for applying a market-determined cost of equity to a book value capital structure (Columbia Statement No. 8, p. 32, lines 9-12).

Q. WHAT IS FINANCIAL LEVERAGE?

A. Financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered to be highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK (M/B) RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value by comparing the market value and book value of a company's equity. One way of doing this is to divide the current price per share of stock by the book value per share. A M/B result of above one (1) is desired.

Q. HAS MR. MOUL PROPOSED TO ADJUST THE RESULT OF HIS DCF ANALYSIS TO RECOGNIZE HOW THE COMPANY IS LEVERAGED?

A. No. Mr. Moul has not proposed to change the capital structure of the utility (a leverage adjustment), nor has he proposed to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul has proposed to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's equity. I am not aware of any term in academic journals, textbooks, or other literature that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. Mr. Moul stated that in order to make the DCF results relevant to a book value capital structure, the market-derived cost of equity needs to be adjusted to take into consideration the difference in financial risk (Columbia Statement No. 8, p. 29, lines 1-4). Mr. Moul opined this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt, and, therefore, less risk than book value capital structures (Columbia Statement No. 8, p. 28, lines 17-23).

Q. HOW HAS MR. MOUL ATTEMPTED TO JUSTIFY THE LEVERAGE ADJUSTMENT USED IN HIS ANALYSIS?

A. Mr. Moul simply states:

> I know of no means to mathematically solve for the 0.99% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.99% adjustment is merely a convenient way to compare the 11.42% return computed using the Modigliani & Miller formulas to the 10.43% return generated by the DCF model based on a market value capital structure.[12]

[12] Columbia Statement No. 8, p. 32, lines 2-7.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 99 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 99 additional basis points to the Company's cost of equity:

Columbia Gas of Pennsylvania, Inc.	
Claimed Equity Percentage of Capital Structure	54.38%
Additional Basis Points to Calculated Cost of Equity	99
Claimed Rate Base*	$2,958,295,013
Impact Prior to Gross Revenue Conversion Factor (0.5438 x 0.0099 x $2,958,295,013)	**$15,926,336**
Gross Revenue Conversation Factor**	1.42417301
Total Impact (1.42417301 x $15,926,336)	**$22,681,858**

*(Columbia Exhibit 102, Schedule 3, p. 3)
** (Columbia Exhibit No. 102, Schedule 3, p. 5)

In this example, an addition of 99 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $22,681,858.

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT" JUSTIFICATION?

A. No. Mr. Moul's adjustment is inappropriate for a couple of reasons, including the characterization of financial risk and Commission precedent.

Q. EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies' use a company's financial statements for their analysis, not market capital structure. The income statement reflects the financial risk of a company because it represents the performance of the company over a certain period of time. A change in the market value of the stock is not reflected in the income statement nor is a change in market value capital structure reflected in the book value capital structure unless treasury stock is purchased. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure that is relied upon in an analysis such as that done by rating agencies.

Q. HAS THE COMMISSION REJECTED THE USE OF A LEVERAGE ADJUSTMENT?

A. Yes. The following five cases are the most recent instances where the Commission has rejected the use of a "leverage adjustment."

First, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, at Docket No. R-00072711 (Order Entered July 31, 2008), p. 38, the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases."

Second, in *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, at Docket No. R-2010-2179103 (Order Entered July 14, 2011), p. 79, the Commission agreed with the I&E position and stated, "any adjustment to the results of the market based DCF are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment."

Third, in *Pennsylvania Public Utility Commission, et al v. UGI Utilities, Inc. – Electric Division*, at Docket No. R-2017-2640058 (Order Entered October 25, 2018), pp. 93-94, the Commission agreed with the I&E position and stated, "we conclude that an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."

Fourth, in *Pennsylvania Public Utility Commission, et. al v. Columbia Gas of Pennsylvania, Inc.*, at Docket R-2020-3018835 (Order Entered February 19, 2021), pp. 137-141, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excludes the use of a leverage adjustment.

Fifth, in *Pennsylvania Public Utility Commission, et. al v. PECO Energy Company – Gas Division*, at Docket R-2020-3018929 (Order Entered June 22, 2021, Public Version), pp. 172-173, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded PECO's application of a leverage adjustment.

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et. al v. Aqua Pennsylvania, Inc.*, at Docket R-2021-3027385 (Order Entered June 22, 2021), pp. 154-155, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Aqua's application of a leverage adjustment.

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSED LEVERAGE ADJUSTMENT.

A. I recommend that Mr. Moul's proposed 99-basis point leverage adjustment be rejected because true financial risk is a function of the amount of interest expense, and capital structure information provided to investors through Value Line is that of book values, not market values. This demonstrates that investors base their decisions on book value debt and equity ratios for the regulated utilities, and therefore, no adjustment is needed. Mr. Moul's proposed adjustments serve only to manipulate the DCF's market-based methodology.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. MOUL'S DCF CALCULATION?

A. Yes. While I am not directly disputing Mr. Moul's adjusted dividend yields, it is important to recognize that, as cited above, the Commission has recently agreed with I&E's DCF methodology which includes the appropriate calculation of dividend yields. Although it is acceptable to adjust historical dividend yields as Mr. Moul has done, it is preferable to use forecasted dividends to calculate the dividend yields when available, such as the ones offered by Value Line that I have employed.

Q. WHAT WOULD MR. MOUL'S DCF BE WITHOUT ANY ADJUSTMENTS?

A. Without Mr. Moul's use of inflated growth rates and a leverage adjustment, his DCF would consist of his calculated dividend yield of 3.68% and an average growth rate of 6.24% as shown above results in a 9.92% cost of equity which is well below his claimed cost of equity of 11.20% and much closer to my recommended cost of equity of 9.61%.

<u>INFLATED BETAS USED IN CAPM ANALYSIS</u>

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul has used the same logic for inflating his CAPM betas from 0.88 to 1.00 that he used to enhance his DCF returns, through a financial risk or "leverage" adjustment (Columbia Statement No. 8, p. 37, line 17 through p. 38, line 12). Such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that enhancements are unwarranted for DCF results.

Also, if the unadjusted *Value Line* betas do not reflect an accurate investment risk as Mr. Moul contends, the question naturally arises as to why *Value Line* does not publish betas that are adjusted for leverage. Until this type of adjustment is demonstrated in the academic literature to be valid, such leverage adjusted betas in a CAPM model should be rejected. Furthermore, the Commission found no basis to add leverage adjusted betas in the most recent litigated Aqua Pennsylvania, Inc. base rate case.[13]

Finally, as described in my CAPM analysis above, a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.00 to the entire industry or gas proxy group is irrational.

<u>SIZE ADJUSTMENT APPLIED TO CAPM ANALYSIS</u>

Q. WHAT SIZE ADJUSTMENT HAS MR. MOUL PROPOSED?

A. Mr. Moul added 102 basis points to his CAPM indicated cost of common equity

[13] *Pa. PUC v. Aqua Pennsylvania, Inc.;* Docket No. R-2021-3027385 (Order Entered May 16, 2022). *See generally* Disposition of Leverage Adjustment and Management Performance, pp. 166-167.

because he opined that as the size of a firm decreases, its risk and required return increases (Columbia Statement No. 8, p. 40, lines 22-23). Mr. Moul relied upon technical literature including Morningstar's Stocks, Bonds, Bills, and Inflation Yearbook, a Fama and French study entitled "The Cross-Section of Expected Stock Returns," and an article published in Public Utilities Fortnightly entitled "Equity and the Small-Stock Effect" (Columbia Statement No. 8, p. 40, line 23 through p. 41, line 6).

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 102 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 102 additional basis points to the Company's cost of equity:

Columbia Gas of Pennsylvania, Inc.	
Claimed Equity Percentage of Capital Structure	54.38%
Additional Basis Points to Calculated Cost of Equity	102
Claimed Rate Base*	$2,958,295,013
Impact Prior to Gross Revenue Conversion Factor (0.5438 x 0.0102 x $2,958,295,013)	**$16,408,952**
Gross Revenue Conversation Factor**	1.42417301
Total Impact (1.42417301 x $16,408,952)	**$23,369,187**

*(Columbia Exhibit 102, Schedule 3, p. 3)
** (Columbia Exhibit No. 102, Schedule 3, p. 5)

In this example, an addition of 102 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $23,369,187.

Q. DO YOU AGREE WITH MR. MOUL'S SIZE ADJUSTMENT?

A. No. Mr. Moul's proposed size adjustment is unnecessary because the technical literature he cited supporting investment adjustments related to the size of a company is not specific to the utility industry; therefore, it has no relevance in this proceeding.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[14]

Columbia has presented no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article

[14] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected. Additionally, and more importantly, the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation.[15]

Q. WHAT WOULD MR. MOUL'S CAPM RESULT BE WITHOUT THE SIZE ADJUSTMENT AND INFLATED BETAS?

A. Mr. Moul's CAPM result would be 11.27% without his size adjustment and inflated betas which is 218 basis points lower than his originally calculated CAPM result of 13.45%. The calculation is repeated below without Mr. Moul's adjustments:

Rf	+	ß	*	(Rm-Rf)	+	size	=	K
2.75%	+	0.88	*	9.68%	+	0.00%	=	11.27%

<u>MANAGEMENT PERFORMANCE</u>

Q. WHAT IS THE COMPANY'S CLAIM REGARDING MANAGEMENT PERFORMANCE.

A. Mr. Moul explains that his 10.95% cost of equity recommendation includes 25 basis points in consideration of the Company's exemplary management performance (Columbia Statement No. 8, p. 6, line 16 through p. 7, line 1). The

[15] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100 and *Pa. PUC v. Aqua Pennsylvania, Inc.;* Docket No. R-2021-3027385 (Order Entered May 16, 2022). *See generally* Disposition of Leverage Adjustment and Management Performance, p. 154.

Company's rationale to support its management performance claim includes Columbia's management performance is demonstrated through among other things, its enhanced safety measures, accelerated infrastructure replacement plan, superior results in PUC Management Performance Audit and PUC UCARE reports, its PAR rate, Quality of Service Performance report, and its result in the 2021 J.D. Power Residential Customer Satisfaction Survey (Columbia Statement No. 1, p. 25, line 19 through p. 48, line 7).

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 25 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 25 additional basis points to the Company's cost of equity:

Columbia Gas of Pennsylvania, Inc.	
Claimed Equity Percentage of Capital Structure	54.38%
Additional Basis Points to Calculated Cost of Equity	25
Claimed Rate Base*	$2,958,295,013
Impact Prior to Gross Revenue Conversion Factor (0.5438 x 0.0025 x $2,958,295,013)	**$4,021,802**
Gross Revenue Conversation Factor**	1.42417301
Total Impact (1.42417301 x $4,021,802)	**$5,727,742**

*(Columbia Exhibit 102, Schedule 3, p. 3)
** (Columbia Exhibit No. 102, Schedule 3, p. 5)

In this example, an addition of 25 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $5,727,742.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING MANAGEMENT EFFECTIVENESS?

A. No. Although the Company touts its Management Audit scores against other NGDC's it is not to say that the Company does not have room for improvement. According to the Commission's most recent Management and Operations Audit for Columbia Gas of Pennsylvania, Inc. (issued in June 2020) at Docket No. D-2019-3011582, the following deficits are illustrated regarding Columbia's customer service:

- Page 53 – Columbia's metering and billing policies and procedures are outdated;
- Page 53 – Columbia's average arrearages were higher throughout the audit period compared to a panel average of Pennsylvania natural gas distribution companies;
- Page 56 – Columbia's revenue recovery has not developed net collection performance goals with which to manage its third-party collection efforts;
- Page 58 – NiSource Corporate Services Company does not have a documented theft of service program; and

- Page 58 – Columbia's customer service representative turnover is higher than at other like utilities.

Unlike other areas, customer service is an area of management and operations over which the Company has complete and direct control. By awarding the Company management effectiveness points, it will cost ratepayers money for service that can and should be improved. Any savings from effective operating and maintenance cost measures should flow through to ratepayers and/or investors. These claimed savings would likely be offset by the addition of basis points for management effectiveness as ratepayers would have to fund the additional costs. This defeats the purpose of cutting expenses to benefit ratepayers.

Q. ARE YOU AWARE OF ANY OTHER COMPANIES THAT HAVE RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. In the most recent litigated Aqua base rate case, the Commission awarded Aqua an addition of 25 basis points for its management performance efforts.[16] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. In this proceeding, the Commission stated the following: [17]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater

[16] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order entered May 16, 2022).

[17] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 169 (Order entered May 16, 2022).

> systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage.

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT COLUMBIA SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY?

A. No. The issuance of equity points to recognize management performance must always be done on a case-by-case basis. The situation in the Aqua case was very specific to the company rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to Columbia. Management performance is something that is very specific to each individual utility. Therefore, what the Commission has historically decided in this regard, and the management performance of other utilities, has no bearing on whether Columbia should receive a higher return on equity to recognize its management performance.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF 25 ADDITIONAL BASIS POINTS FOR THE COMPANY'S MANAGEMENT PERFORMANCE?

A. Ultimately, for any company, true management effectiveness is earning a higher return through its efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders. Columbia, or any utility should not be awarded additional basis points for doing what they are required to do in order to provide adequate, efficient, safe, and reasonable service under 66 Pa C.S.A. §1501 especially when compared to the reasons stated above by the Commission for Aqua being awarded management performance points.

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANY'S PROPOSED OVERALL RATE OF RETURN?

A. The Company's proposed overall rate of return is 8.08% (Columbia Statement No. 8, p. 2, line 5).

Q. WHAT IS I&E'S RECOMMENDED OVERALL RATE OF RETURN?

A. I recommend an overall rate of return for the Company of 7.22% (I&E Exhibit No. 2, Schedule 1).

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. First, a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[18] illustrates that Columbia Gas of Pennsylvania,

[18] Regulatory Research Associates, "Major energy utility cases in progress in the US, Quarterly update on pending rate cases," *S&P Global Market Intelligence*, March 16, 2022.

Inc.'s 11.20% requested return on equity is a significant 99 basis points higher than the average return on equity request of 10.21% of all pending nationwide gas utility rate cases as of March 10, 2022. It is also important to note here that Pennsylvania is a deregulated state, which would indicate less risk.

Second, when asked, Mr. Moul indicated he was unaware if any natural gas distribution utilities throughout the United States were granted a Commission authorized return of 11.20% or higher cost of common equity in the past two years (I&E Exhibit No. 2, Schedule 13).

Third, the Company's requested return on common equity is 100 basis points higher than the Commission's approved DSIC rate of 10.20% (Q3 2021 Quarterly Earnings Summary Report) for gas distribution companies. My understanding is the DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring the existing aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning." As such, the DSIC rate does not serve as a proper measurement of a subject utility's cost of equity in a rate case proceeding. To suggest the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest.

Finally, while I am aware of the rising costs of capital due to the after-effects of the pandemic and the increasing levels of inflation, I believe it is important not to over burden ratepayers. While the economy is in decline, Columbia is requesting a record return on equity to apply to its equity heavy capital structure. As detailed in the various charts above, the effect of Mr. Moul's adjustments to the market-determined cost of common equity are an enormous burden to ratepayers and are completely unwarranted and unnecessary. Although they are not cumulative, the impact to ratepayers of each of the disputed adjustments is summarized as follows:

Adjustment	Total Impact
Leverage Adjustment	$22,681,858
Size Adjustment	$23,369,187
Management Adjustment	$5,727,742

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Christopher Keller

PROFESSIONAL AND EDUCATIONAL BACKGROUND

EXPERIENCE

- Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
  January 2014 to Present
  Fixed Utility Financial Analyst, Bureau of Investigation & Enforcement

- Pennsylvania Insurance Department, Harrisburg, Pennsylvania
  September 2008 to January 2014
  Insurance Company Financial Analyst, Bureau of Licensing & Financial Analysis

EDUCATION AND TRAINING

- FAI Utility, Boston, MA
  -Finance and Accounting for Financial Professionals
  May 21-23, 2014

- York College of Pennsylvania, York, Pennsylvania
  -Master of Business Administration, Finance Concentration
  2008
  -Bachelor of Science, Accounting,
  2006

TESTIMONY SUBMITTED IN THE FOLLOWING CASES

- A-2021-3026132 – Aqua Pennsylvania Wastewater, Inc. – Acquisition of the Wastewater Collection and Conveyance System Assets of East Whiteland Township (1329)
- P-2021-3030012 – Metropolitan Edison Company (DSP)
- P-2021-3030013 – Pennsylvania Electric Company (DSP)
- P-2021-3030014 – Pennsylvania Power Company (DSP)
- P-2021-3030021 – West Penn Power Company (DSP)
- R-2021-3026116 – Borough of Hanover – Water (ROR)
- R-2021-3025206 – Community Utilities of Pennsylvania – Water Division (ROR)
- R-2021-3025207 – Community Utilities of Pennsylvania – Wastewater Division (ROR)
- R-2021-3025652 – UGI Utilities, Inc. – Gas Division (1307(f))
- R-2021-3024750 – Duquesne Light Company (O&M and ROR)
- R-2021-3024296 – Columbia Gas of Pennsylvania, Inc. (ROR)
- R-2020-3018929 – PECO Energy Company – Gas Division (ROR)

TESTIMONY SUBMITTED (CONTINUED)

- P-2020-3020914 – Twin Lakes Utilities, Inc. (529 Proceeding)
- R-2020-3018835 – Columbia Gas of Pennsylvania, Inc. (ROR)
- R-2020-3019680 – UGI Utilities, Inc. (1307(f))
- P-2020-3019356 – PPL Electric Utilities Corporation (DSP)
- R-2019-3015162 – UGI Utilities, Inc. – Gas Division (ROR)
- R-2019-3010955 – City of Lancaster – Sewer Fund (O&M)
- R-2019-3009647 – UGI Utilities, Inc. – Gas Division (1307(f))
- R-2018-3006818 – Peoples Natural Gas Company LLC (O&M)
- R-2018-3000124 – Duquesne Light Company (O&M)
- R-2018-3001631 – UGI Central Penn Gas, Inc. (1307(f))
- R-2018-3001632 – UGI Penn Natural Gas, Inc. (1307(f))
- R-2018-3001633 – UGI Utilities, Inc. (1307(f))
- R-2018-2645938 – Philadelphia Gas Works (1307(f))
- P-2017-2637855 – Metropolitan Edison Company (DSP)
- P-2017-2637857 – Pennsylvania Electric Company (DSP)
- P-2017-2637858 – Pennsylvania Power Company (DSP)
- P-2017-2637866 – West Penn Power Company (DSP)
- R-2017-2602627 – UGI Central Penn Gas, Inc. (1307(f))
- R-2017-2602638 – UGI Utilities, Inc. (1307(f))
- R-2017-2586783 – Philadelphia Gas Works (O&M)
- R-2017-2587526 – Philadelphia Gas Works (1307(f))
- I-2016-2526085 – Delaware Sewer Company (529 Proceeding)
- R-2016-2531550 – Citizens' Electric Company (O&M)
- R-2016-2531551 – Wellsboro Electric Company (O&M)
- R-2016-2537349 – Metropolitan Edison Company (CWC and CAP)
- R-2016-2537352 – Pennsylvania Electric Company (CWC and CAP)
- R-2016-2537355 – Pennsylvania Power Company (CWC and CAP)
- R-2016-2537359 – West Penn Power Company (CWC and CAP)
- R-2016-2543311 – UGI Central Penn Gas, Inc. (1307(f))
- R-2015-2518438 – UGI Utilities, Inc. – Gas Division (CWC and USP)
- P-2015-2511333 – Metropolitan Edison Company (DSP)
- P-2015-2511351 – Pennsylvania Electric Company (DSP)
- P-2015-2511355 – Pennsylvania Power Company (DSP)
- P-2015-2511356 – West Penn Power Company (DSP)
- R-2015-2468056 – Columbia Gas of Pennsylvania, Inc. (O&M)
- P-2014-2404341 – Delaware Sewer Company (529 Investigation)
- R-2014-2452705 – Delaware Sewer Company (O&M)
- R-2014-2428304 – Borough of Hanover – Water (O&M)
- R-2014-2419774 – Wellsboro Electric Company (Customer Choice Support Charge)
- R-2014-2420279 – UGI Central Penn Gas, Inc. (1307(f))

ASSISTED WITH THE FOLLOWING CASES (Testimony not Required)

- R-2017-2631441 – Reynolds Water Company (ROR)
- R-2016-2580030 – UGI Penn Natural Gas, Inc. (ROR)
- R-2014-2462723 – United Water Pennsylvania (CWC)
- R-2014-2428742 – West Penn Power Company (CWC)
- R-2014-2428743 – Pennsylvania Electric Company (CWC)
- R-2014-2428744 – Pennsylvania Power Company (CWC)
- R-2014-2428745 – Metropolitan Edison Company (CWC)
- R-2013-2397353 – Pike County Light & Power Company (Gas) (O&M)
- R-2013-2397237 – Pike County Light & Power Company (Electric) (O&M)

I&E Exhibit No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
	Columbia Gas of Pennsylvania, Inc.		
Long Term Debt	43.23%	4.51%	1.95%
Short-Term Debt	2.39%	1.65%	0.04%
Common Equity	54.38%	9.61%	5.23%
Total	100.00%		7.22%

Proxy Group Capital Structure

	2021		2020		2019		2018		2017		Average
Atmos Energy Corp											
Long-term Debt	$ 5,124.950	39.33%	$ 4,732.850	41.07%	$ 3,529.452	36.22%	$ 2,493.665	31.81%	$ 3,067.045	41.37%	37.96%
Short-term Debt	-	0.00%	-	0.00%	464.915	4.77%	575.780	7.34%	447.745	6.04%	3.63%
Common Equity	7,906.889	60.67%	6,791.203	58.93%	5,750.223	59.01%	4,769.950	60.85%	3,898.666	52.59%	58.41%
	13,031.839	100.00%	11,524.053	100.00%	9,744.590	100.00%	7,839.395	100.00%	7,413.456	100.00%	100.00%
Chesapeake Utilities											
Long-term Debt	558.474	35.93%	518.371	37.26%	450.064	35.75%	316.020	27.99%	197.395	21.12%	31.61%
Short-term Debt	221.634	14.26%	175.644	12.63%	247.371	19.65%	294.458	26.08%	250.969	26.85%	19.89%
Common Equity	774.130	49.81%	697.085	50.11%	561.577	44.60%	518.439	45.92%	486.294	52.03%	48.50%
	1,554.238	100.00%	1,391.100	100.00%	1,259.012	100.00%	1,128.917	100.00%	934.658	100.00%	100.00%
Nisource Inc											
Long-term Debt	9,211.300	60.71%	9,249.700	63.25%	7,907.800	53.48%	7,105.400	50.92%	7,512.200	57.62%	57.19%
Short-term Debt	560.000	3.69%	503.000	3.44%	1,773.200	11.99%	1,977.200	14.17%	1,205.700	9.25%	8.51%
Common Equity	5,400.800	35.60%	4,872.200	33.31%	5,106.700	34.53%	4,870.900	34.91%	4,320.100	33.13%	34.30%
	15,172.100	100.00%	14,624.900	100.00%	14,787.700	100.00%	13,953.500	100.00%	13,038.000	100.00%	100.00%
Northwest Natural Gas Co											
Long-term Debt	1,124.055	45.90%	940.702	44.08%	806.796	44.28%	706.247	41.88%	683.184	46.16%	44.46%
Short-term Debt	389.500	15.91%	304.525	14.27%	149.100	8.18%	217.620	12.90%	54.200	3.66%	10.99%
Common Equity	935.146	38.19%	888.733	41.65%	865.999	47.53%	762.634	45.22%	742.776	50.18%	44.55%
	2,448.701	100.00%	2,133.960	100.00%	1,821.895	100.00%	1,686.501	100.00%	1,480.160	100.00%	100.00%
One Gas Inc.											
Long-term Debt	3,707.778	56.60%	1,613.228	37.83%	1,314.064	33.18%	1,285.483	35.44%	1,193.257	33.99%	39.41%
Short-term Debt	494.000	7.54%	418.225	9.81%	516.500	13.04%	299.500	8.26%	357.215	10.18%	9.76%
Common Equity	2,349.532	35.86%	2,233.311	52.37%	2,129.390	53.77%	2,042.656	56.31%	1,960.209	55.84%	50.83%
	6,551.310	100.00%	4,264.764	100.00%	3,959.954	100.00%	3,627.639	100.00%	3,510.681	100.00%	100.00%
Spire Inc.											
Long-term Debt	2,992.800	49.22%	2,482.100	45.88%	2,082.600	40.62%	1,900.100	40.35%	1,995.000	44.69%	44.15%
Short-term Debt	672.000	11.05%	648.000	11.98%	743.200	14.50%	553.600	11.76%	477.300	10.69%	11.99%
Common Equity	2,416.200	39.73%	2,280.300	42.15%	2,301.000	44.88%	2,255.400	47.89%	1,991.300	44.61%	43.85%
	6,081.000	100.00%	5,410.400	100.00%	5,126.800	100.00%	4,709.100	100.00%	4,463.600	100.00%	100.00%

Five-Year Average Capital Structure	
Long-term Debt	42.46%
Short-term Debt	10.80%
Common Equity	46.74%
	100.00%

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Accessed on May 2, 2022

	2021 Interest Charges	Long-term Debt	Debt Cost
Atmos Energy Corp	94.97	5,124.95	1.85%
Chesapeake Utilities	19.57	558.47	3.50%
Nisource Inc	345.70	9,211.30	3.75%
Northwest Natural Gas Co	44.49	1,124.06	3.96%
One Gas Inc.	64.50	3,707.78	1.74%
Spire Inc.	111.00	2,992.80	3.71%
	Range:	**Low**	**1.74%**
		High	**3.96%**
		Average	**3.09%**

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Accessed on May 2, 2022

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. I & E RR-003-D:

Reference Columbia Statement No. 8, page 20, lines 1-4 concerning the short-term debt cost rate:

A. Provide the source of the 1.35% LIBOR rate used to calculate the short-term debt cost rate.

B. Provide the calculation and explanation of the 30-basis point spread used to calculate the short-term debt cost rate.

Response:

A. As a preliminary matter, there is no reference to a 1.35% LIBOR rate on page 20 of Columbia Statement No. 8. Please refer to Attachment A to this response that shows that a LIBOR rate of 1.47% was used for this case.

B. Upon review of Columbia Statement No. 8, it was discovered that there is a typo on page 20. The correct spread over the LIBOR rate is 0.20%. An errata will be filed to correct the typo in my testimony. See Attachment A for the components of the 1.65% cost rate for short-term debt for the FPFTY. Attachment A shows the calculation of the 20-basis point spread. The 20-basis point spread was derived by looking at the average spread between actual commercial paper rate and 3M LIBOR during 2019-2021.

	2022 Short-Term Borrowing Rate					2023 Short-Term Borrowing Rate				
	3/31/22	6/30/22	9/30/22	12/31/22	Average	3/31/23	6/30/23	9/30/23	12/31/23	Average
3-Month Libor*	0.39%	0.62%	0.80%	1.01%	0.71%	1.17%	1.38%	1.60%	1.71%	1.47%
CP Spread**	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
All In Rate***	0.60%	0.80%	1.00%	1.20%	0.90%	1.35%	1.60%	1.80%	1.90%	1.65%

** Analyst projections from Bloomberg*

*** Average CP spread to 3 Month Libor from 2019-2021*

**** Rounded to the nearest 5 bps*

Enter # <GO> for details

Chart | Export | Disclaimer | Page 1/3 **Bond Yield Forecasts**

Region: G7 | Spread: 2 Year - 10 Year

	Rate	Mkt Yld	Q1 22	Q2 22	Q3 22	Q4 22	Q1 23	Q2 23	Q3 23	Q4 23	Q1 24	Q2 24
	United States											
1)	US 30-Year	2.07	2.19	2.35	2.44	2.52	2.59	2.65	2.71	2.77	2.98	3.06
2)	US 10-Year	1.73	1.81	1.95	2.05	2.13	2.20	2.29	2.36	2.44	2.59	2.67
3)	US 5-Year	1.51	1.50	1.62	1.71	1.80	1.89	1.99	2.06	2.13	2.23	2.32
4)	US 2-Year	0.96	0.92	1.09	1.26	1.40	1.53	1.66	1.77	1.87	1.99	2.09
5)	US 3-Month Libor	0.26	0.39	0.62	0.80	1.01	1.17	1.38	1.60	1.71	1.79	1.89
6)	Fed Funds Rate - Upper Bound	0.25	0.40	0.65	0.90	1.05	1.25	1.45	1.65	1.80	1.95	2.10
7)	Fed Funds Rate - Lower Bound	0.00	0.17	0.39	0.63	0.82	1.02	1.21	1.39	1.57	1.68	1.84
	2 Year - 10 Year Spread	0.78	0.89	0.86	0.79	0.74	0.67	0.63	0.58	0.57	0.60	0.58
	Germany											
8)	Germany 10-Year	-0.11	-0.06	0.02	0.07	0.11	0.17	0.24	0.31	0.36	0.49	0.57
9)	Germany 2-Year	-0.66	-0.59	-0.58	-0.56	-0.54	-0.48	-0.43	-0.38	-0.33	-0.27	-0.21
10)	3-Month Euribor	-0.55	-0.54	-0.53	-0.51	-0.49	-0.45	-0.43	-0.44	-0.35	-0.35	-0.27
11)	ECB Main Refinancing Rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05	0.10	0.15
12)	ECB Deposit Rate	-0.50	-0.50	-0.50	-0.50	-0.49	-0.47	-0.47	-0.43	-0.38	-0.29	-0.19
	2 Year - 10 Year Spread	0.55	0.53	0.60	0.63	0.65	0.65	0.67	0.69	0.69	0.77	0.78
	United Kingdom											
13)	UK 10-Year	1.12	1.18	1.30	1.36	1.43	1.48	1.56	1.56	1.61	1.83	1.88
14)	UK 2-Year	0.86	0.78	0.88	0.98	1.06	1.15	1.24	1.17	1.22	1.43	1.48
15)	UK 3-Month Libor	0.55	0.40	0.48	0.59	0.70	0.80	0.82	1.05	1.13	1.37	
16)	BOE Bank Rate	0.25	0.40	0.55	0.70	0.80	0.90	1.00	1.10	1.20	1.30	1.45
	2 Year - 10 Year Spread	0.26	0.41	0.43	0.38	0.37	0.33	0.33	0.39	0.38	0.41	0.40

Australia 61 2 9777 8600 Brazil 5511 2395 9000 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 4565 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000
SN 918028 EST GMT-5:00 H606-8248-2 24-Jan-2022 14:23:18

I&E Exhibit No. 2
Schedule 5
Page 1 of 2

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 40, No. 12, December 1, 2021

Wolters Kluwer

COVID Omicron Variant Confuses Outlook, Especially Accompanied by High Inflation

Over the Thanksgiving holiday, a new variant of the COVID virus was reported, especially in South Africa and Botswana. South African doctors indicate that it has very mild symptoms, so that people can generally be treated at home. The World Health Organization has designated this as the "Omicron" variant and describes it as a "variant of concern." So far, at this writing, no cases have been reported in the United States, although there are some nearby in Canada.

Holiday Period Generates Erratic Financial Market Moves, then Fed Chair Powel Testifies. The first reports of this variant set off strong movements in financial markets on Friday, November 26, the day after Thanksgiving. Because of the post-holiday atmosphere, trading volume was light, which meant that price movements may have been exaggerated. Erratic movements in Treasury rates and other fixed-income sectors continued. Then on November 30th, Federal Reserve Chairman Powell testified before a Congressional committee and suggested that the current high inflation might prompt the Fed to quicken the pace of its bond-purchase "tapering."

The Blue Chip Financial Forecasts survey for December was taken on November 22 and 23, that is, the Monday and Tuesday before Thanksgiving. During the subsequent market whipsaws, no participants have asked to alter their forecasts. This likely stands to reason in light of the absence of comprehensive and definitive information about the Omicron variant and the fact that, as of November 29, it has not spread within the United States.

The forecasts as submitted continue to reflect the current strong inflationary environment, exacerbated by the continuing supply-chain issues. Some of the latter are starting to ease, for instance, as container ships are now being charged fees if they leave containers on docks in California.

Growth Expected to Improve, Inflation to Moderate. The Blue Chip panel's projections for GDP growth envision a rebound this quarter to a 5.1% seasonally adjusted annual rate from the meager 2.1% in Q3. In early 2022, Q1 would see 4.4% and Q2 3.8% with the following three quarters averaging 2.8%. While inflation is expected to remain undesirably strong this quarter and next, the panel believes that it would moderate later in 2022, staying just slightly higher than in last month's forecast. The personal consumption expenditure price index rose at a 5.3% annualized pace in Q3 and the Blue Chip panel estimates it at 4.5% this quarter. In 2022, it would moderate from 2.9% in Q1 to 2.3% in Q4; the result for the year would be 2.5%, compared to 2.4% in the November forecast.

The panel's interest rate forecasts indicate that the higher-than-expected inflation might, as Fed Chair Powell hinted in his testimony, encourage the Fed to raise the federal funds rate somewhat earlier than they have been expecting. So the December forecast expects that the rate would start to climb in Q3 2022 rather than Q4. By Q1 2023, the rate would be 0.6%, compared with 0.4% in the November forecast. The 10-year Treasury rate would be 2.2% by that early 2023 period, the same as projected in the November forecast. The Blue Chip panel thus see the earlier Fed actions as perhaps reducing market concerns sufficiently to keep investors comfortable.

Long-term Federal Funds Rate Just Above 2%. This month's survey also includes the semi-annual long-term projections. GDP growth in 2023 is projected at 2.6% and then easing to 2.0% by 2026. This is just 0.1% below the projections for 2028-2032 made at the end of May. Inflation, measured by the personal consumption expenditure price index, would be 2.5% in 2023 and then ease to 2.1% across the rest of the forecast horizon. The 2% long-term growth rate would be associated with a federal funds rate edging up to 2.2% by 2026 and hovering near there after that. The 10-year Treasury yield would be 3.2% by mid-decade.

+ + + + +

SOFR Forecast Preview

Here are the Consensus forecasts for 3-month LIBOR and for the Secured Overnight Financing Rate, i.e., SOFR. As we have explained in the last couple of months, the LIBOR rates will be discontinued starting in January and for representations of short-term private sector borrowing rates, markets will focus on SOFR. Thus, beginning in the January edition of the Blue Chip Financial Forecasts, we will include SOFR in the regular forecast tables and show the forecasts of individual survey participants, not just the consensus average.

We clearly invite questions from forecast participants and subscribers to the publication. Meantime, readers can refer to this link from the New York Federal Reserve Bank, which is the official source of the daily SOFR rates.

	LIBOR 3-Month	**Secured Overnight Financing Rate (SOFR)**
Q1 2021	0.20	0.04
Q2 2021	0.16	0.02
Q3 2021	0.13	0.05
Q4 2021	0.18	0.06
Q1 2022	0.21	0.07
Q2 2022	0.26	0.09
Q3 2022	0.37	0.18
Q4 2022	0.57	0.36
Q1 2023	0.73	0.48

Carol Stone, CBE (Haver Analytics, New York, NY)

Dividend Yields of Six Company Proxy Group

Company	**Atmos Energy Corp**	**Chesapeake Utilities**	**Nisource Inc**	**Northwest Natural Gas Co**	**One Gas Inc.**	**Spire Inc.**
Symbol	*ATO*	*CPK*	*NI*	*NWN*	*OGS*	*SR*
Div	2.92	2.16	0.98	1.94	2.64	2.86
52-wk low	85.80	113.49	23.48	43.07	62.52	59.60
52-wk high	122.11	146.30	32.59	57.63	91.79	77.95
Spot Price	122.05	139.37	32.46	51.72	91.37	74.55
Spot Div Yield	2.39%	1.55%	3.02%	3.75%	2.89%	3.84%
52-wk Div Yield	2.81%	1.66%	3.50%	3.85%	3.42%	4.16%
Average	**2.60%**	**1.61%**	**3.26%**	**3.80%**	**3.16%**	**4.00%**

	Average
Spot Div Yield	**2.91%**
52-wk Div Yield	**3.23%**
Average	**3.07%**

Source:	Barrons	April 7, 2022
	Value Line	February 25, 2022

Five-Year Growth Estimate Forecast for Proxy Group

Company	Symbol	Yahoo	Zacks	Morningstar	Value Line	Average
		Source				
Atmos Energy Corp	ATO	7.20%	7.30%	7.30%	7.50%	7.33%
Chesapeake Utilities	CPK	4.74%	NMF	8.20%	8.00%	6.98%
Nisource Inc	NI	3.52%	7.20%	7.50%	10.50%	7.18%
Northwest Natural Gas Co	NWN	5.70%	5.10%	6.40%	6.00%	5.80%
One Gas Inc.	OGS	2.90%	5.00%	NMF	6.00%	4.63%
Spire Inc.	SR	7.31%	5.30%	7.60%	9.00%	7.30%
Average						**6.54%**

Source:
(From Internet)
April 7, 2022

Expected Market Cost Rate of Equity
Using Data for the Proxy Group of Six Natural Gas Companies
5-Year Forecasted Growth Rates

	Time Period	Adjusted Dividend Yield	Growth Rate	Expected Return on Equity
		(1)	(2)	(3=1+2)
(1)	**52-Week Average** **Ending:** April 7, 2022	3.23%	6.54%	9.77%
(2)	**Spot Price** **Ending:** April 7, 2022	2.91%	6.54%	9.44%
(3)	**Average:**	**3.07%**	**6.54%**	**9.61%**

Sources: Value Line February 25, 2022
Barrons April 7, 2022

Company	Beta
Atmos Energy Corp	0.80
Chesapeake Utilities	0.80
Nisource Inc	0.85
Northwest Natural Gas Co	0.80
One Gas Inc.	0.80
Spire Inc.	0.85
Average beta for CAPM	**0.82**

Source:
Value Line
February 25, 2022

Risk-Free Rate

Treasury note 10-yr Note	**Yield**
3Q 2022	2.60
4Q 2022	2.80
1Q 2023	2.90
2Q 2023	3.00
3Q 2023	3.10
2023-2027	2.90
Average	**2.88**

Source:
Blue Chip
April 1, 2022 and December 1, 2021

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	1.90%		10.67%	(a)	12.57%
S&P 500	1.48%	(b)	14.30%		15.78%
Average Expected Market Return				=	**14.17%**

(a) ((1+50%)^.25) -1) Value Line forecast for the 3 to 5 year index appreciation is 50%
(b) S&P 500 dividend yield multiplied by half the S&P 500 growth rate
(b) 1.38%*((1+14.30%/2)) = 1.48%

Sources:

S&P 500 Growth Rate (Morningstar)	4/7/2022	14.30%
S&P 500 Dividend Yield (Barrons)	4/7/2022	1.38%
Value Line Dividend Yield	4/8/2022	1.90%
Value Line Appreciation Yield	4/8/2022	50%

CAPM with Forecasted Return

Re	Required return on individual equity security
Rf	Risk-free rate
Rm	Required return on the market as a whole
Be	Beta on individual equity security

Re = Rf+Be(Rm-Rf)

Rf =	2.88
Rm =	14.17
Be =	0.82
Re =	**12.14**

Sources: Value Line February 25, 2022
Blue Chip April 1, 2022 and December 1, 2021

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. I & E RR-010-D:

Reference Columbia Statement No. 8, page 44, line 22 through p. 45, line 2:

A. State whether Mr. Moul is aware of any natural gas distribution utilities throughout the United States that have been granted a Commission authorized 11.20% or higher cost of common equity in the past two years.

B. If the response to Part A is yes, state which company/companies have been authorized such cost of common equity and in what jurisdiction.

Response:

A. Mr. Moul has not researched this issue.

B. See the response to (A) above.

I&E Statement No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Revenue Normalization Adjustment
Cost of Service Study
Scale Back of Rates

TABLE OF CONTENTS

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

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

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia Gas" or "Company") requested base rate revenue increase of $82,151,953.[1] My testimony specifically addresses the following issues:

- Fully Projected Future Test Year ("FPFTY") Reporting Requirements;
- Revenue Normalization Adjustment;
- Revenue allocation;
- Rate structure;
- Customer charge;
- Cost of Service allocation; and
- Scale back of rates.

<u>FPFTY REPORTING REQUIREMENTS</u>

Q. WHAT TEST YEAR DID THE COMPANY ELECT TO USE IN THIS PROCEEDING?

A. Columbia elected to base its rates on an FPFTY ending December 31, 2023. The Company also addressed a historic test year ("HTY") ended November 30, 2021 and future test year ("FTY") ending November 30, 2022 (Columbia St. No. 4, p. 3).

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1 Columbia Gas Statement No. 4, p. 4.

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE WILL BE ASSOCIATED WITH COLUMBIA'S INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2023?

A. The Company's claimed rate base for the FPFTY ending December 31, 2023 is $2,958,295,013 (Columbia Ex. No. 108, p. 3, col. 5). Columbia's rate base for the FTY ending November 30, 2021 is $2,609,947,601 (Columbia Ex. No. 108, p. 3, col. 3). Therefore, $348,347,412 ($2,958,295,013 – $2, 609,947,601) of rate base additions are associated with the thirteen months between the end of FTY and the end of the FPFTY.

Q. DID THE COMPANY PROVIDE A SCHEDULE SHOWING PLANT ADDITIONS AND RETIREMENTS THAT SUPPORT THE PROJECTED LEVEL OF TOTAL PLANT IN THE FTY AND FPFTY RATE BASE?

A. Yes. The Company provided Columbia Ex. No. 108, Sch. 1 showing detailed plant additions and retirements for the FTY and FPFTY.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT COLUMBIA PROJECTS TO BE IN SERVICE DURING THE FTY ENDING NOVEMBER 30, 2022 AND THE FPFTY ENDING DECEMBER 31, 2023?

A. Yes. I recommend that the Company provide the Bureau of Investigation and Enforcement and the Office of Consumer Advocate with an update to Columbia

Exhibit No. 108, Schedule 1 no later than April 1, 2023, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2022. An additional update should be provided for actuals through December 31, 2023, no later than April 1, 2024.

Q. WHY DO YOU RECOMMEND THAT COLUMBIA PROVIDE THESE UPDATES?

A. I&E continues to believe that there is value in determining how closely Columbia's projected investments in future facility comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between Columbia's projected and actual results will help inform the Commission and the parties in Columbia's future rate cases as to the validity of Columbia's projections.

Using a FPFTY, Columbia is requesting ratepayers pre-pay a return on its projected investment in future facilities that are not in place and providing service at the time the new rates take effect, but also are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments comport with projections used in setting rates using the FPFTY provides the Commission with actual data to gauge the accuracy of Columbia's projected investments in future proceedings.

REVENUE NORMALIZATION ADJUSTMENT

Q. WHAT IS A REVENUE NORMALIZATION ADJUSTMENT?

A. A revenue normalization adjustment ("RNA") is a tariff provision that is "designed to 'break the link' between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers." (Columbia St. No. 6, p. 29). In other words, the Company is proposing to stabilize its revenue level received from customers by enacting a "benchmark distribution revenue level" and adjusting revenues to that point regardless of actual usage levels.

Q. IS THE COMPANY PROPOSING AN RNA IN THIS PROCEEDING?

A. Yes. The Company is proposing to apply an RNA to its non-CAP residential customers (Columbia St. No. 6, p. 29).

Q. HOW DOES THE COMPANY PROPOSE TO ENACT THE RNA?

A. The Company proposes to set the benchmark distribution revenue levels by month for the peak period, October through March, and off-peak period, April through September, separately, based on the revenue requirement approved in the present proceeding (Columbia St. No. 6, p. 34).

Q. IS THIS THE FIRST PROCEEDING IN WHICH THE COMPANY HAS PROPOSED TO ENACT THE RNA?

A. No. The Company has proposed to enact the RNA in several previous rate cases. Most recently, the Company proposed to enact the RNA in its prior 2021 rate case at Docket No. R-2021-3024296.

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS PROPOSED RNA BETWEEN THE LAST PROCEEDING AND THE PRESENT PROCEEDING?

A. Functionally, no. The Company simply updated its data and proposed rates to align with the FPFTY in the present proceeding.

Q. DO YOU RECOMMEND THAT THE RNA BE APPROVED?

A. No.

Q. WHY DO YOU RECOMMEND THAT THE RNA NOT BE APPROVED?

A. I recommend that the RNA not be approved for the following reasons. First, the Commission recently determined the RNA was unnecessary. Second, the policy statement cited by the Company does not allow Columbia to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides projected lower usage levels.

Q. WHAT DID THE COMMISSION DETERMINE REGARDING THE RNA IN COLUMBIA'S 2020 BASE RATE CASE?

A. The Commission determined that the RNA, as presented in Columbia's 2020 base rate case, was not needed and would not produce rates that are just, reasonable, and in the public interest. (Docket No. R-2020-3018835, pp. 264-265, Order entered February 19, 2021).

Q. DOES THE REFERENCE TO THE STATEMENTS OF POLICY IN THE ALTERNATIVE RATE MAKING DOCKET NEGATE THE OBLIGATION OF A COMPANY TO CHARGE RATES THAT ARE JUST, REASONABLE, AND IN THE PUBLIC INTEREST?

A. No. The Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883 does not negate the obligation of a Company to charge rates that are just and reasonable. Moreover, Columbia seeks to point to the 2015 Policy Statement as justification for the RNA but disregards the Commission's February 19, 2021 Order denying Columbia's RNA proposal.

Q. DOES THE USE OF THE FPFTY ALREADY INCLUDE PROJECTED ADJUSTMENTS FOR DECLINES IN USAGE?

A. Yes. Through Act 11 and the FPFTY, the Company is permitted to build into its revenue requirement an adjustment for revenue lost due to a decline in usage that is projected to occur up to a year after rates go into effect. The Company did so in this proceeding as it is projecting a reduction in customer usage over the FPFTY and included an adjustment to revenues to account for that reduction, as discussed below.

Q. HAS THE COMPANY DEMONSTRATED A NEED FOR REVENUE STABILIZATION?

A. No. The purpose of revenue stabilization is to remove the inherent risk of not recovering the full amount of revenue requirement allowed by the Commission due to changes in usage. Between the frequent base rate cases filed by the Company, staying out no more than two years, the FPFTY, the DSIC, and the WNA, the Company has demonstrated no need for further revenue stabilization measures. Additionally, the Company has not indicated that the RNA will result in fewer base rate increases, thus removing any benefit from the residential customers. Furthermore, as I stated above, the Company did not add any additional information or support that would cause the Commission to reverse its decision that the RNA does not provide rates that are just, reasonable, and in the public interest.

COST OF SERVICE

Q. WHAT IS AN ALLOCATED COST OF SERVICE ("ACOS") STUDY?

A. A utility provides service to a defined set of customer classes that are different in terms of demand and usage patterns. An ACOS allocates or assigns a utility's revenue requirement based on those service differences. In other words, an ACOS is a formalized analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of such a study can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements and, to the extent a particular class is above or below the system average rate of return, show the additional revenues each class receives or conversely the additional revenues that each class contributes to the Company's overall revenues. In addition to the relative provision of revenues, a relative rate of return is also provided, which shows how the rate of return for each class compares to the system average rate of return.

Q. WHAT ARE RATE OF RETURN AND RELATIVE RATE OF RETURN?

A. The rate of return is the Commission authorized return on rate base that is determined in a base rate proceeding. A relative rate of return indicates how the rate of return of each customer class compares to the system average rate of return. In general, a relative rate of return that provides revenue equal to its cost to serve would have a relative rate of return equal to 1.0. If a class of service has a relative rate of return below 1.0, the revenue received from that class does not cover the cost of providing service to that class. If a class of service has a relative rate of return above 1.0, the revenue received from that class exceeds the cost of providing service to that class.

Q. DID THE COMPANY PROVIDE AN ACOS STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three ACOS studies in its filing sponsored by Columbia witness Kevin L. Johnson as he described on page 4 of Columbia Statement No. 6. The first is a customer-demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2), and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. WHAT IS THE LARGEST CAPITAL COST FOR COLUMBIA?

A. On page 10 of Columbia Statement No. 6, Mr. Johnson states that "[m]ains and services account for the majority of the Company's gross plant investment and distribution O&M expenses."

Q. WHAT IS THE MAIN DIFFERENCE BETWEEN THE CUSTOMER-DEMAND AND THE PEAK AND AVERAGE ACOS STUDIES?

A. The difference between the customer-demand ACOS and the peak and average ACOS studies presented by Mr. Johnson in Company Exhibit No. 111 is in the way that each study allocates the costs of mains. Consequently, the two ACOS studies yield different relative rates of return for each rate class.

The customer-demand methodology classifies distribution mains as partially customer related and partially demand related. The customer portion of mains is then allocated to the various customer classes based on the total number of customers, while the demand portion of mains is allocated to classes based on peak day contributions or demand. This methodology was rejected by the Commission in the Company's 2020 base rate case (Docket No. R-2020-3018835, pp. 217-218, Order entered February 19, 2021).

The peak and average ACOS, however, allocates distribution mains to classes based partially on contributions to peak day demand and partially on annual consumption (average demand). This methodology was accepted by the Commission in the Company's 2020 base rate case (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021).

Q. WHICH OF THE THREE ACOS STUDIES SPONSORED BY MR. JOHNSON DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. Consistent with the Commission's Order from Columbia's 2020 base rate case, discussed above, the Company utilized the second ACOS study sponsored by Mr. Johnson, which is the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases (Columbia St. No. 6, p. 4).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED USE OF THE PEAK AND AVERAGE METHODOLOGY TO ALLOCATE THE REVENUE INCREASES AMONG THE DIFFERENT CUSTOMER CLASSES IN THIS PROCEEDING?

A. Yes.

Q. DID THE COMPANY ALSO ELECT TO SHOW THE FLEX RATE CUSTOMERS UNDER THEIR OWN RATE CLASS IN THE COST OF SERVICE STUDY?

A. Yes. This is important so that the Commission can determine the cost to provide service to the flex and non-flex customers and the subsidy being provided by tariff rate customers. With this information, the Commission can establish fair and reasonable rates for all other non-flex customers in non-flex classes.

Q. DOES THE INCLUSION OF FLEX RATE CUSTOMERS NECESSARILY MEAN THAT THE ULTIMATE RELATIVE RATE OF RETURN GOAL IS DIFFERENT THAN 1.0?

A. Yes. Because the inclusion of flex rate customers shifts a portion of the revenue requirement that is unrecovered from the discounted rates to the other customer classes, the ultimate relative rate of return goal is different than 1.0. As shown on I&E Exhibit No. 3, Schedule 1, the actual relative rate of return goal is 1.13 rather than 1.0.

Q. WHAT DO YOU RECOMMEND CONCERNING FUTURE COLUMBIA BASE RATE CASES?

A. I recommend two things in future base rate cases. First, I recommend the Company continue to utilize the peak and average cost of service study to establish rates. Second, I recommend that the Company continue to classify flex rate customers as a separate class in future cost of service studies. The rationale for both of these recommendations is described above.

<u>REVENUE ALLOCATION</u>

Q. IS THE COMPANY'S PROPOSED REVENUE INCREASE ALLOCATION SHOWN ON COLUMBIA EXHIBIT NO. 111, SCHEDULE 2 REASONABLE?

A. No. While the Company's proposed allocation has the effect of moving the relative rates of return for each rate class towards equilibrium, as shown on Columbia Exhibit No. 111, Schedule 2, pages 2-3 and the table below, the final result is that the residential rate class is still providing a significant subsidy to the other rate classes.

Customer Class	Current Rates (Columbia Ex. No. 111, Sch. 2, p. 2)	Proposed Rates (Columbia Ex. No. 111, Sch. 2, p. 1)
RSS/RDS	1.30	1.27
SGS/DS-1	1.09	1.06
SGS/DS-2	1.09	1.05
SDS/LGSS	0.89	0.94
LDS/LGSS	0.27	0.40
MLDS	29.29	22.23
FLEX	(0.69)	(0.52)

Q. WHAT RELATIVE RATES OF RETURN UNDER CURRENT RATES HAS THE COMPANY REPORTED OVER THE COMPANY'S RECENT BASE RATE FILINGS?

A. The following table shows the relative rates of return for Columbia's various rate classes under current rates from the Company's current rate case, 2021 base rate case (Docket No. R-2021-3024296) and 2020 base rate case (R-2020-3018835) using the peak and average cost of service methodology.

Relative Rates of Return under Current Rates			
Customer Class	2022 Rate Case (R-2022-3031211) Columbia Ex. No. 111, Sch. 2, p. 2	2021 Rate Case (R-2021-3024296) Columbia Ex. No. 111, Sch. 2, p. 2	2020 Rate Case (R-2020-3018835) Columbia Ex. No. 111, Sch. 2, p. 2
RSS/RDS	1.30	1.26	1.29
SGS/DS-1	1.09	1.08	1.02
SGS/DS-2	1.09	1.14	1.19
SDS/LGSS	0.88	0.95	0.94
LDS/LGSS	0.27	0.17	0.08
MLDS	29.29	30.41	16.75
FLEX	(0.67)	(0.84)	(0.88)

Q. HAS THE RELATIVE RATES OF RETURN FOR THE VARIOUS RATE CLASSES MADE SIGNIFICANT MOVEMENT TOWARDS SYSTEM AVERAGE RATE OF RETURN?

A. No. As shown in the table above, only the SGS/DS-2, LDS/LGSS, and MLDS classes have made any movement towards the system average rate of return. It is clear, however, that the RSS/RDS and MLDS classes are providing a significant subsidy to the other rate classes. Additionally, from the time of the Company's 2021 base rate case to the current base rate case, the SDS/LGSS rate class has moved farther away from the system average rate of return.

Q. WHAT IS THE DOLLAR AMOUNT OF THE SUBSIDY BEING PROVIDED BY THE RSS/RDS CLASS?

A. The RSS/RDS is providing a subsidy of approximately $19 million to the SGS/DS-1, SGS/DS-2, SDS/LGSS, and LDS/LGSS classes. (I&E Exhibit No. 3, Schedule 1, line 17),

Q. HOW DID YOU DETERMINE THE SUBSIDY?

A. I determined the relative rate of return for each class, excluding the flex rate customers, must be 1.13 to achieve an overall relative rate of return of 1.0. Removing approximately $19 million from the RSS/RSD class lowers the relative rate of return for that class to 1.13 (I&E Ex. No. 3, Sch. 1, lines 17-20).

Q. WHAT DO YOU RECOMMEND REGARDING THE RSS/RDS SUBSIDY?

A. As I discuss further below, in order to remove the subsidy being provided by the RSS/RDS class, I recommend that the first $20 million of any scale back be applied to the RSS/RDS class.

Q. ARE YOU RECOMMENDING A REALLOCATION OF REVENUE FROM THE RSS/RDS CLASS TO THE SDS/LGSS CLASS?

A. Yes. As shown on I&E Exhibit No. 3, Schedule 2, I am recommending a reallocation of $600,000 from the RSS/RDS class to the SDS/LGSS class. This results in a relative rate of return for the SDS/LGSS class, after the $20 million first dollar relief for the RSS/RDS class of approximately 1.03.

Q. WHY ARE YOU RECOMMENDING A $600,000 REALLOCATION OF REVENUE FROM THE RSS/RDS CLASS TO THE SDS/LGSS CLASS?

A. As shown on the table above, the SDS/LGSS class is the only customer class that has had its relative rate of return move further away from the system average relative rate of return following recent base rate cases. This, along with its relative rate of return being below the system average relative rate of return shows that the SDS/LGSS was being subsidized by the RSS/RDS class and that subsidization was not being sufficiently reduced in this base rate case. My recommendation will ensure that this subsidy will be reduced as the SDS/LGSS class moves towards the system average relative rate of return, including the FLEX subsidy, of 1.13 as discussed above.

CUSTOMER COST ANALYSIS

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is a part of a COSS that is used to determine the appropriate fixed customer charges for the various classes and meter sizes. It includes customer costs only.

Q. WHY IS IT NECESSARY TO PERFORM A CUSTOMER COST ANALYSIS?

A. A fixed customer charge represents the revenue that the Company is guaranteed to receive each month, regardless of the level of usage. As acknowledged in the seventh edition of the American Water Works Association M1 Manual, there is a tradeoff between revenue stability from a high customer charge, and affordability and conservation from a low customer charge and higher usage rates.[2]

Q. WHAT IS A DIRECT CUSTOMER COST?

A. A direct customer cost is a cost that changes with the increase or decrease of a single customer.

Q. WHAT IS AN INDIRECT CUSTOMER COST?

A. An indirect customer cost is a customer related cost that does not change with the increase or decrease of a single customer. The Commission has allowed, in past instances, certain indirect customer costs to be included in a customer cost analysis and thus recovered in a customer charge. As an example, in previous cases, the Commission has allowed the indirect cost of Employee Pension and Benefits.

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[2] AWWA Manual of Water Supply Practices M1 Principles of Water Rates, Fees, Charges, Seventh Edition. pp. 154-155.

Q. DID COLUMBIA PREPARE A CUSTOMER COST ANALYSIS TO SUPPORT THE PROPOSED CUSTOMER CHARGE INCREASES IN THIS PROCEEDING?

A. Yes. The Company prepared two customer cost analyses presented in Columbia Exhibit No. 111, Schedule 1, pages 16 and 26. The Company's first customer cost analyses allocates a portion of the cost of mains to customers. The Company's second customer cost analyses does not allocate any portion of the cost of mains to customers. The results of each customer cost analysis are presented in the following table:

Customer Class	Including Mains (Columbia Ex. No. 111, Sch. 2, p. 17, line 43)	Excluding Mains (Columbia Ex. No. 111, Sch. 2, p. 26, line 39)
RSS/RDS	$62.98	$25.47
SGS/DS-1	$73.26	$28.36
SGS/DS-2	$183.16	$52.76
SDS/LGSS	$1,066.31	$267.11
LDS/LGSS	$7,062.09	$1,403.41
MLDS	$648.65	$524.02
FLEX	$22,717.98	$3,136.45

Q. HOW DID COLUMBIA DETERMINE THE FIXED MONTHLY COSTS BY CUSTOMER CLASS ABOVE?

A. According to Columbia witness Johnson, the Company designed its rates to include the principles of efficiency, simplicity, continuity, fairness, and earnings stability (Columbia St. No. 6, p. 16).

Q. DO YOU BELIEVE THAT THE COMPANY'S CUSTOMER COST ANALYSIS THAT INCLUDES THE COST OF MAINS SHOULD BE CONSIDERED?

A. No. The Commission has established in Columbia's 2020 base rate case that mains are not properly included as a customer cost (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021). Therefore, the Company's customer cost analysis that includes the cost of mains should not be utilized in this proceeding.

<u>CUSTOMER CHARGES</u>

Q. WHAT CUSTOMER CHARGES IS THE COMPANY PROPOSING FOR EACH RATE CLASS?

A. The customer charges for each rate class that received a proposed increase is shown in the table below. (Columbia No. 103, Sch. No. 8, pp. 5-9).

Rate Schedule (Therms, annually)	Present Rate	Change	Proposed Rate	Percent Increase
RS, RDS, RCC				
All Usage	$16.75	$8.72	$25.47	52.1%
SGSS1, SCD1, SGDS1				
≤6,440	$29.92	$4.31	$34.23	14.4%
SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$57.00	$8.36	$65.36	14.7%
SDS/LGSS				
>64,400 to ≤110,000	$265.00	$54.30	$319.30	20.5%
>110,000 to ≤540,000	$1,050.11	$215.18	$1,265.29	20.5%
LDS				
>540,000 to ≤1,074,000	$2,673.99	$587.29	$3,261.28	22.0%
>1,074,000 to ≤3,400,000	$4,159.15	$913.47	$5,072.62	22.0%
>3,400,000 to ≤7,500,000	$8,020.79	$1,761.61	$9,782.40	22.0%
>7,500,000	$11,882.42	$2,609.74	$14,492.16	22.0%

Q. ARE YOU RECOMMENDING ADJUSTMENTS TO ANY OF THE COMPANY'S PROPOSED CUSTOMER CHARGES?

A. Yes. Based on the customer cost analysis that does not include the cost of mains, as described above, the customer charges proposed for the SGS1, SGS2, and SDS/LGSS classes are too high. I am not recommending an adjustment to the proposed customer charges for the LDS customers because higher usage customers generally favor a higher fixed charge and lower usage charges.

Furthermore, while I recognize that the Company's proposed residential customer charge is supported by the customer cost analysis, I also recognize that the proposed 52.1% increase described above is excessive.

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED THAT RATE SHOCK AND GRADUALISM DO NOT APPLY TO THE CUSTOMER CHARGE INDIVIDUALLY?

A. Yes. The Commission has stated in UGI Electric at Docket No. R-2017-2640058 (Order entered October 25, 2018, pp. 173-174), that rate shock and gradualism do not apply to the customer charge individually. However, on page 175 of that same case, the Commission determined that in spite of the higher customer cost determination in the cost of service study, the customer charges should be included in the scale back. Additionally, due to the economic factors of increased prices and high inflation currently affecting customers, it is not reasonable to limit customers' ability to affect their bill by allocating so much of the residential revenue increase to the customer charge. Therefore, I recommend that reduction in the RSS/RDS revenue increase by the first dollar relief in the scale back, described below, be applied solely to the residential customer charge and that the customer charge be included in any further scale back of rates. A reduction of approximately $20 million applied solely to the customer charge would result in a reduction to the Company's proposed customer charge of approximately $4.86 ($20,000,000 / 4,116,692) from $25.47 to $20.61.

Q. WHAT CUSTOMER CHARGES ARE YOU RECOMMENDING FOR THE SGS1, SGS2, AND SDS/LGSS CLASSES?

A. I am recommending the customer charges for the SGS1, SGS2, and SDS/LGSS classes be adjusted to be consistent with the customer cost analysis as follows:

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Present Rate	Company Proposed Rate	Change	I&E Proposed Rate
SGSS1, SCD1, SGDS1					
≤6,440	$28.36	$29.92	$34.23	($5.87)	$28.36
SGSS2, SCD2, SGDS2					
>6,440 to ≤64,440	$57.00	$57.00	$65.36	($8.36)	$57.00
SDS/LGSS					
>64,400 to ≤110,000	$267.11	$265.00	$319.30	($52.19)	$267.11
>110,000 to ≤540,000	$1,403.41	$1,050.11	$1,265.29	$0.00	$1,265.29

<u>CUSTOMER CHARGE - MISCELLANEOUS</u>

Q. ARE THERE ANY OTHER ISSUES REGARDING THE CUSTOMER CHARGE THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. In its response to I&E-RS-16-D and I&E-RS-17-D, attached as I&E Exhibit No 3, Schedule 3, the Company stated that it does not prorate the customer charge for customers who either start service or end service prior to the end of the billing cycle. In other words, if a customer discontinues service at the beginning of the billing month, the customer charge on the final bill the customer pays is based upon a full month.

Q. WHAT REASON DID THE COMPANY PROVIDE FOR NOT PRORATING THE CUSTOMER CHARGE FOR CUSTOMERS WHO START OR END SERVICE PRIOR TO THE END OF THE BILLING PERIOD?

A. As shown on I&E Exhibit No. 3, Schedule 3, the Company pointed to the fixed costs for meter reading, billing, installing and replacing pipelines, meters, and account servicing that the customer charge is designed to recover. It further claimed that costs recovered through the monthly customer charge do not vary based on whether the customer receives service for the entire billing period or connects or disconnects service during the billing period and that it would not be appropriate to prorate the customer charge for customers who do not take service from Columbia for the entire billing period.

Q. WHAT DO YOU RECOMMEND REGARDING THE PRORATION OF COLUMBIA'S CUSTOMER CHARGE?

A. I recommend that Columbia begin prorating its customer charge for customers who begin or end service prior to the end of the billing period and adjust its tariff to reflect this practice.

Q. WHY DO YOU RECOMMEND COLUMBIA PRORATE ITS CUSTOMER CHARGE FOR CUSTOMERS WHO START SERVICE OR LEAVE SERVICE PRIOR TO THE END OF THE BILLING PERIOD?

A. This recommendation will rectify the current Company policy of charging customers for service not received. As described above, when a customer leaves prior to the end of the billing period, Columbia collects the full customer charge from that customer even though that customer will no longer be a customer for the entire billing period. Columbia's explanation that the customer charge is designed to recover certain costs in a month whether or not a customer receives service for the entire month is without merit. It is simply not reasonable to charge customers for services that they do not receive.

Q. ARE YOU AWARE OF ANY OTHER PENNSYLVANIA UTILITIES THAT PRORATE CUSTOMER CHARGES FOR CUSTOMERS WHO BEGIN OR END SERVICE PRIOR TO THE END OF THE MONTH?

A. Yes. Both Citizens' Electric Company of Lewisburg (I&E Ex. No. 3, Sch. 4) and PPL Electric Utilities, Inc. (I&E Ex. No. 3, Sch. 5) include a provision in its tariff regarding the proration of customer charges.

SCALE BACK OF RATES

Q. HOW DID THE COMPANY ALLOCATE THE $82,151,953 TOTAL INCREASE TO THE VARIOUS CLASSES?

A. The Company proposed to allocate the rate increase to the various rate classes as follows: RSS/RDS approximately $56.4 million or 9.4%; SGS/DS-1 approximately $6.9 million or 9.4%; SGS/DS-2 approximately $7.3 million or 9.7%; SDS/LGSS approximately $6.2 million or 17.3%; LDS/LGSS approximately $5.3 million or 21.7%; and minimal changes to the MLDS and FLEX classes (I&E Ex. No. 3, Sch. 6, p. 1, lines 15-16).

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend that the first $20,000,000 reduction be applied to the RSS/RSD class customer charge (I&E Ex, No. 3, Sch. 6, p. 2, line 13). Any remaining reduction should be applied on a proportional basis to the percentage increases shown on I&E Ex. No. 3, Sch. 6, p. 2, line 16, except for the SDS/LGSS and LDS/LDSS class.

Q. WHY DO YOU RECOMMEND THE FIRST $20 MILLION OF A SCALE BACK BE APPLIED TO THE RSS/RDS CLASS?

A. As I discussed above, under the Company's proposed revenue allocation, the residential class is providing an approximately $20 million subsidy to the other rate classes. Therefore, it is reasonable to remove that subsidy prior to any further scale back of rates.

Q. WHY DO YOU RECOMMEND THAT THE LDS/LGSS CLASS NOT RECEIVE ANY SCALE BACK?

A. As shown on Columbia Exhibit 111, Schedule 2, p. 2, the LDS/LGSS class has a relative rate of return under proposed rates of 0.4, which is significantly under 1.13. Therefore, this rate class should not receive any scale back of rates in order to move its relative rate of return towards 1.13 (I&E Ex. No. 3, Sch. 2, column H).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present
Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008
Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008
J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007
CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL
- Attended Society of Depreciation Professionals Annual Conference and Training

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. PAWC Clarion Wastewater Operations, Docket No. R-2010-2166208
6. PAWC Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Columbia Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition, Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172
37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934

40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209
44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818
68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208
72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212

74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835
80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829
82. PGW 1307(f), Docket No. R-2021-3023970
83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618
86. Columbia Gas of Pennsylvania, Inc., Docket No. R-2021-3024926
87. Duquesne Light Company, Docket No. R-2021-3024750
88. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2021-3025652
89. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773 et al.
90. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Lower Makefield Township, Docket No. A-2021-3024267
91. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386
92. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the York City Sewer Authority, Docket No. A-2021-3024681
93. City of Lancaster – Bureau of Water, Docket No. R-2021-3026682
94. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of East Whiteland Township, Docket No. A-2021-30246132
95. UGI Utilities, Inc. – Gas Division, Docket No. R-2021-3030218
96. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2022-3030661

I&E Exhibit No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Exhibit to Accompany

the

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Revenue Normalization Adjustment
Cost of Service Study
Scale Back of Rates

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS SHOWING UNITIZED PROPOSED REVENUE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

ALLOCATED COST OF SERVICE — **111, SCHEDULE 2**
PEAK & AVERAGE —
WITNESS: K. L. Johnson

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
			$	$	$	$	$	$	$	$
1	ORIGINAL PROPOSED REVENUE [ORIGINAL FILING]		$896,657,347	$655,435,862	$80,515,598	$83,152,274	$41,830,544	$29,467,615	$1,971,082	$4,284,374
2	**First Dollar Releif**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	TOTAL REVENUE [PAGE 6]		$896,657,348	$655,435,862	$80,515,598	$83,152,274	$41,830,544	$29,467,615	$1,971,082	$4,284,374
4	PRODUCTS PURCHASED [PAGE 7]		$235,166,198	$177,821,427	$25,361,618	$25,621,440	$5,559,491	$279,454	$522,768	$0
5	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		$246,645,581	$176,713,417	$17,017,656	$16,341,371	$10,956,214	$12,952,290	$36,838	$12,627,795
6	DEPRECIATION & AMORTIZATION [PAGE 5]		$116,724,231	$71,651,290	$10,206,441	$10,592,372	$7,089,435	$8,548,775	$31,212	$8,604,707
7	TAXES OTHER THAN INCOME [PAGE 9]		$3,580,973	$2,329,649	$306,616	$288,743	$194,417	$231,941	$247	$229,360
8	TOTAL EXPENSES & TAXES OTHER THAN INCOME		$602,116,983	$428,515,783	$52,892,331	$52,843,926	$23,799,556	$22,012,461	$591,066	$21,461,861
9	OPERATING INCOME BEFORE TAXES		$294,540,365	$226,920,079	$27,623,267	$30,308,348	$18,030,988	$7,455,154	$1,380,016	($17,177,487)
10	INCOME TAXES		$55,731,512	$48,053,298	$5,395,309	$5,953,632	$3,327,844	($125,619)	$392,661	($7,265,612)
11	INVESTMENT TAX CREDIT	12	($221,354)	($132,184)	($19,499)	($21,051)	($14,138)	($17,133)	($47)	($17,303)
12	NET INCOME TAXES		$55,510,158	$47,921,115	$5,375,810	$5,932,581	$3,313,706	($142,752)	$392,614	($7,282,915)
13	OPERATING INCOME		$239,030,207	$178,998,965	$22,247,457	$24,375,767	$14,717,282	$7,597,906	$987,402	($9,894,572)
14	RATE BASE [PAGE 10]		$2,958,295,013	$1,748,524,511	$259,742,831	$287,859,226	$192,761,937	$233,132,653	$549,766	$235,724,089
15	RATE OF RETURN EARNED ON RATE BASE		8.080%	10.237%	8.565%	8.468%	7.635%	3.259%	179.604%	-4.198%
16	UNITIZED RETURN		1.000	1.267	1.060	1.048	0.945	0.403	22.228	(0.520)
17	Subsidy		$937,140	($19,128,860)	$1,500,000	$1,942,000	$2,907,000	$13,717,000	$0	$0
18	Total Operation Revenue		$239,967,347	$159,870,105	$23,747,457	$26,317,767	$17,624,282	$21,314,906	$987,402	($9,894,572)
19	RATE OF RETURN EARNED ON RATE BASE		8.112%	9.143%	9.143%	9.143%	9.143%	9.143%	179.604%	-4.198%
20	**UNITIZED RETURN**		**1.00**	**1.13**	**1.13**	**1.13**	**1.13**	**1.13**	**22.23**	**-0.52**

I&E Exhibit No. 3
Schedule 1

COLUMBIA GAS OF PA INC.
RATE OF RETURN BY CLASS AFTER FIRST DOLLAR RELIEF
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023

ALLOCATED COST OF SERVICE STUDY | **Based Upon:** Exhibit 111 | **Schedule 2**
PEAK AND AVERAGE | **Page 1 of 13**

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MDLS (I)	FLEX (J)
1	ORIGINAL PROPOSED REVENUE [ORIGINAL FILING]		$896,657,348	$655,435,862	$80,515,598	$83,152,274	$41,830,544	$29,467,615	$1,971,082	$4,284,374
2	**Scale Back**		**-$20,000,000**	**-$20,600,000**	**$0**	**$0**	**$600,000**	**$0**	**$0**	**$0**
3	I&E Adjusted TOTAL REVENUE [PAGE 6]		$876,657,348	$634,835,861	$80,515,598	$83,152,274	$42,430,544	$29,467,615	$1,971,082	$4,284,374
4	PRODUCTS PURCHASED [PAGE 7]		$235,166,198	$177,821,427	$25,361,618	$25,621,440	$5,559,491	$279,454	$522,768	$0
5	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		$246,249,581	$176,317,417	$17,017,656	$16,341,371	$10,956,214	$12,952,290	$36,838	$12,627,795
6	DEPRECIATION & AMORTIZATION [PAGE 5]		$116,724,232	$71,651,290	$10,206,441	$10,592,372	$7,089,435	$8,548,775	$31,212	$8,604,707
7	TAXES OTHER THAN INCOME [PAGE 9]		$3,580,973	$2,329,649	$306,616	$288,743	$194,417	$231,941	$247	$229,360
8	TOTAL EXPENSES & TAXES OTHER THAN INCOME		$601,720,984	$428,119,783	$52,892,331	$52,843,926	$23,799,557	$22,012,460	$591,065	$21,461,862
9	OPERATING INCOME BEFORE TAXES		$274,936,364	$206,716,078	$27,623,267	$30,308,348	$18,630,987	$7,455,155	$1,380,017	-$17,177,488
10	INCOME TAXES		$50,025,554	$42,176,162	$5,395,309	$5,953,632	$3,499,022	-$125,619	$392,660	-$7,265,612
11	INVESTMENT TAX CREDITS	12	-$221,354	-$132,183	-$19,499	-$21,051	-$14,138	-$17,133	-$47	-$17,303
12	NET INCOME TAXES		$49,804,200	$42,043,979	$5,375,810	$5,932,581	$3,484,884	-$142,752	$392,613	-$7,282,915
13	OPERATING INCOME		$225,132,164	$164,672,099	$22,247,457	$24,375,767	$15,146,103	$7,597,907	$987,404	-$9,894,573
14	RATE BASE [PAGE 10]		$2,958,295,113	$1,748,524,511	$259,742,931	$287,859,226	$192,761,937	$233,132,653	$549,766	$235,724,089
15	RATE OF RETURN EARNED ON RATE BASE		7.610%	9.418%	8.565%	8.468%	7.857%	3.259%	179.604%	-4.198%
16	UNITIZED RETURN		1.00000	1.23758	1.12549	1.11275	1.03246	0.42825	23.60105	(0.55164)

I&E Exhibit No. 3
Schedule 2

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RS

Question No. I & E RS-016-D:

When a customer requests a discontinuance of service, explain if the Company pro-rates the monthly customer charge. If not, explain why.

Response:

If the customer requests a disconnection of service in the middle of a billing period, the final customer bill will reflect the full monthly customer charge. The customer charge covers Columbia's fixed costs for meter reading, billing, installing and replacing pipelines, meters and account servicing. The fixed costs recovered through the monthly customer charge do not vary based on whether the customer receives service for the entire month or disconnects service during the month. Therefore, it would not be appropriate to pro-rate the monthly customer charge for customers who disconnect service during the month.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RS

Question No. I & E RS-017-D:

When a customer requests a connection or reconnection of service, explain if the Company pro-rates the monthly customer charge. If not, explain why.

Response:

If the customer requests a connection of service in the middle of a billing period, the first customer bill will reflect the full monthly customer charge. The customer charge covers Columbia's fixed costs for meter reading, billing, installing and replacing pipelines, meters and account servicing. The fixed costs recovered through the monthly customer charge do not vary based on whether the customer receives service for the entire month or requests service connection during the month. Therefore, it would not be appropriate to pro-rate the monthly customer charge for customers who request service connection during the month.

RULES AND REGULATIONS (cont'd)

11. CAPACITY OF COMPANY'S SERVICE FACILITIES

The service connections, transformers, meters and appliances have a definite limited capacity and no addition to the equipment or load of Customer connected shall be made without the previous consent of Company. A violation of this Rule makes Customer liable for damages resulting therefrom.

12. BILLS - RATES

(a) Bills will be rendered monthly for service supplied during the preceding billing period. Bills will separately state the charges for regulated services, non-regulated services, and Default Service (if any). (C)
Normal billing is for a period of approximately 30 days. Bills will be computed on the basis of monthly rates, which will be prorated for initial or final bills which are for periods more or less than a month. Bills as rendered are due and payable at the office of the Company during business hours and shall be considered as received by the Customer when left at or mailed to the place where service is received or such other place as shall have been mutually agreed upon.

(b) The Company reads meters monthly unless conditions beyond control make it impossible to gain access. The Company may render an appropriately marked estimated bill when a meter reading is not obtained. Estimated bills shall be paid in accordance with the provisions of this Rule and the applicable rate schedule.

(c) If unusual circumstances occur during a period for which an estimated bill has been issued and are brought to the Company's attention an appropriate adjustment will be made by Company.

(d) If the bill is not paid within twenty days from the due date thereof as stated in the bill, Customer shall be considered delinquent in payment, and Company may, at any time thereafter prior to the payment thereof, after serving proper notice, discontinue service for non-payment of regulated and PLR service charges. Partial payments will be applied to the bill consistent according to the requirements of subsection (g) below. Failure to receive the bill shall not entitle Customer to relief from payment of the gross bill if not paid within twenty days.

(e) In case the bill is for service to the United States of America, or the Commonwealth of Pennsylvania or any of their Departments or Institutions, the net rate period shall be thirty days.

(C) Indicates Change

PPL Electric Utilities Corporation

RULES FOR ELECTRIC SERVICE **(C)**

RULE 9 - BILLING AND PAYMENT FOR SERVICE

A. BILLING PERIOD

(1) Bills for service supplied during the preceding billing period, other than initial and final bills, are rendered monthly. Normal billing is for a period of 26-35 days and is based on meter readings taken by Company at the end of each period. **(C)**

(2) When a billing period is more or less than a month, such as for initial or final bills, the monthly rate is prorated.

B. ESTIMATED BILLS

(1) Company may render an appropriately marked estimated bill when a meter reading is not obtained. Company may read meters for longer than monthly intervals and may under such circumstances render estimated interim bills for normal billing periods.

(2) Estimated bills shall be paid in accordance with the provisions of this rule and the applicable rate schedule. If unusual circumstances occur during a period for which an estimated bill has been issued and are brought to the Company's attention, an appropriate adjustment will be made by Company.

(3) Upon request, the Company will supply any customer with a billing schedule and a card from upon which he may record his meter readings at the end of each normal billing period which otherwise would be estimated. If such card is received by the Company by the date specified on the schedule, except where it is apparent to the Company that the information is erroneous, the bill for such period will be computed from the meter reading shown on the card.

(4) The Company will take reasonable measures to obtain meter readings, however, the Company may prepare an estimated bill for any customer if extreme weather conditions, emergencies, equipment failure, work stoppages, or other circumstances prevent actual meter readings or if Company personnel are unable to gain access to obtain an actual meter reading.

C. DUE DATE

The due date specified on the bill is not less than 15 days from the date bill is mailed except that for service under, or billed in conjunction with, residential rate schedules the due date is not less than 20 days from the date bill is mailed and for service to federal, state or local governments or to any governmental department, institution or authority, the due date is not less than 30 days from the date bill is mailed via the U.S. Postal Service or sent electronically. **(C)**

(C)

(Continued)

Columbia Gas of Pennsylvania
REVENUE SUMMARY
R-2022-3031211
Present Rate Revenue

LINE NO.	Tariff Revenue (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	Sales Customers		$633,776,200	$498,917,528	$56,551,402	$44,093,290	$10,535,087	$23,678,893		
2	Choice Customers		$107,668,516	$55,749,563	$14,709,366	$11,609,638	$25,599,949			
3	Cap Customers		$43,543,597	$43,543,597						
4	Choice Customers		$22,258,132		$2,236,119	$20,022,013	-$507,826	$507,826	$0	
5	MDLS-1		$87,747						$87,747	
6	MDLS-2		$1,319,579						$1,319,579	
7	Negotiated		$4,827,192						$561,302	$4,265,890
8	TOTAL Tariff REVENUE		$813,480,963	$598,210,688	$73,496,887	$75,724,941	$35,627,210	$24,186,719	$1,968,628	$4,265,890
	Other Revenue		**TOTAL**	**RSS/RDS**	**SGS/DS-1**	**SGS/DS-2**	**SDS/LGSS**	**LDS/LGSS**	**MLDS**	**FLEX**
9	Forfeited Discounts		$915,981	$672,302	$83,199	$85,717	$40,331	$27,379	$2,226	$4,827
10	Miscellaneous Revenue		$98,442	$90,139	$7,027	$1,150	$101	$17	$3	$5
11	Other		$10,055	$9,207	$718	$117	$10	$2	$0	$1
12	Total Other		$1,024,478	$771,648	$90,944	$86,984	$40,442	$27,398	$2,229	$4,833
13	First Step Scale Back		$0	$0	$0	$0	$0	$0	$0	$0
14	TOTAL REVENUE		$814,505,441	$598,982,336	$73,587,831	$75,811,925	$35,667,652	$24,214,117	$1,970,857	$4,270,723
15	PROPOSED INCREASE		$82,151,906	$56,453,526	$6,927,767	$7,340,349	$6,162,891	$5,253,498	$224	$13,651
16	PERCENT INCREASE		10.09%	9.42%	9.41%	9.68%	17.28%	21.70%	0.01%	0.32%

Columbia Gas of Pennsylvania
REVENUE SUMMARY
R-2022-3031211
$20.0 Million Scale Back

LINE NO.	Tariff Revenue (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	Sales Customers		$697,766,503	$548,563,133	$61,432,516	$47,393,001	$11,498,257	$28,879,596		
2	Choice Customers		$122,682,650	$62,489,666	$16,441,164	$12,906,184	$30,845,636			
3	Cap Customers		$43,543,597	$43,543,597						
4	Choice Customers		$25,300,040		$2,542,582	$22,757,458	-$557,860	$557,860	$0	
5	MDLS-1		$87,747						$87,747	
6	MDLS-2		$1,319,579						$1,319,579	
7	Negotiated		$4,840,356						$561,302	$4,279,054
8	TOTAL Tariff REVENUE		$895,540,472	$654,596,396	$80,416,262	$83,056,643	$41,786,033	$29,437,456	$1,968,628	$4,279,054
	Other Revenue		**TOTAL**	**RSS/RDS**	**SGS/DS-1**	**SGS/DS-2**	**SDS/LGSS**	**LDS/LGSS**	**MLDS**	**FLEX**
9	Forfeited Discounts		$1,008,378	$740,120	$91,591	$94,364	$44,399	$30,140	$2,450	$5,314
10	Miscellaneous Revenue		$98,442	$90,139	$7,027	$1,150	$101	$17	$3	$5
11	Other		$10,055	$9,207	$718	$117	$10	$2	$0	$1
12	Total Other		$1,116,875	$839,466	$99,336	$95,631	$44,510	$30,159	$2,453	$5,320
13	First Step Scale Back		-$20,000,000	-$20,600,000	$0	$0	$600,000	$0	$0	$0
14	TOTAL SCALED BACK REVENUE		$876,657,348	$634,835,862	$80,515,598	$83,152,274	$42,430,543	$29,467,615	$1,971,081	$4,284,374
15	PRESENT RATE REVENUE		$814,505,441	$598,982,336	$73,587,831	$75,811,925	$35,667,652	$24,214,117	$1,970,857	$4,270,723
16	INCREASE AFTER SCALE BACK		$62,151,907	$35,853,526	$6,927,767	$7,340,349	$6,762,891	$5,253,498	$224	$13,651
17	PERCENT INCREASE		7.1%	6.0%	9.4%	9.7%	19.0%	21.7%	0.0%	0.3%

I&E Statement No. 4
Witness: Tyler Merritt

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Direct Testimony

of

Tyler Merritt

Bureau of Investigation & Enforcement

Concerning:

DISTRIBUTION INTEGRITY MANAGEMENT PLAN
PIPELINE REPLACEMENT
LONG TERM INFRASTRUCTURE IMPROVEMENT PLAN

TABLE OF CONTENTS

INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Tyler Merritt. I am a Fixed Utility Valuation Engineer in the Pipeline Safety Division of the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"). My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. I attended The Pennsylvania State University and earned a Bachelor of Science Degree in Petroleum and Natural Gas Engineering in 2017. I joined the Pennsylvania Public Utility Commission's Safety Division in June 2018.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address Columbia Gas of Pennsylvania, Inc. ("Columbia," "CPA" or "Company") pipeline replacement of bare steel, cast iron, vintage plastic pipe installed before 1982 also known as first-generation plastic pipe, and coated steel installed before 1971. More specifically, the purpose of my direct testimony will address the following issues:

A. Federal and state regulations Columbia is required to follow;

B. Columbia's Distribution Integrity Management Plan ("DIMP");

C. Pipeline replacements of bare steel, cast iron, first-generation plastic, and or coated steel installed before 1971;

D. Columbia's Long Term Infrastructure Improvement Plans ("LTIIP").

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 4 contains schedules relating to my testimony.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS?

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in a rate proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. DID ANY COMPANY WITNESS PROVIDE TESTIMONY ON COLUMBIA'S PIPELINE REPLACEMENT?

A. Yes, Columbia witnesses Kempic[1], Brumley[2], and Anstead[3], each discuss the Company's plans for pipeline replacement.

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1 Columbia Statement No. 1, pp. 11-22.
2 Columbia Statement No. 7, pp. 6-13.
3 Columbia Statement No. 14, pp. 3-13.

DIMP REGULATIONS

Q. WHAT FEDERAL AND STATE REGULATIONS ARE CONTROLLING REGARDING COLUMBIA'S PIPELINE REPLACEMENTS?

A. CPA is mandated to adhere to the DIMP under CFR 49 Part 192.1001-192.1015, Subpart P of the Code of Federal Regulations. Additionally, utilities like Columbia, which are seeking to continue a previously approved Distribution System Improvement Charge ("DSIC") mechanism are required to submit a LTIIP pursuant to 52 Pa Code §121.1 and §121.3.

Q. WHAT ARE THE REQUIREMENTS OF THE DIMP?

A. DIMP requires a natural gas utility to perform the following risk management strategies:

1. Identify the threats to its facilities;
2. Evaluate and rank the risks of threats to the facilities;
3. Identify and implement measures to reduce risk;
4. Measure performance, monitor the results, and evaluate effectiveness;
5. Periodically evaluate and make improvements to the program; and
6. Report the results.

DIMP regulations require Columbia to identify the risks to its pipeline facilities and to create a plan or plans to mitigate and reduce these risks. The Company determines pipeline replacements by risk ranking the different pipeline types and then replacing the pipe based on the highest risk ranking.

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY COMPLY WITH THE DIMP REGULATIONS?

A. Pipeline and Hazardous Materials Safety Administration ("PHMSA") created DIMP regulations to reduce the number of US Department of Transportation ("US DOT") reportable incidents.[4]

LTIIP INTRODUCTION

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY FILE AN LTIIP?

A. A natural gas distribution company must submit an LTIIP for Commission approval to be eligible to recover the reasonable and prudently incurred costs regarding the repair, improvement, and replacement of eligible property via the DSIC. The Company must file an LTIIP, because it provides information on the infrastructure replacements and repairs that are needed. The LTIIP should address the replacement of aging infrastructure and must be sufficient to ensure safe and reliable service.

[4] A PHMSA reportable incident means any of the following events: (1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; (iii) Unintentional estimated gas loss of three million cubic feet or more; (2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident. (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

Q. WHAT ARE THE REQUIREMENTS OF AN LTIIP?

A. The LTIIP must include the following elements:

1. Identification of types and age of eligible property owned and operated by the utility for which it is seeking DSIC recovery;
2. An initial schedule for planned repair and replacement of eligible property;
3. A general description of location of eligible property;
4. A reasonable estimate of quantity of eligible property to be improved or repaired;
5. Projected annual expenditures and means to finance the expenditures;
6. A description of the manner in which infrastructure replacement will be accelerated and how repair, improvement, or replacement will ensure and maintain adequate, efficient, safe, reliable, and reasonable service to customers;
7. A workforce management and training program designed to ensure that the utility will have access to a qualified workforce to perform work in a cost-effective, safe, and reliable manner; and
8. A description of a utility's outreach and coordination activities with other utilities, Department of Transportation, and local governments regarding the planned maintenance/construction projects and roadways that may be impacted by the LTIIP. The LTIIP must address only the specific property eligible for DSIC recovery.[5]

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[5] See 52 Pa Code § 121.3.

RELATIONSHIP BETWEEN DIMP AND LTIIP

Q. WHY DOES I&E REVIEW A COMPANY'S DIMP PLAN DURING RATE CASE PROCEEDINGS?

A. DIMP requirements are part of the Federal Safety Code. Distribution pipeline operators are required to comply with 49 CFR 192 Subpart P-Gas Distribution Pipeline Integrity Management. Included in this subpart are, among other requirements, the requirements to identify threats, evaluate and rank risk, identify and implement measures to address risk and measure performance, monitor results, and evaluate effectiveness. Lastly, the process must include a periodic evaluation and demonstrate improvement in risk reduction. I&E Pipeline Safety Engineers are trained to evaluate compliance with these requirements. If risk scores are not reducing, if risk indicators are flat or increasing, if mitigation measures or replacement numbers are lagging, this raises concerns from a safety standpoint. Assuming a company is adequately addressing the riskiest assets, the risk is expected to reduce over time. If risk is increasing, I&E Pipeline Safety Engineers would pose the following questions:

- Is risk is being calculated in an effective manner?
- Is the company mitigating risk effectively for the proper asset?
- Is the company mitigating the asset aggressively enough to reverse the non-decreasing level of risk?

Q. WHAT IS THE CONNECTION BETWEEN PIPELINE SAFETY'S REVIEW OF DIMP AND LTIIP PROGRAMS?

A. The rate of replacement for risky pipelines, which cast iron and bare steel pipelines are historically either very high, or the highest risk asset in most distribution systems, is monitored, measured, and recorded. This replacement data is reviewed during DIMP inspections and also during rate cases for those companies that claim large capital expenditures for pipeline replacements. Another tool to monitor pipeline replacement is the LTIIP filed for those companies that utilize the DSIC to recover costs for eligible projects. The LTIIP is a forward-looking plan for main replacements that is not particular to specific mains or assets, but as asset groups system wide. For the pipelines, the LTIIP lists the mileage replacement projections per year and usually an overall timeline goal when all of that asset is to be removed from service. The LTIIP is created by the company based on the company's analyses and projections. If, for example, during a rate case, it is determined that system leaks are increasing on a specific asset, the usual conclusion is that the risk is increasing since leaks are a major part of the risk calculation algorithm for most companies. From a safety standpoint, I&E will have elevated concerns when this trend is observed. This then turns attention to that company's LTIIP. If the risk is increasing, or relatively flat, and the company is not meeting the replacement goals established by the company in its LTIIP, I&E Pipeline Safety's concerns are further elevated in that more of this high risk asset is remaining in service and will remain in service for a longer period of time if replacement rates are not changed. Not to mention, the company is not meeting its own replacement goals stated in the LTIIP and filed with the Commission. However, if the LTIIP goals are met, the LTIIP and any related replacement/mitigation plans may need to be more aggressive if the trends indicate increasing risk.

Q. WHAT IS THE RELATIONSHIP BETWEEN LTIIP, DIMP, AND I&E PARTICPATING IN RATE CASES?

A. I&E Pipeline Safety's goal through intervention in base rate cases is to bring to light potential safety impacts that are observed through reported outcomes of the Company's risk calculations, asset replacement and mitigation efforts, replacement costs, LTIIPs, and risk factor indicators, such as incidents and leaks.

COLUMBIA'S RISK OVERVIEW

Q. HOW DOES THE COMPANY EVALUATE RISK?

A. The Company evaluates the top threats to its facilities based on: (1) the DIMP regulations; (2) pipeline safety issues identified by PHMSA; and (3) violations cited by I&E's Pipeline Safety Division. CPA is required to implement pipeline replacements based on its DIMP plan to reduce the risk to the Company's system as required under DIMP regulations. DIMP compliance is not optional; it is a regulation.

Q. WHAT IS THE INDUSTRY'S COMMON MITIGATION MEASURE FOR HIGH RISK PIPELINE SEGMENTS?

A. The industry's common mitigation measure to reduce risk is to replace the highest risk pipelines first. As a company replaces the pipelines determined to be the highest risk, risk should be reduced. The overall risk of the asset group will be reduced as the riskiest pipeline is replaced, provided enough risky pipe is replaced in that asset group to overcome increasing risks presented by remaining segments within that group.

Q. HAVE YOU REVIEWED CPA'S EVALUATION AND RISK RANKING IN ITS DIMP AS IT RELATES TO REPLACEMENT AND BETTERMENT PROJECTS?

A. Yes. Columbia does not apply typical risk scores to each pipe material and instead, uses a software tool, Optimain, to identify individual segments of risky pipe within the system based on the pipe's age and condition.[6] Optimain is comprehensive software being used by all NiSource gas distribution companies to help assess and prioritize the risk associated with priority mains and allocate capital towards those risks.[7] Replacement projects are then scheduled based on the results of this ranking and higher risk segments are prioritized to be replaced. Columbia does, however, apply an overall risk score to its entire system. The

[6] I&E Exhibit No. 4, Schedule No. 1.
[7] Columbia Gas Second LTIIP at Docket No. P-2017-2602917, pp. 12-13 (Order entered September 21, 2017).

overall risk is then decreased each year as long as the risk removed from the system is greater than the increase in risk of the existing pipe segments.

Q. WHAT ARE COLUMBIA'S RISKIEST ASSETS THAT SHOULD BE PRIORITIZED FOR REPLACEMENT?

A. In my opinion, the riskiest assets in a pipeline system have historically been bare steel pipe and cast iron pipe. These materials are seen as the riskiest because they are more susceptible to corrosion leaks over time and now display a higher leak rate per mile than other materials. As shown later in my testimony, the Company's bare steel leak rate is higher than plastic facilities that Columbia proposes to replace in addition to the highest risk pipe material.

Q. HAVE YOU REVIEWED COLUMBIA'S EVALUATION AND RISK RANKING IN ITS DIMP AS IT RELATES TO PIPELINE REPLACEMENT AND BETTERMENT PROJECTS?

A. Yes.

Q. HOW DOES COLUMBIA'S RISK RANKING COMPARE YEAR TO YEAR?

A. Columbia's risk score has decreased from 571,627 in 2017 to 542,933 in 2021. After the creation of a new base line annual risk score in 2017, which resulted in an increase in risk, the Company has reduced risk by an average of 1.28% per year.[8] The lowest year in risk reduction came in 2021, when there was only a 0.26% risk reduction from 2020's risk score despite replacing 9.89 more miles of pipe in 2021.

Q. WHY MIGHT COLUMBIA BE REDUCING LESS RISK ON THE SYSTEM DESPITE REPLACING MORE PIPE?

A. Columbia replaced 10.8 more miles of bare steel in 2021 than in 2020 yet less risk was removed from system.[9] In my opinion, one explanation for this could be that Columbia has not been removing the riskiest segments of bare steel pipe and therefore has not been maximizing risk reduction.

Q. PLEASE DISCUSS COLUMBIA'S AT RISK PIPE REPLACEMENT PROGRESS.

A. The Company's at-risk mains are decreasing each year; however, they are decreasing at a slower rate. The current replacement rates are inadequate to meet its LTIIP goals and reduce system risk. At the end of 2017, Columbia reported 7,548 miles of main with 1,337.8 miles, or 18.1%, being at-risk mains.[10] At the end of 2021, Columbia reported 7,715.5 miles of main with 1,044.1 miles, or 13.5%, being at-risk mains.[11]

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[8] I&E Exhibit No. 4, Schedule No. 2.
[9] I&E Exhibit No. 4, Schedule No. 3, p. 2.
[10] I&E Exhibit No. 4, Schedule No. 4, p. 2.
[11] I&E Exhibit No. 4, Schedule No. 4, p. 2.

Columbia's responses to discovery show that, over the five-year period of 2017-2021, a total of 293.7 miles, or 4.3%, of the at-risk mains were replaced.[12] At this average replacement rate of 0.86% per year, it will take Columbia 15 more years to replace its bare steel, cast iron, and wrought iron mains.

COLUMBIA'S PIPE REPLACEMENT PROGRESS

Q. PLEASE DISCUSS COLUMBIA'S BARE STEEL REPLACEMENT PROGRESS.

A. Columbia reported 1,350.1 miles of bare steel at the beginning of 2017 and 997.4 miles of bare steel at the end of 2021.[13] Columbia replaced a total of 352.7 miles of bare steel over those five years with an average of 70.54 miles per year. At this rate, Columbia will replace all remaining bare steel mains in 14 years. Using this projection, Columbia will not have all bare steel mains replaced until 2035, which is six years after the replacement goal stated in its 2012 and 2017 LTIIPs.

Q. PLEASE DISCUSS COLUMBIA'S CAST IRON MAIN REPLACEMENT PROGRESS.

A. Columbia reported 107.5 miles of cast iron main at the beginning of 2017 and 46.7 miles of cast iron at the end of 2021.[14] In those five years, Columbia replaced

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[12] I&E Exhibit No. 4, Schedule No. 3, p. 2.
[13] I&E Exhibit No. 4, Schedule No. 4, p. 2.
[14] I&E Exhibit No. 4, Schedule No. 4, p. 2.

60.8 miles of cast iron main. Columbia is on pace to replace all cast iron within four years and meet its cast iron replacement goals.

Q. PLEASE DISCUSS COLUMBIA'S FIRST-GENERATION PLASTIC REPLACEMENT PROGRESS.

A. Columbia defines first-generation plastic pipe as pipe that was installed prior to 1982. The Company reported 633.5 miles of pre-1982 plastic pipe and plastic pipe with an unknown install date at the end of 2021.[15] The Company has replaced 11.2 miles in 2021, 10.2 miles in 2020, 9.4 miles in 2019, 6 miles in 2018, and 13.5 miles in 2017.[16] With an average replacement rate of ten miles per year, it would take 63 years to remove all pre-1982 plastic pipe in the system. While the removal of pre-1982 plastic pipe is beneficial for the safety and risk reduction of the system, in my opinion, focusing too many resources in this area will prevent the Company from replacing higher risk pipe that was determined by Columbia's DIMP and meeting its goal set in the LTIIP. The goal of DIMP is to replace the pipe that is the highest risk.

Q. HOW DOES COLUMBIA'S LTIIP ADDRESS PIPELINE REPLACEMENT?

A. Columbia filed its LTIIP with the Commission in 2017 at Docket No. P-2017-

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15 I&E Exhibit No. 4, Schedule No. 4, p. 3.
16 I&E Exhibit No. 4, Schedule No. 3, p. 2.

2602917. Columbia averred in the LTIIP filing that it experienced an increasing number of leaks in areas with a high concentration of aging pipe.[17] Columbia stated in the LTIIP that removal of bare steel and cast-iron pipe will reduce the Company's leakage based on corrosion.[18]

Q. WHAT IS THE COMPANY'S STATED TIME FRAME IN THE LTIIP FOR CAST IRON AND BARE STEEL PIPELINE REPLACEMENT?

A. Columbia's 2017 LTIIP claims that it will replace all cast iron and bare steel pipe in its system by 2029.[19]

Q. WHY DID COLUMBIA CHOOSE THE 2029 REPLACEMENT GOAL AS STATED IN THE LTIIP?

A. In 2007, Columbia was issued a non-compliance letter titled NC-30-07,[20] which is issued whenever I&E finds that an operator has violated federal or state codes. As part of the Company's response to rectify issues identified in NC-30-07, Columbia told the Safety Division that it would eliminate all bare steel and cast iron in the

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[17] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan at Docket No. P-2017-2602917, p. 6.

[18] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan at Docket No. P-2017-2602917, p. 6.

[19] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan at Docket No. P-2017-2602917, p. 10.

[20] I&E Exhibit No. 7, Schedule 3 at Docket No. R-2012-2321748.

system.[21] The replacement schedule was created due to violations found with the Company's corrosion control program and as a direct result of an active corrosion investigation. Columbia also stated in the second LTIIP that "Columbia began repairing or replacing its distribution infrastructure on an accelerated basis in 2007 after identifying an increasing number of leaks in areas with a high concentration of aging pipe." [22] Corrosion on bare steel and cast iron pipe was a known risk in 2007 and fueled the implementation of an accelerated replacement program.

Q. HAS COLUMBIA IDENTIFIED CAST IRON AND BARE STEEL PIPE AS THE PRIORITY FOR REPLACEMENT IN THE PAST?

A. Yes. In the first LTIIP filed in 2012, the Company states, "Columbia anticipates that the replacement of cast iron and bare steel will be completed in approximately seventeen years, or by the end of 2029."[23] In the corresponding footnote, Columbia then states, "After that, Columbia plans to focus on replacing other first generation distribution system components such as Aldyl-A, ineffectively coated steel pipe, distribution regulator stations, etc." [24]

In the second LTIIP filed in 2017, Columbia states that "Columbia's primary focus in its accelerated main replacement program … is replacing its "first

[21] I&E Exhibit No. 7, Schedule 4 at Docket No. R-2012-2321748.

[22] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan at Docket No. P-2017-2602917, p. 6.

[23] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of its Long Term Infrastructure Improvement Plan at Docket No. P-2012-2338282, p. 6.

[24] Columbia Gas of Pennsylvania, Inc. Long Term Infrastructure Improvement Plan (2013-2017), Docket No. P-2012-2338282, p. 8.

generation" bare steel and cast iron pipe which are most susceptible to failure from corrosion, cracks, and leakage." [25] This shows that corrosion on bare steel and cast iron has historically been viewed as the priority for replacement over other pipe materials.

Q. WILL COLUMBIA MEET THE REPLACEMENT GOALS IN ITS LTIIP PLAN?

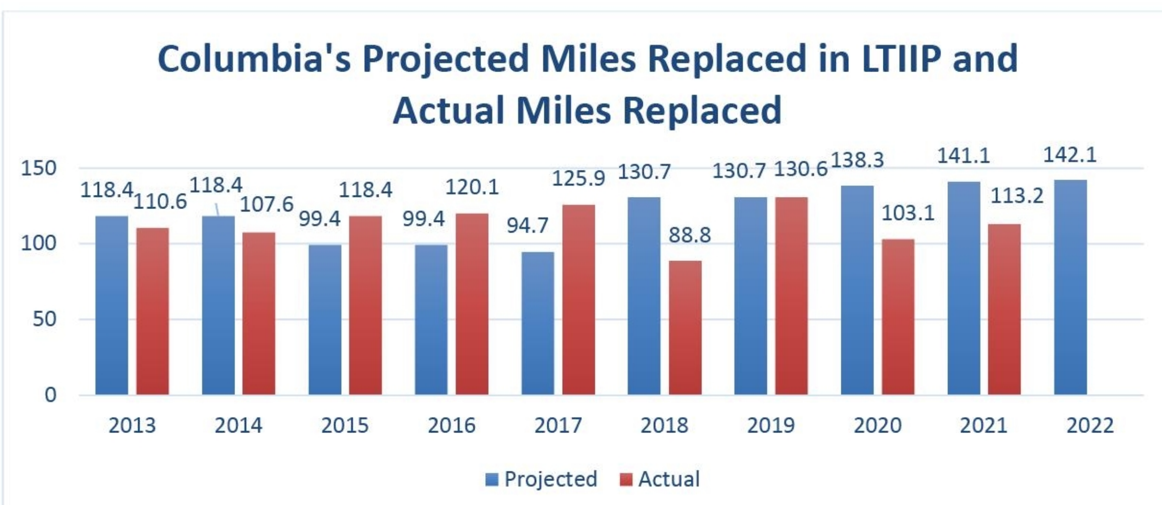
A. No, not at the current rate. I am growing increasingly concerned that Columbia will not meet the target of replacing all cast iron and bare steel mains by 2029 due largely in part to current and past replacement levels.

As part of its LTIIP filing in 2017, Columbia provided a portion of Wesley Soyster's testimony from the 2016 Columbia base rate case in which Mr. Soyster identified cast iron and bare steel as the highest priority for removal according to the Company's DIMP.[26] After converting the replacement schedule from feet to miles per year, Columbia planned to replace 130.7 miles of main in 2018, 130.7 miles of main in 2019, 138.3 miles of main in 2020, 141.1 miles of main in 2021, and 142.1 miles of main in 2022.[27] Columbia has only met this replacement goal in 2019 and has been replacing at an average of 26.2 miles per year below the replacement target from 2018-2021.[28] Although Columbia has removed almost all

[25] Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan at Docket No. P-2017-2602917, p. 11.
[26] Columbia Gas Second LTIIP at Docket No. P-2017-2602917, p. 7 (Order entered September 21, 2017).
[27] Columbia Gas Second LTIIP at Docket No. P-2017-2602917, p. 13 (Order entered September 21, 2017).
[28] I&E Exhibit No. 4, Schedule No. 5.

cast iron from the system, if Columbia's yearly bare steel replacement average from 2017-2021 continues, it will take an additional 14 years for Columbia to remove all bare steel from the system.

The graph and table below demonstrate the mileage of main that Columbia committed to replacing each year compared to the actual mileage that Columbia replaced. As you can see, the mileage that Columbia committed to replacing has increased each year during the second LTIIP. Each year that Columbia does not meet the replacement goal means that Columbia will have to exceed the replacement goal in the following year to remain on pace to replace all cast iron and bare steel by 2029. As Columbia fails to meet their yearly targets, the additional pipe that needs to be replaced each year compounds. Additionally, if first-generation plastic pipe and pre-1971 coated steel is added to the priority pipe category and prioritized for replacement over replacing additional bare steel and cast iron, it will be even more difficult to meet the 2029 replacement goal.



Q. HOW MANY MILES OF PIPE WILL COLUMBIA HAVE TO REPLACE EACH YEAR TO MEET THE 2029 GOAL?

A. For Columbia to meet its 2029 target of having all cast iron and bare steel removed from the system, they must replace 130.5 miles of bare steel and cast iron main every year. This is 48.8 miles more than the yearly average over the last five years.[29] Due to increasing safety concerns, I believe that Columbia should drastically increase its pipeline replacement efforts to ensure that it meets the goal that was originally set in the 2012 and 2017 LTIIPs.

Q. HAS I&E PREVIOUSLY BEEN CONCERNED WITH COLUMBIA MEETING ITS REPLACEMENT GOAL ESTABLISHED IN THE 2012 AND 2017 LTIIP'S?

A. Yes. As previously mentioned, Columbia has previously filed two LTIIPs, the first was filed in 2012 (Docket No. P-2012-2338282) and the second was filed in 2017 (Docket No. P-2017-2602917). Since the first LTIIP in 2012, I&E has raised concerns several times over Columbia's replacement rate of risky pipes and completing the replacement goal of removing all cast iron and bare steel from the system by 2029. These concerns were raised by I&E witnesses in Columbia's previous base rate cases at Docket Nos. R-2014-2406274, R-2015-2501500, R-2016-2521993, R-2016-2529660, and R-2020-3018835. In each of these cases,

[29] I&E Exhibit No. 4, Schedule No. 3.

I&E has expressed concern over Columbia's pipeline replacement goals, yet Columbia still has not increased replacement efforts to meet the original goal that was set in the LTIIP.

LEAK RATES

Q. HAS COLUMBIA'S LEAK RATE BEEN DECREASING WITH ITS BARE STEEL PIPELINE REPLACEMENT PROGRAM?

A. No, the Company's leak rate has not significantly declined in recent years. Columbia's total leaks on bare steel main have stayed relatively the same between 2017 and 2020 but decreased by approximately 17% from 2020 to 2021. More specifically, from 2017 to 2021, Columbia reported a yearly average of .98 leaks per mile of bare steel main when excluding excavation damage leaks. During the same period, Columbia reported a yearly average of 1,186 total leaks on bare steel main. An average of 77.4% of the Company's leaks have been corrosion leaks which occur on metallic pipe materials and are more common on bare steel and cast iron compared to coated steel.[30] Columbia witness Brumley states that 51% of the hazardous or potentially hazardous leaks on Columbia's mains in 2021 were caused by corrosion.[31] Despite Columbia's total leak number decreasing on bare steel, the leak rate per mile of bare steel pipe has not seen the same decrease and was reported at .94 leaks per mile in 2021. It has stayed relatively steady since 2017 and continues to exhibit a much higher leak rate than plastic or coated steel.

[30] I&E Exhibit No. 4, Schedule No. 6, p. 2.
[31] Columbia Statement No. 7, pp. 8, line no. 22 & 23.

Q. WHY IS THE BARE STEEL LEAK RATE STAYING RELATIVELY CONSTANT?

A. Over the last five years, the leak rate per mile of bare steel main has stayed relatively constant and there has not been a significant decrease. In my opinion, one explanation for this is that Columbia may not have been replacing the sections of main with the highest leak rates.

Q. WHAT IS COLUMBIA'S LEAK RATE ON PLASTIC AND PLASTIC INSERT PIPELINES?

A. From 2017 to 2022, Columbia reported a yearly average of 0.04 leaks per mile of plastic or plastic insert main when excluding excavation damage leaks. During the same period, Columbia reported a yearly average of 172 total leaks on their plastic system when excluding excavation damage leaks.[32] There were 26 total hazardous leaks on plastic in the last five years due to plastic pipe cracking.[33]

Q. IS COLUMBIA ABLE TO DETERMINE AN ACCURATE LEAK RATE ON FIRST GENERATION PLASTIC PIPE?

A. No. Columbia does not segregate pre-1981 plastic or 1982 plastic in its total leak data.[34] Columbia does not consider pipe installed in 1982 to be first generation. Unlike bare steel, Columbia is unable to determine a leak per mile rate of pre-1982

32 I&E Exhibit No. 4, Schedule No. 6, p. 2.
33 I&E Exhibit No. 4, Schedule No. 7, p. 2.
34 I&E Exhibit No. 4, Schedule No. 8, p. 3.

plastic. The absence of leak data makes it difficult to obtain an accurate leak rate per mile of first generation plastic main.

RECOMMENDATIONS

Q. WHAT IS YOUR OPINION REGARDING COLUMBIA'S PIPELINE REPLACEMENT?

A. Columbia needs to increase its pipeline replacement effort based on its DIMP to reduce the risks to the Company's systems, as required under DIMP regulations (CFR 49 Part 192.1001-192.1015 Subpart P). Columbia's DIMP has shown that bare steel and cast iron are among the riskiest pipe materials and should be a priority for replacement. Although Columbia has established yearly replacement targets to ensure that it stay on track to meet the goal of having all cast iron and bare steel pipe out of the system by 2029, it has failed to meet those targets in six of the last ten years. Columbia has also failed to meet its goals in the years with the highest replacement targets and has met its goals in three of the lowest yearly targets. This is especially concerning due to the large amount of pipe that needs to be replaced each year for the next 8 years for Columbia to reach its 2029 goal. Columbia is currently 52.8 miles behind its original replacement schedule and faces the challenge of replacing this mileage along with meeting its yearly targets for the next eight years. Therefore, I recommend that Columbia continue to focus on increasing its yearly replacement rate to ensure that it meets its original commitment set in the LTIIP.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. Columbia currently defines first-generation plastic as plastic that was installed before 1982. However, Columbia had an incident on plastic pipe that was installed in 1982. Therefore, I recommend that Columbia include 1982 plastic pipe in the definition of first-generation plastic pipe due to the incident that occurred on pipe that was installed in 1982.

I also recommend that the installation year of plastic pipe should be tracked when a leak is discovered. This will allow Columbia to determine an accurate leak rate on first generation plastic and identify which years or generations of plastic have a higher risk of failing. My recommendation to track the installation year of plastic pipe will aid in more accurate risk ranking and identification of materials that are the riskiest.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

I&E Exhibit No. 4
Witness: Tyler Merritt

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2022-3031211

Exhibit to Accompany

The

Direct Testimony

of

Tyler Merritt

Bureau of Investigation & Enforcement

Concerning:

DISTRIBUTION INTEGRITY MANAGEMENT PLAN
PIPELINE REPLACEMENT
LONG TERM INFRASTRUCTURE IMPROVEMENT PLAN

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-007-D:

Provide the total system risk reduction for the last five calendar years for the following pipe material categories:

A. Cast Iron;

B. Wrought Iron;

C. Bare Steel;

D. Pre 1971 Coated Steel;

E. Pre 1981 Plastic; and

F. 1982 Plastic.

Response:

The replacement of bare steel, cast iron, and wrought main is one of the leading programs to address risk in the DIMP. Because the DIMP risk model is quantitative and validated by Subject Matter Experts (SME), the risk scores for bare steel, cast iron, and wrought iron main are continuously determined to be a high risk by the SME's in order to maintain focus on its replacement. There are several key indicators of risk reduction used by the Company. Those indicators include good, measurable progress on LTIIP, the removal of bare steel, cast iron, and wrought iron pipe (more than 408 miles removed from 2017-2021) and the overall reduction in the number of open type-2 leaks.

To assess the replacement of bare steel, cast iron, and wrought iron pipe as part of the DIMP plan, the Company uses the Optimain risk model to prioritize the replacement of mainline pipe due to age and condition. Historic Optimain risk scores by capital project are not readily available, as the Company uses Optimain to build necessary replacement projects, not to track scores of completed capital projects. However, the Company does maintain historic Optimain risk scores by total pipe segment by year.

Accordingly, the Optimain risk scores by year, identifying the total risk removed with respect to each year, with the associated footage of main replaced for each year, are shown in Table 1 of the response to I&E-PS-06-D.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-006-D:

Provide the total risk score on the distribution system at the end of each of the last five calendar years.

Corrected Response 5/10/2022:

Please see Table 1:

Table 1

Year	Priority Pipe Main Replaced by Foot	Optimain-Total Risk Scores by Year	Risk Removed (from prior year's score)	% Reduction from Prior Year's Score
2021	440,036	542,933	-1,392	0.26%
2020	387,821	544,325	-3,532	0.64%
2019	516,689	547,857	-20,497	3.61%
2018	302,606	568,354	-3,273	0.60%
2017	509,428	571,627	8923	-1.59%*

*The increase in risk score for 2017 can be attributed to improvements made to the Optimain scoring model related to the leak placement process. As a result of this process, the Optimain risk score was adjusted this year from its original status, thus showing a new base line annual risk score for that year.

Original Response:

Please see Table 1:

Table 1

Year	Priority Pipe Main Replaced by Foot	Optimain-Total Risk Scores by Year	Risk Removed (from prior year's score)	% Reduction from Prior Year's Score
2021	440,036	528,718	-1,392	0.26%
2020	387,821	544,325	-3,532	0.64%
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2017	509,428	571,627	8923	-1.59%*

*The increase in risk score for 2017 can be attributed to improvements made to the Optimain scoring model related to the leak placement process. As a result of this process, the Optimain risk score was adjusted this year from its original status, thus showing a new base line annual risk score for that year.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-001-D:

For the last ten calendar years, provide the miles or footages of pipe replaced for the following pipe material categories:

A. Cast Iron;

B. Wrought Iron;

C. Bare Steel;

D. Pre 1971 Coated Steel;

E. Pre 1981 Plastic; and

F. 1982 Plastic.

Response:

Please see Table 1 below for the footages and miles of pipe replaced respectively. The Company does not keep track of Pre-1981 Plastic and 1982 Plastic (E&F), but instead keeps track of Pre-1982 Plastic and Post 1981 Plastic.

Table 1

Pipe Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cast Iron	21,821	28,114	15,787	16,933	30,641	24,318	32,078	25,749	22,586	15,549
Wrought Iron	25,299	30,502	13,190	4,602	0	13993	4291	0	0	1,930
Bare Steel	356,238	392,147	384,269	469,471	448,149	471,117	265,921	490,940	365,235	422,557
Pre 71 Coated Steel	85,785	91,100	111,531	82,873	102,159	83,898	134,760	123,020	102,316	98,379
Pre 82 Plastic	36,871	41,891	43,296	51,070	53,028	71,238	31,643	49,818	54,103	59,210
Total	526,014	583,754	568,073	624,949	633,977	664,564	468,693	689,527	544,240	597,625

Pipe Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cast Iron	4.1	5.3	3.0	3.2	5.8	4.6	6.1	4.9	4.3	2.9
Wrought Iron	4.8	5.8	2.5	0.9	0.0	2.7	0.8	0.0	0.0	0.4
Bare Steel	67.5	74.3	72.8	88.9	84.9	89.2	50.4	93.0	69.2	80.0
Pre 71 Coated Steel	16.2	17.3	21.1	15.7	19.3	15.9	25.5	23.3	19.4	18.6
Pre 82 Plastic	7.0	7.9	8.2	9.7	10.0	13.5	6.0	9.4	10.2	11.2
Total	99.6	110.6	107.6	118.4	120.1	125.9	88.8	130.6	103.1	113.2

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-024:

Reference Columbia's response to I&E-PS-03. Provide the miles or footages of pipe remaining in Columbia's system for the following pipe material categories at the end of the last 10 calendar years:

A. Cast Iron

B. Wrought Iron

C. Bare Steel

D. Pre 1971 Coated Steel

E. Post 1970 Coated Steel

F. Pre 1982 Plastic

G. Post 1981 Plastic

Response:

Please see I&E-PS-024 Attachment A.

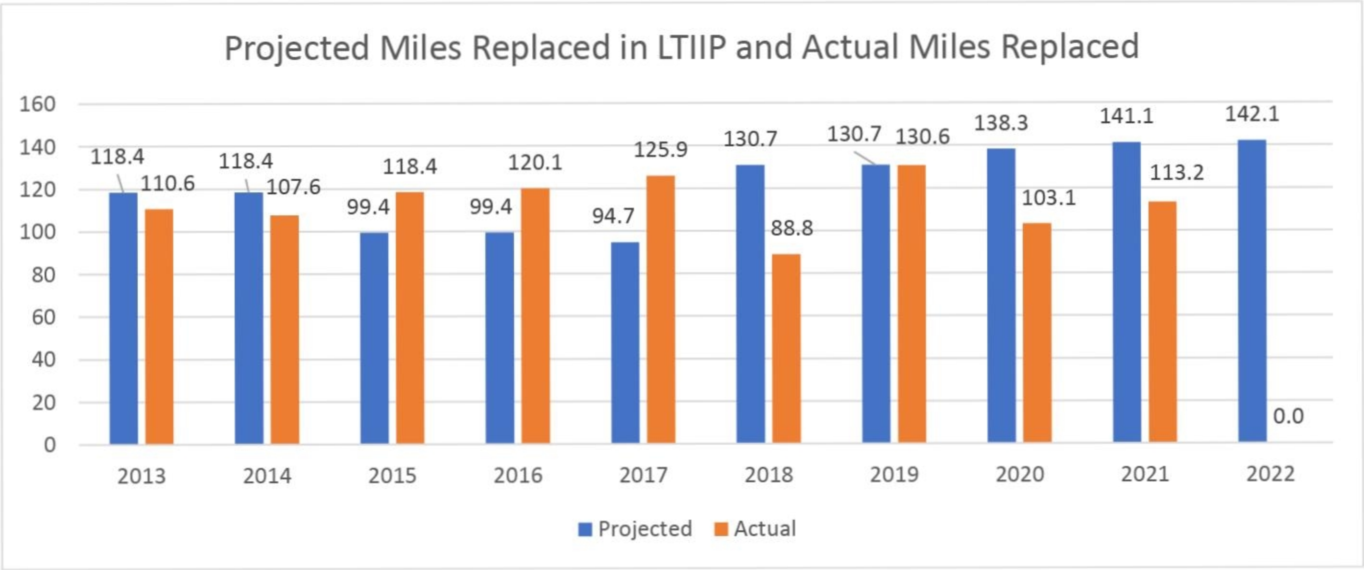
I&E-PS-024 Attachment A

Miles of Priority Pipe Remaining per CPA DOT Distribution Reports

End of Year	Unprotected Bare Steel	Cathodically Protected Bare Steel	Cathodically Protected Coated Steel	Plastic	Cast Iron / Wrought Iron	Other	Total
2012	1641.4	32.2	1745.1	3762.1	147.3	43.7	7371.8
2013	1570.6	26.8	1735.1	3898.3	138.3	41.8	7410.9
2014	1503.9	25.3	1717.7	4028.6	128	39.6	7443.1
2015	1415	22.5	1708.8	4159	117.7	37.4	7460.4
2016	1327.3	22.8	1704.4	4303.9	107.5	34.6	7500.5
2017	1248.2	23.5	1688	4464.3	92.5	31.9	7548.4
2018	1203.4	21.2	1684.8	4601.7	81.5	29.6	7622.2
2019	1112	21.1	1664	4762	69.2	28.1	7656.4
2020	1045.6	22.5	1645.1	4898.1	58.3	26.8	7696.4
2021	974.9	22.5	1624	5022.4	46.7	25	7715.5

Miles of Coated Steel and Plastic broken down - per Columbia's GIS

End of Year	Pre-1971 Coated Steel & Unknown Install Year Coated Steel	Post-1970 Coated Steel	Pre-1982 Plastic & Unknown Install Year Plastic	Post-1981 Plastic
2012	1431.6	313.5	723.5	3038.6
2013	1413	322.1	712.3	3186
2014	1389.6	328.1	704.5	3324.1
2015	1376.1	332.7	694.9	3464.1
2016	1363.4	341	684.5	3619.4
2017	1347.1	340.9	672.2	3792.1
2018	1320.2	364.6	665	3936.7
2019	1300.5	363.5	655.8	4106.2
2020	1282.4	362.7	645.3	4252.8
2021	1264.8	359.2	633.5	4388.9


Projected Miles Replaced in LTIIP and Actual Miles Replaced
160
140
120
100
80
60
40
20
0
118.4
110.6
118.4
107.6
99.4
118.4
99.4
120.1
94.7
125.9
130.7
88.8
130.7
130.6
138.3
103.1
141.1
113.2
142.1
0.0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Projected
Actual

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-021:

Reference Columbia's response to I&E-PS-09. Provide the total number of "Grade 1", "Grade 2+", "Grade 2", and "Grade 3" leaks, excluding leaks caused by excavation damage, found on mains, of each of the following pipe materials for the last five calendar years:

A. Cast Iron
B. Wrought Iron
C. Bare Steel
D. Pre 1971 Coated Steel
E. Pre 1981 Plastic
F. 1982 Plastic

Response:

Please see table 1 below. Note that the companies leak reporting does not segregate based on age of material, therefore plastic, plastic insert and coated steel encompass all leaks on those materials regardless of age.

Table 1

Count of Leaks		2017	2018	2019	2020	2021	Total
1	CAST IRON	7	9	8	8		**32**
	WROUGHT IRON	2	1		2	1	**6**
	STEEL	110	171	132	122	129	**664**
	STEEL TREATED	2	13	14	19	10	**58**
	PLASTIC	31	34	39	47	48	**199**
	PLASTIC INSERT	3	1	1	1	1	**7**
	Total	**155**	**229**	**194**	**199**	**189**	**966**
2+	CAST IRON	7	12	11	2	1	**33**
	WROUGHT IRON	2	2	5	1	3	**13**
	STEEL	212	185	201	151	150	**899**
	STEEL TREATED	20	22	22	15	14	**93**
	PLASTIC	32	38	39	38	21	**168**
	PLASTIC INSERT	2		1			**3**
	Total	**275**	**259**	**279**	**207**	**189**	**1,209**
2	CAST IRON	16	30	29	11	1	**87**
	WROUGHT IRON	20	16	36	8	19	**99**
	STEEL	892	755	925	899	714	**4,185**
	STEEL TREATED	66	85	79	67	60	**357**
	PLASTIC	96	99	96	81	83	**455**
	PLASTIC INSERT	3	2	2	1	8	**16**
	Total	**1,093**	**987**	**1,167**	**1,067**	**885**	**5,199**
3	CAST IRON	1	1	7	2		**11**
	WROUGHT IRON	1	1	1			**3**
	STEEL	44	42	54	32	10	**182**
	STEEL TREATED	3	4	5	1		**13**
	PLASTIC	2	5	2	3	3	**15**
	PLASTIC INSERT						
	Total	**51**	**53**	**69**	**38**	**13**	**224**
Total	**CAST IRON**	**31**	**52**	**55**	**23**	**2**	**163**
	WROUGHT IRON	**25**	**20**	**42**	**11**	**23**	**121**
	STEEL	**1,258**	**1,153**	**1,312**	**1,204**	**1,003**	**5,930**
	STEEL TREATED	**91**	**124**	**120**	**102**	**84**	**521**
	PLASTIC	**161**	**176**	**176**	**169**	**155**	**837**
	PLASTIC INSERT	**8**	**3**	**4**	**2**	**9**	**26**
	Total	**1,574**	**1,528**	**1,709**	**1,511**	**1,276**	**7,598**

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-015-D:

Provide the number of plastic pipe cracks or plastic fusion failures which have resulted in a "Grade 1" (Hazardous) Leak in the last five calendar years and the installation date of the material that failed.

Response:

Please see Table 1 in I&E-PS-15-D Attachment A, for the number of plastic pipe cracks and the year of its installation date of the material that failed, which have resulted in a Grade 1 Leak in the last five calendar years.

Please see Table 2 in I&E-PS-15-D Attachment A, for the number of plastic fusion failures and the year of its installation date of the material that failed, which have resulted in a Grade 1 Leak in the last five calendar years.

I&E-PS-15-D Attachment A

Table 1

Plastic Pipe Cracks

Leak Grade **1**

Year of Installation	1969	1970	1971	1989	1991	1997	2015	2018	Unknown	Grand Total
PLASTIC/PLASTIC INSERT										
MAIN	2	5	5		1				3	16
MNSERV (main/service)						1	1		1	3
SERV (service)		2	1	1				1	2	7
Grand Total	2	7	6	1	1	1	1	1	6	26

Table 2

Plastic Fusion Failures

Leak Grade **1**

Year of Installation	1970	1971	1974	1979	1980	1981	1982	1988	1989	1992	1993
COUPLING - BUTT FUSION											
SERV											
COUPLING - ELECTROFUSION											
MAIN											
SERV											
COUPLING - SOCKET FUSION											
MNSERV		1									
SERV											
OTHER - BUTT FUSION											
MNSERV				1							
PLASTIC/PLASTIC INSERT (Pipe/Pipe BF)											
MAIN	1		1	2	3	1	1				
MNSERV											
SERV					1				1		

SERVICE SADDLE TEE - ELECTROFUSION											
MAIN											
MNSERV											
SERVICE SADDLE TEE - SADDLE FUSION											
MNSERV					1			1		1	1
Grand Total	1	1	1	3	5	1	1	1	1	1	1

2005	2007	2011	2015	2017	2018	2019	2020	2021	Unknown	Grand Total
							1			1
	1		1		1					3
		1								1
1									2	4
									1	1
										1
									4	13
									1	1
									2	4

						1				1
				2	2		1	1	1	7
									1	5
1	1	1	1	2	3	1	2	1	12	42

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set PS

Question No. I & E PS-009-D:

Provide the total number of "Grade 1", "Grade 2+", "Grade 2", and "Grade 3" leaks found on each of the following pipe materials for the last five calendar years:

A. Cast Iron;

B. Wrought Iron;

C. Bare Steel;

D. Pre 1971 Coated Steel;

E. Pre 1981 Plastic; and

F. 1982 Plastic.

Response:

Please see the following tables, which include mains and service lines.

A. Cast Iron

Count of Leaks		2017	2018	2019	2020	2021	Total
CAST IRON	1	8	10	9	8		**35**
	2+	8	14	12	2	1	**37**
	2	17	30	31	11	2	**91**
	3	1	1	7	2		**11**
	Total	**34**	**55**	**59**	**23**	**3**	**174**

B. Wrought Iron

Count of Leaks		2017	2018	2019	2020	2021	Total
WROUGHT IRON	1	2	1		2	1	**6**
	2+	2	2	5	1	3	**13**
	2	20	16	36	8	19	**99**
	3	1	1	1			**3**
	Total	**25**	**20**	**42**	**11**	**23**	**121**

C. Bare Steel

Count of Leaks		2017	2018	2019	2020	2021	Total
STEEL	1	213	257	211	196	199	**1,076**
	2+	262	259	236	195	190	**1,142**
	2	1,138	941	1,172	1,095	868	**5,214**
	3	52	52	59	38	13	**214**
	Total	**1,665**	**1,509**	**1,678**	**1,524**	**1,270**	**7,646**

D. Coated Steel

Count of Leaks		2017	2018	2019	2020	2021	Total
STEEL TREATED	1	37	43	35	49	43	**207**
	2+	44	52	29	33	28	**186**
	2	123	199	163	135	114	**734**
	3	20	37	16	3		**76**
	Total	**224**	**331**	**243**	**220**	**185**	**1,203**

E & F. All Plastic and Plastic Inserted. The company does not segregate pre 1981 plastic and 1982 plastic.

Count of Leaks		2017	2018	2019	2020	2021	Total
PLASTIC	1	300	364	341	319	303	**1,627**
	2+	134	165	136	121	108	**664**
	2	456	439	462	400	363	**2,120**
	3	120	94	73	14	6	**307**
	Total	**1,010**	**1,062**	**1,012**	**854**	**780**	**4,718**

Count of Leaks		2017	2018	2019	2020	2021	Total
PLASTIC INSERT	1	30	38	26	20	19	**133**
	2+	8	4	9	5	4	**30**
	2	19	17	22	29	32	**119**
	3						
	Total	**57**	**59**	**57**	**54**	**55**	**282**