I&E Statement No. 1
Witness: Rachel Maurer

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Direct Testimony

of

Rachel Maurer

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I & E Stmt. 1
R-2015-2468056
8-4-15
Harrisburg JS

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rachel Maurer. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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 EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. My educational and professional background is 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 and testimony in this proceeding is based on its responsibility to represent the public interest.

Q. DEFINE THE PUBLIC INTEREST.

A. The public interest refers to jurisdictional 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 direct testimony is to address the rate of return, including the cost of common equity, and the overall fair rate of return for Columbia Gas of Pennsylvania, Inc. (Columbia or Company).

BACKGROUND

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

A. 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. Rate of return is one of the components of the revenue requirement formula.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

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

$$RR = E + D + T + (RB \times ROR)$$

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 rate 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 the 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; and
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 the rate base, to total capital. In this case, the capital components consist of long-term debt, short-term debt and common equity. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt is able to 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 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.

<u>I&E POSITION</u>

Q. SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION IN THIS CASE.

A. I recommend the following rate of return for Columbia:

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	42.65%	5.31%	2.27%
Short-Term Debt	5.14%	1.95%	0.10%
Common Equity	52.21%	9.24%	4.82%
Total	100.00%		7.19%[1]

[1] I&E Exhibit No. 1, Schedule 1.

COMPANY POSITION

Q. SUMMARIZE THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE.

A. Company witness Paul Moul recommended the following rate of return for Columbia:

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	42.65%	5.31%	2.27%
Short-Term Debt	5.14%	2.86%	0.15%
Common Equity	52.21%	10.95%	5.72%
Total	100.00%		8.14%[2]

PROXY (BAROMETER) GROUP

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

A. A proxy group, also called a barometer group, is a group of companies that act 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 BAROMETER GROUP?

A. A barometer group cost of equity is 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 equal to that of similar risk enterprises.

A barometer group is typically utilized since the use of data exclusively from one company may be less reliable than using data from a group of

[2] Columbia Exhibit No. 400, Page 1 of 28, Schedule 1 [1 of 2].

companies. 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 particular circumstances and would therefore not be representative of similarly situated companies. The use of a barometer group has the effect of smoothing out potential anomalies associated with a single company.

Q. ARE THERE ANY ADDITIONAL REASONS FOR USING A BAROMETER GROUP IN THIS CASE?

A. Yes. Many public utility companies, like Columbia Gas of Pennsylvania, Inc., are not publicly traded and therefore lack specific market data. A barometer group provides that industry-specific market data.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR BAROMETER GROUP COMPANIES?

A. When selecting a barometer group I used the following criteria:

1. 50% or more of the company's revenues must be generated from the natural gas distribution industry;
2. The company's stock must be publicly traded;
3. Investment information for the company must be available from more than one source;

4. The company must not be currently involved in an announced merger or targeted in an acquisition; and
5. The company must have six years of historic earnings data.

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

A. Mr. Moul began his barometer group selection process with the 11 gas utilities in the Value Line Investment Survey that are not currently the target of a publically announced merger or acquisition. Mr. Moul selected AGL Resources, Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc. Mr. Moul explains that he eliminated NiSource Inc. and UGI Corporation from his barometer group due to operational differences and diversification.[3]

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

A. I selected Atmos Energy Corp., AGL Resources Inc., Laclede Group Inc., Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas, and WGL Holdings Inc. I excluded NiSource Inc. and UGI Corporation, which Mr. Moul had also excluded; and I also excluded New Jersey Resources.

[3] Columbia Statement No. 8, page 4, lines 12-19; and Exhibit No. 400, page 6 of 28.

Q. PLEASE EXPLAIN WHY YOU HAVE EXCLUDED NISOURCE INC., UGI CORPORATION, AND NEW JERSEY RESOURCES FROM YOUR BAROMETER GROUP.

A. I have excluded all three companies as they violate my first criterion that 50% or more of the company's revenues must be generated from the natural gas distribution industry.

CAPITAL STRUCTURE

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

A. The Company has claimed a capital structure of 42.65% long-term debt, 5.14% short-term debt, and 52.21% equity for the future test year ending December 31, 2016.

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

A. Mr. Moul states 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 new rates are in effect.[4]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. Yes.

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[4] Columbia Statement No. 10, page 20, line 24 to page 21, line 2.

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

A. I recommend using the Company's claimed capital structure of 42.65% long-term debt, 5.14% short-term debt, and 52.21% equity for the future test year ending December 31, 2016.[5]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's capital structure is appropriate for this proceeding as it is within the range of capital structures of my barometer group. The capital structures of the barometer group companies range from 59% debt and 41% equity to 46% debt and 54% equity.[6]

COST RATE OF LONG-TERM DEBT

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

A. Mr. Moul calculates the Company's claimed cost rate of long-term debt to be a weighted cost rate of 5.31% based on the Company's long-term debt issues expected to be outstanding at December 31, 2016.[7]

[5] Columbia Exhibit No. 400, page 10 of 28.
[6] I&E Exhibit No. 1, Schedule 2.
[7] Columbia Exhibit No. 400, page 13 of 28.

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

A. The Company's claim of 5.31% is based on prior debt issuances plus estimates of future issuances at a cost rate based on a 30-year Treasury Bond yield plus a 162 to 163 basis point spread. This spread was obtained from Reuter's Corporate Bond Spread Tables for a BBB- credit rating as of January 22, 2015.[8] At the time of the filing, the Company was estimating that it would issue a $60,000,000 note in March 2015 with a coupon rate of 4.16%. As can be seen in Columbia's response to I&E-RR-001,[9] the actual interest rate on the issue was 4.15%.

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS DUE TO THE DIFFERENCE BETWEEN THE COMPANY'S ESTIMATED AND ACTUAL COUPON RATES OF 4.16% AND 4.15%?

A. No. I have made no adjustments for this small difference as it does not change the total cost of long-term debt.

Q. DO YOU AGREE WITH THE CLAIMED COST RATE OF LONG-TERM DEBT?

A. Yes. I agree with the Company's long-term debt cost rate of 5.31% because it is within the range of implied cost rates for the barometer group of 3.13% to

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[8] I&E Exhibit No. 1, Schedule 3, page 10; Response to I&E-RR-001.
[9] I&E Exhibit No. 1, Schedule 3, page 1.

6.87%.[10] The calculation for the previously issued long-term debt is a mathematical calculation based on the coupon rate already assigned to each debt issuance.

The following table compares the estimated December 2014 future debt cost estimated in the Company's 2014 base rate case (filed March 2014) and the March 2015 future debt cost estimated in the instant case to the actual debt cost:

		Coupon Rate	**Difference**
December 2014	Projected	5.41%	
	Actual	4.43%	0.98%
March 2015	Projected	4.16%	
	Actual	4.15%	0.01%

In the instant case, the estimates of debt issuances for September 2015 and March 2016 are based on predictions of future issued amounts, dates, and cost rates. As such, I recommend that as part of its next base rate filing, Columbia supply: (1) all documentation, including all term sheets or estimates from investment bankers, supporting debt issued between this base rate case and the next base rate case; and (2) the Treasury yield as reported in the Federal Reserve Statistical Release, H.15 Selected Interest Rates and the yield spread as reported by Reuters Corporate spreads as of the dates of each issuance.

[10] I&E Exhibit No. 1, Schedule 4.

COST RATE 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. One advantage of gas storage is the ability of NGDCs to pump gas into storage during the summer months when demand for gas is 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 CLAIM FOR THE COST RATE OF SHORT-TERM DEBT?

A. The Company's proposed cost rate of short-term debt is 2.86%, which represents the Company's forecasted cost of short-term debt for the FPFTY ending December 31, 2016.[11]

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

A. Mr. Moul states that the Company obtains short-term debt from the NiSource money pool with an interest rate established by adding a margin of 1.275% to the London Interbank Offered Rate (LIBOR). For this case Mr. Moul used a LIBOR

[11] Columbia Gas Statement No. 8, page 21-22.

rate of 1.583% and when the 1.275% margin is added, Mr. Moul's short-term debt cost rate estimate is 2.858%.[12]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. No. In Columbia's prior rate case at Docket No. R-2012-2321748, the Company's claim for short-term debt was 1.90%, and in Docket No. R-2014-2406274 the Company's claim was 2.27%. For the past two years, the cost rate for Columbia's short-term debt has ranged from 0.56% to 1.28% with an average of 0.76%, which is lower than Mr. Moul's previous estimates of 1.90% and 2.27%.[13]

Mr. Moul claims that the interest rate is established as the one-month LIBOR plus 127.5 basis points. It is hard to see mathematically how that is possible as the 127.5 basis point *addition* to the LIBOR is higher than any *cost rate* the Company has experienced in the past two years (other than a cost rate of 1.28% in December of 2012).

The average spread between Columbia's claimed short-term debt rate and the one-month LIBOR for the last two years is 0.55%. The Blue Chip Financial Forecast published May 1, 2015 forecasts the three-month LIBOR rate for the first three quarters of 2016 to be 1.0%, 1.4%, and 1.7%.[14] As the fourth quarter

[12] Columbia Gas Statement No. 8, page 22, lines 1-4.
[13] Columbia Standard Data Request, Question No. GAS-ROR-016, Attachment A.
[14] As a forecast for the one-month LIBOR was unable to be found, Blue Chip's three-month forecast was used. The three-month LIBOR yield has historically been higher than the one-month enabling my short-term debt estimation to be generous.

forecast was not available, I averaged the forecast for the first three quarters to determine an overall average of 1.4%. The average spread of 0.55% in addition to the LIBOR forecast of 1.4% would result in a short-term debt cost rate of 1.95%.[15] Therefore, Columbia's current claim of the LIBOR rate of 1.583% and a 1.275% spread resulting in a short-term debt cost rate of 2.858% is overstated and unsupported.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COST RATE OF SHORT-TERM DEBT?

A. I recommend using a short-term debt cost rate of 1.95%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE A 1.95% COST RATE OF SHORT-TERM DEBT?

A. In a standard data request, Columbia presents the balance and rate for short-term debt.[16] In the past two years, the Company has had a balance of short-term debt for 10 of the 24 months. For the past two years, the weighted average cost rate of short-term debt is 1.15%. The average cost rate for the last two years (December 2012 to November 2014), regardless of whether or not Columbia had a short-term debt balance, was 0.76%. Columbia's claimed cost rate of 2.858% is not reasonable when compared with its own historical short-term debt cost rates. My

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[15] I&E Exhibit No. 1, Schedule 5.

[16] Columbia Standard Data Requests, Question No. GAS-ROR-016, Attachment A.

recommendation of 1.95% is based on Columbia's own historical spread and includes a forecasted LIBOR in recognition of the fact that interest rates are projected to increase.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY PROPOSED TO DETERMINE THE COST OF COMMON EQUITY?

A. There are four methods commonly proposed to determine the cost of common equity. The four methods are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP), and Comparable Earnings (CE) methods.

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

A. The theoretical basis for the DCF model 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 model 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 Capital Asset Pricing Model 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. The 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 stocks are riskier than debt and as a result, investors require a higher expected return on stocks than bonds. In the risk premium 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 the company group through the use of beta. The RP method does not measure the specific risk of the company.

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

A. The theoretical basis for the CE method is the economic concept of "opportunity cost," or the probable return available to investors from alternative investments of similar risk. Under this theory, when investors believe that the probable return from a given investment is not equal to that available from another investment of similar risk, the investor will shift resources to the alternative investment.

Q. IN THIS CASE, WHAT METHODS DO YOU RECOMMEND TO DETERMINE THE COST OF COMMON EQUITY?

A. I recommend using the DCF method as the primary method to determine the cost of common equity and the using results of the CAPM as a comparison to the DCF results.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF AND CAPM IN YOUR ANALYSIS.

A. I have used the DCF as the primary method for several reasons. First, it is based upon the concept that the receipt of dividends plus expected appreciation is the total return requirement determined by the market. Second, it uses the utilities' own stock prices and growth rates which are directly employed in a calculation, allowing it to be company-specific. Third, it recognizes the time value of money and is forward-looking, two criteria that match investors' expectations. Fourth, 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, not by measuring the relationship between a security's investment risk and its market rate of return. Finally, it has the most wide-spread regulatory acceptance.

I have included a CAPM analysis as a comparison because of the interest by the Commission in confirming the DCF results submitted in base rate cases by the use of a second method. I believe that out of the four commonly proposed methods identified above, other than the DCF, the CAPM should be used as the second method. Like the DCF, the CAPM is based on the concept of risk and return, the betas of the companies being analyzed allow the CAPM to be company-specific, it has widespread use in the financial investment community, and it is forward-looking. Unlike the DCF, there are several disadvantages to using the CAPM which is why it should not be used as a primary method.

Q. EXPLAIN THE CAPM'S DISADVANTAGES.

A. The relevancy of the CAPM (and therefore, the RP method) does not carry over from the investment decision-making process into the regulatory process. The CAPM and RP method 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. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolio, 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 method 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 in the future.

Q. HOW DOES THE FACT THAT ECONOMIC AND REGULATORY CONDITIONS TODAY CAN BE AND ARE OFTEN DIFFERENT FROM THE HISTORIC PERIOD AFFECT THE RESULTS FROM THE CAPM AND RP METHOD?

A. The CAPM and the RP method do not measure the current rate of return on common equity directly. Instead, the CAPM and the RP method determine the rate of return on common equity indirectly by observing the cost of debt.

An implicit assumption when using the CAPM and the RP method is that the variables determining the equity cost rate and debt cost rate are the same, which allows the analyst to apply a constant risk premium (difference between risk-free rate and the return on the market). However, the variables determining the cost rates in the two markets affect the cost rates differently, leading to a changing risk premium. The use of a constant risk premium fails to capture the effect of changing economic conditions on risk premiums over time.

While a historic risk premium is the result of a comparison of two cost rates over time, the DCF's constant growth rate is derived directly from the stock and is not a comparative factor.

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

A. Yes. An article, 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.[17] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory, the higher a stock's beta, the higher the expected return on that stock. 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 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 to invalidate the way it is used in applications."[18] 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.

[17] I&E Exhibit No. 1, Schedule 6.
[18] I&E Exhibit No. 1, Schedule 7.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP AND CE MODELS IN YOUR ANALYSIS.

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

The CE method is excluded because it is subjective as to which companies are comparable and it is debatable whether historic accounting values are representative of the future. Moreover, the Commission has long recognized the problem with this method and as a result its historical usage in this regulatory forum has been minimal.

Q. WHAT IS THE COMMISSION'S HISTORICAL TREATMENT OF THE COMPARABLE EARNINGS APPROACH?

A. Regarding the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility the Commission stated:

> The use of nonregulated companies as a comparable group for regulated firms under the comparable earnings method of computing a rate of return on common equity requires numerous unsupportable assumptions and results in a highly speculative finding.[19]

In a subsequent case, the Commission also noted National Fuel Gas Distribution Corp.'s limited use of the CE methodology:

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[19] *Pennsylvania Public Utility Commission v. Philadelphia Electric Co.* 33 PUR 4th 319, 341 (Pa PUC 1980).

> NFGD employed comparable earnings as a check on the common equity cost rates produced by its other methodology. NFGD M.B. p. 170. NFGD did not use comparable earnings as a common equity cost rate determinant. Additionally, it was noted that comparable earnings are not market related but accounting related ratios.[20]

SUMMARY OF COMPANY'S RESULTS

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

A. Mr. Moul testifies that in analyzing the Company's cost of equity, he relied on four measures: the DCF, the RP, the CAPM, and the CE method. Mr. Moul then lists the results for each measure based on his barometer group of nine gas companies:

Measure	Gas Group
DCF	10.05%
Risk Premium	11.75%
CAPM	11.90%
CE method	13.55%

Mr. Moul makes a recommendation of 10.95%, which is within his range of market-based models (DCF, RP, and CAPM). His recommendation includes a 25

[20] *Pennsylvania Public Utility Commission v. National Fuel Gas Distribution Corp.*, Docket No. R-00940021, p. 199, Order entered December 1, 1994.

basis point addition based on Mr. Kempic's claims of exemplary performance of the Company's management.[21]

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. Based upon my analysis, I recommend a cost of common equity of 9.24%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I arrived at this equity return using the DCF method. As addressed below, I used my CAPM results of 8.26% (forecasted) and 9.85% (historic) only to present to the Commission a comparison to my DCF results. My DCF analysis employed a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts.

DISCOUNTED CASH FLOW (DCF)

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the standard discrete DCF model as portrayed in the following formula:

[21] Columbia Gas Statement No. 8, page 6-7.

$K = D_1/P_0 + g$

Where:

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

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by half of the expected growth rate in order to account for changes in the dividend paid in period one.[22] As forecasts for each company in my barometer 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 short-term anomalies and "stale" data series. For the purpose of 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 barometer group:

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[22] The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain. It could occur next month, or in the twelfth month. On average, it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by ½ the expected growth rate is appropriate.

Eight Company Barometer Group	Dividend Yield
Spot	3.61%
52-week average	3.69%
Average	3.65%[23]

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

A. I have examined the earnings growth forecasts.

Q. PLEASE EXPLAIN YOUR USE OF EARNINGS GROWTH FORECASTS.

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

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

A. The following table presents the expected growth rates for the eight-company barometer group:

[23] I&E Exhibit No. 1, Schedule 8, page 2.

Company	Average Growth Rate
AGL Resources	5.23%
Atmos Energy	6.90%
Laclede Group	6.53%
Northwest Natural Gas	4.38%
Piedmont Natural Gas	5.35%
South Jersey Industries	6.38%
Southwest Gas	4.48%
WGL Holdings Inc.	5.48%
Average	5.59%[24]

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE RESULTS FOR THE FIVE-YEAR PROJECTED GROWTH RATES?

A. Yes. While these 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.

Q. PLEASE EXPLAIN.

A. An article authored by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong evidence of earnings forecasts being higher than actual earnings.[25] In the

[24] I&E Exhibit No. 1, Schedule 8, page 3.

[25] 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.

spring of 2010, *McKinsey On Finance* presented an article reporting that after a decade of stricter regulation, analysts' forecasts are still overly optimistic.[26]

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.

Q. WHAT METHODOLOGY DO YOU RECOMMEND TO DETERMINE A MORE APPROPRIATE LONG-TERM GROWTH RATE?

A. If historical earnings and dividend growth rates can be assumed by investors to be indicative of future growth, I would recommend using a log-linear regression analysis.

Q. WHAT IS A LOG-LINEAR REGRESSION FOR THE PURPOSES OF DETERMINING A GROWTH RATE?

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

A. A log-linear regression is a standard time-series linear regression in which data points are plotted as natural logarithms.

Linear regression analysis assumes that a linear relationship exists between two variables. This means that if the two variables were plotted on a graph, a straight line would take shape, and a best fit line could be calculated. However, in certain cases, raw growth data was plotted and instead of a straight line being formed, a hyperbola was formed. In these cases, the data must be transformed before a regression, or a best fit line, can be calculated. To create a linear relationship with the growth data, the earnings per share must be transformed by the natural log, or log with a base e. The log transformation converts the compound growth pattern to a linear growth pattern. The natural log data is then plotted and the slope of the best fit line is determined; this slope is the growth rate, but in natural log form. To make the slope meaningful, the antilog is calculated to arrive at a growth rate.

Q. WHEN CAN A LOG-LINEAR REGRESSION ANALYSIS BE USED?

A. A log-linear analysis can be used when earnings and dividend growth rates have been relatively stable and if investors expect these trends to continue.

Q. HAVE YOU USED A LOG-LINEAR REGRESSION ANALYSIS IN THIS PROCEEDING?

A. No.

Q. WHY HAVE YOU NOT USED A LOG-LINEAR REGRESSION ANALYSIS IN THIS PROCEEDING?

A. I have not used a log-linear analysis because the historical growth in earnings is not indicative of the future growth in earnings for the gas utility industry at this point in time.

Q. PLEASE EXPLAIN.

A. Historically, gas utilities had a stable rate at which capital projects were completed. However, much of the gas utility industry's pipe has now reached the end of its useful life and needs to be replaced. Beginning a few years ago, the industry commenced plans to aggressively replace the majority of this pipe within the next twenty years. This translates into replacing fully depreciated plant with new plant, thereby increasing rate base. Rate of return is applied to this increased rate base, thereby increasing earnings. It is this unusual growth in earnings that causes the growth rate to be different from its historical rates.

The magnitude of the replacement of depreciable plant also causes a bigger increase in earnings than the relatively smaller, regular capital projects. Therefore at this time, a log-linear analysis has not been performed as the historical growth is not indicative of future growth.

Q. CAN A LOG-LINEAR ANALYSIS BE USED IN THE FUTURE?

A. Yes. After sufficient time has passed (e.g., five years of historical data or two years of no change in growth), and if a new trend emerges, a log-linear analysis will again be performed to arrive at a representative growth rate. This is because the historical rate of pipe replacement will again be indicative of the future rate of pipe replacement.

Q. WHAT IS THE RESULT OF YOUR DISCOUNTED CASH FLOW ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELDS AND GROWTH RATES?

A. The result of my DCF analysis is 9.24%[27] and is calculated as follows:

K	=	D_1/P_0	+	g
9.24%	=	3.65%	+	5.59%

<u>CAPITAL ASSET PRICING MODEL (CAPM)</u>

Q. EXPLAIN YOUR USE OF THE CAPM MODEL.

A. In my discussion of an appropriate equity cost rate for Columbia, I have included a CAPM analysis as a result of an increased interest by the Commission in confirming the DCF results submitted in base rate cases by the use of a second method.

[27] I&E Exhibit No. 1, Schedule 8, page 1.

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the standard 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
β	=	Beta measures the systematic risk of an asset

The CAPM formula above is a form of the more general risk premium approach and is based on modern portfolio theory.

Q. WHAT IS BETA AS EMPLOYED IN YOUR USE OF THE CAPM MODEL?

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 have a beta of 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. WHAT BETA DID YOU CHOOSE FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my barometer group of eight natural gas distribution companies, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for the eight company barometer group is 0.78.[28]

Q. WHAT TIME PERIODS HAVE YOU CHOSEN FOR YOUR HISTORIC CAPM ANALYSIS?

A. My historic CAPM uses a risk-free rate and a market risk premium calculated over 5, 10, 20, 40, and 62 years.

Q. WHY HAVE YOU SELECTED THESE TIME PERIODS FOR YOUR HISTORIC CAPM?

A. I have selected the above time periods to represent a variety of investor experiences and time horizons. The 62-year time period represents the longest time period available from the U.S. Treasury for the 10-year Treasury Bond yield. The 40 and 20-year time periods coincide with the average useful lives of a utility's assets. The 10-year time period corresponds with the 10-year Treasury Bond I have employed. The 5-year time period corresponds with time period the DCF growth rates are projected.

[28] I&E Exhibit No. 1, Schedule 9.

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

A. For my historic CAPM analysis, I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Bonds. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free yield, this yield 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 yield exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with the 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 chose to use the yield on the 10-year Treasury Bond because it balances the shortcomings of the other two alternatives. Historically the geometric average for the yield on the 10-year Treasury Bond has been as follows:

Time period	Geometric Average
5 years	2.49%
10 years	3.19%
20 years	4.13%
40 years	6.07%
62 years	5.45%
Average	4.27%[29]

[29] I&E Exhibit No. 1, Schedule 10, page 2 of 3.

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

A. I have used a historical return for the S&P Composite Index as a benchmark for the expected return on the overall stock market. This historical component can vary widely depending on the historic period used. Using the geometric mean of historic returns, I calculated the following results:

Time period	Return[30]
5 years	16.06%
10 years	7.95%
20 years	9.99%
40 years	12.26%
62 years	10.82%
Average	11.42%

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

A. The forecasted yield on the 10-year Treasury Bond is expected to range between 2.00% and 4.40% over the next five years.[31] For my forecasted CAPM analysis I chose 2.75%, which is the average of the yields.

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

[30] I&E Exhibit No. 1, Schedule 10, page 3 of 3.
[31] I&E Exhibit No. 1, Schedule 11, page 2 of 3.

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1500 stocks and the S&P 500. As shown in Schedule No. 11,[32] Value Line expects its universe of 1500 stocks to have an average yearly return of 9.89% over the next three to five years, based on a forecasted dividend yield of 2.10% and a yearly index appreciation of 35%. Yahoo! Finance expects the S&P 500 index to have an average yearly return of 9.73% over the next five years, based upon Barron's forecasted dividend yield of 2.08% and Yahoo!'s expected increase in the S&P 500 index of 7.65%.

Q. WHAT ARE THE EXPECTED RETURNS ON THE OVERALL STOCK MARKET BASED ON YOUR FORECASTED AND HISTORIC ANALYSIS?

A. The expected returns on the overall market are 11.42%[33] for my forecasted analysis and 9.81%[34] for my historical analysis.

Q. WHAT ARE THE COST OF EQUITY RESULTS FROM YOUR FORECASTED AND HISTORIC CAPM ANALYSES?

A. The results of these two analyses are as follows:

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[32] I&E Exhibit No. 1, Schedule 11, page 3.
[33] I&E Exhibit No. 1, Schedule 10, page 3.
[34] I&E Exhibit No. 1, Schedule 11, page 3.

	CAPM Cost of Equity
Forecasted	8.26%[35]
Historic	9.85%[36]

Q. HOW DID YOU INCORPORATE THESE RESULTS INTO YOUR OVERALL COST OF EQUITY?

A. I have included the results of my CAPM analysis in my overall cost of equity calculation only as a comparison to my DCF result. The DCF model measures the cost of equity directly by measuring the discounted present value of future cash flows of a company and it is these cash flows that actually pay dividends to shareholders. The Commission has expressed interest in seeing the results of other models to confirm the results of DCF. The CAPM is a commonplace cost of equity measure and I have used its results as a point of comparison to the results of the DCF.

Q. WHY DID YOU NOT GIVE THESE RESULTS A SPECIFIC WEIGHT IN DETERMINING YOUR COST OF COMMON EQUITY?

A. I have not given these results a specific weight in determining my cost of common equity because of the flaws in the CAPM model that I have expounded upon

[35] I&E Exhibit No. 1, Schedule 11, page 1.
[36] I&E Exhibit No. 1, Schedule 10, page 1.

earlier in my testimony. The CAPM model is flawed, first, theoretically because it measured the cost of equity indirectly through the cost of a risk-free asset, and second, in practice because it can be manipulated by the time period used to calculate the overall market return.

CRITIQUE OF COMPANY RECOMMENDATION

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

A. No. Mr. Moul's cost of equity recommendation is overstated for several reasons. First, by using the results of his DCF, CAPM, and RP in presenting his final recommendation, Mr. Moul gives undue weight to his CAPM and RP results. Second, Mr. Moul makes several unsupported manipulations to either the inputs to or the results of his analyses, all of which serve to inflate his recommendation. Third, while apparently not used in his final cost of equity recommendation, Mr. Moul also presents the results of a CE analysis that contains limitations and is faulty. Finally, Mr. Moul proposes to add 25 basis points to his cost of equity in recognition of the Company's claimed high quality performance.

WEIGHTS GIVEN TO THE CAPM AND RP METHODS

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 methodology in order for it to have a point of comparison to the results of the DCF calculation, I *am* opposed to giving the CAPM and RP equal weight. For the reasons I previously discussed in this testimony, it is inappropriate to give the CAPM and RP models equal weight as Mr. Moul has done in creating a "range of market-based measures."[37] 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.

<u>**CE METHOD**</u>

Q. WHAT ARE THE LIMITATIONS OF THE COMPARABLE EARNINGS APPROACH?

A. The CE approach employed by Mr. Moul compares projected returns of companies of dissimilar business and financial risk.

Q. EXPLAIN HOW MR. MOUL'S CE APPROACH IS FAULTY.

A. The companies in Mr. Moul's analysis are not utilities and therefore, they are too dissimilar to be used in a Comparable Earnings analysis. The companies in Mr. Moul's CE barometer group are simply not comparable to gas utilities in terms of their business risk or financial risk profile. Gas utilities are monopolies and so 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 barometer group operate in an unregulated competitive environment with a higher

[37] Columbia Gas Statement No. 8, page 6, lines 5-6.

level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

<u>MR. MOUL'S UNNECESSARY AND UNSUPPORTED ADDITIONAL EQUITY ADJUSTMENTS</u>

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS COST OF EQUITY ANALYSIS?

A. With respect to his DCF analysis, Mr. Moul adjusts his indicated cost of common equity upward by 72 basis points to account for leverage. Mr. Moul makes a similar unsupported adjustment within his CAPM methodology by inflating the betas used in his CAPM analysis.

Mr. Moul then makes several unsupported adjustments to his indicated cost of equity results all premised on the perceived "riskiness" of Columbia in comparison to his proxy group. Mr. Moul adjusts his CAPM indicated cost of common equity upward by 114 basis points to reflect Columbia's claimed higher business risk due to its small size relative to his proxy group. Mr. Moul also adjusts the results of his DCF and RP analyses upward by 50 basis points to account for Columbia's claimed weaker credit quality relative to his proxy group. Mr. Moul then offers his risk specific assessment of Columbia based upon the existence of local gas production, the overlapping service territories in western Pennsylvania, the proximity of Columbia to interstate pipelines, and customers' threat of bypass.

Finally Mr. Moul adjusts his overall indicated cost of common equity upward by 25 basis points to reflect Columbia's claim of exemplary performance by the Company's management.

DIVIDEND YIELD ADJUSTMENT

Q. WHAT DIVIDEND YIELD ADJUSTMENT HAS MR. MOUL PROPOSED IN HIS ANALYSIS?

A. Mr. Moul has proposed an ex-dividend adjustment to the dividend yields of his barometer group. Mr. Moul adjusts the "month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date."[38]

Q. IS MR. MOUL'S EX-DIVIDEND ADJUSTMENT APPROPRIATE?

A. No. Mr. Moul's ex-dividend adjustment is inappropriate for three reasons. First, my review of the academic literature fails to uncover any support for the application of an ex-dividend adjustment to the dividend yield in the DCF formula as proposed by Mr. Moul. Second, Mr. Moul has not provided any evidence in his testimony that suggests investors make this adjustment in the context of the DCF model. Finally, I am not aware of any financial publications that provide ex-dividend adjusted yields to investors that might be used for their financial investment decision making. Arguably, if such information were an important

[38] Columbia Statement No. 8, page 24, lines 14-16.

factor in an investor's decision making process, main-stream financial publications would include it on a regular basis.

Q. WHAT IS MR. MOUL'S DIVIDEND YIELD PRIOR TO HIS ADJUSTMENT?

A. Mr. Moul calculated a dividend yield of 3.48% for the Gas Group before adjustments.[39]

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

A. Without Mr. Moul's use of a dividend yield adjustment, leverage adjustment, and credit quality adjustment, his DCF would consist of a dividend yield of 3.48% and an average growth rate of 5.25%, which results in an 8.73% cost of equity.

LEVERAGE (MARKET-TO-BOOK) ADJUSTMENT

Q. WHAT OTHER ADJUSTMENTS HAS MR. MOUL ATTACHED TO THE RESULT OF HIS PROPOSED DCF ANALYSIS?

A. Mr. Moul proposes to make a 72 basis point "leverage" adjustment to the results of his DCF analysis to account for applying a market valued cost of equity to a book valued equity capital measure.[40]

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[39] Columbia Statement No. 8, page 25.
[40] Columbia Gas Statement No. 8, pages 31-36.

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 RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value. This is done by comparing a company's equity market value to a company's equity book value.

Q. IS THE TERM "LEVERAGE" APPROPRIATE FOR THIS TYPE OF ADJUSTMENT?

A. No. Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he propose to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul is proposing to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's equity. Currently, there is no term in academic journals or text books that describes this type of adjustment.

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

A. Mr. Moul theorizes that if regulators use the results of the DCF to compute the weighted average cost of capital based on a book value capital structure used for ratemaking purposes, the utility will not, by definition, recover its risk-adjusted capital cost. Mr. Moul believes 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.[41]

Q. HOW DOES MR. MOUL CALCULATE THE LEVERAGE ADJUSTMENT USED IN HIS ANALYSIS?

A. Mr. Moul states:

> I know of no means to mathematically solve for the 0.72% (9.55%-8.83%) leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.72% adjustment is merely a convenient way to compare the 9.55% return computed directly with the Modigliani & Miller formulas to the 8.83% return generated by the DCF model based on a market value capital structure.[42]

Q. HOW DOES MR. MOUL CALCULATE THE 9.55% RETURN HE CLAIMS IS COMPUTED DIRECTLY WITH THE MODIGLIANI & MILLER FORMULAS?

A. Mr. Moul uses the following formulas found in Columbia Exhibit No. 400, page 17 of 28:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D/E) - (ku - d)\ P/E$$

and $$ke = ku + (((ku - i)\ 1\text{-}t)\ D/E) + (ku - d)\ P/E$$

[41] Columbia Statement No. 8, pages 31-32.
[42] Columbia Statement No. 8, page 33, lines 3-8.

Where:

ku = cost of equity for an all-equity firm

ke = market determined cost equity

i = cost of debt

d = dividend rate on preferred stock

D = debt ratio

P = preferred stock ratio

E = common equity ratio

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

A. No. Mr. Moul's adjustment is inappropriate for several reasons, including rating agency characterization of financial risk, Commission precedent, and lack of support in academic literature.

Q. PLEASE 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. True financial risk resides in the income statement, and is a function of the actual amount of interest expense and income volatility. Therefore, no matter how the company's investments are valued in the market place, the financial risk does not change because it is based on the company's financial situation as reflected in its income statement.

Q. HOW DOES COMMISSION PRECEDENT AFFECT MR. MOUL'S USE OF A LEVERAGE ADJUSTMENT.

A. There are several cases in which this same "leverage adjustment" has been rejected. First, the Commonwealth Court in *Blue Mountain Consolidated Water Company v. Pennsylvania Public Utility Commission*, 57 Pa. Commonw. 363, 426 A.2d 724 (1981), remanded the case to the Commission "for clarification of findings concerning fair rate of return." On remand, the Commission responded to the Court's request for clarification by identifying seven principles that were applied to analyze the company's required and lawful rate of return. The third principle identified by the Commission states in full:

> (3) Market price-book value ratios are not a goal of regulation but a result of regulation, general economic factors and individual company's characteristics of management, operations and perceived future. In general, we view a market-book ratio in the area of one-to-one as appropriate for regulated industry.[43]

Second, in *Pennsylvania Public Utility Commission v. Metropolitan Edison Co.*, Docket No. R-00061366 (Order entered January 11, 2007), p. 34, the Commission did not accept the Company's financial risk increment related to the

[43] *Pennsylvania Public Utility Commission v. Blue Mountain Consolidated Water Company*, Docket No. R-78100686, 55 P.U.R. 502, 503-04 (Pa PUC 1982).

leverage difference between market capital structures and book value capital structures.

Third, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, 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."

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, 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."

Q. DISCUSS THE LACK OF SUPPORT IN ACADEMIC LITERATURE FOR MR. MOUL'S LEVERAGE ADJUSTMENT.

A. Mr. Moul cites to Modigliani and Miller's research on the subject of capital structure and cost of capital as justification for his leverage adjustment. However, Mr. Moul has misinterpreted Modigliani and Miller's theory and used it in a way the researchers never advocated.

Modigliani and Miller's research was geared primarily at understanding company capital investment behavior, not the financial risk associated with a stock's market price divergence from its book value. Also, the adjustment and formula employed by Mr. Moul cannot be found in the research he cites.

Q. EXPLAIN FURTHER WHAT THE WORK OF MODIGLIANI AND MILLER STATES ABOUT THE EFFECT OF THE TYPE OF CAPITAL EMPLOYED (DEBT OR EQUITY) UPON THE VALUE OF THE FIRM.

A. The work of Modigliani and Miller actually supports the conclusion opposite to that reached by Mr. Moul, namely that "the market value of any firm is independent of its capital structure."[44] Furthermore, as they state, "the value of any firm must be independent of its financial structure."[45]

Q. ARE YOU AWARE OF ANY OTHER ACADEMIC LITERATURE THAT SUPPORTS MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. I am not aware of any other academic literature that supports Mr. Moul's leverage adjustment.

Q. ARE THERE FLAWS IN THE FORMULAS MR. MOUL USES IN HIS ANALYSIS?

A. Yes. First, the formulas employed by Mr. Moul do not appear anywhere in the research he cites. Second, his formula to determine the cost of equity of a 100%

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[44] Modigliani, Franco and Miller, Merton H. "The Cost of Capital, Corporation Finance, and the Theory of Investment" *American Economic Review*, June 1958, p. 268.

[45] Modigliani, Franco and Miller, Merton H. "The Cost of Capital, Corporation Finance, and the Theory of Investment: Reply" *American Economic Review*, June 1965, p. 525.

equity firm (ku) does not actually determine the cost of equity of a 100% equity firm, but instead, the formula assumes the cost of equity of a 100% equity firm to be 7.94%. The effect of the assumed "ku" rate of 7.94% is amplified by its presence in the formula for the market determined cost of equity (ke).

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. Yes. *Value Line* presents, in its publishing, the book value debt and equity ratios of the utilities, not the market value ratios which demonstrates that investors base their decisions on book value debt and equity ratios for the regulated utilities and no adjustment is needed.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE LEVERAGE ADJUSTMENT.

A. I recommend the rejection of the leverage adjustment because the formula used by Mr. Moul is faulty, there is no academic support for such an adjustment in a DCF setting, Commission precedent does not unequivocally support its use, true financial risk is a function of the amount of interest expense, and capital structure information provided investors through *Value Line* is that of book values, not market values.

INFLATED CAPM BETAS

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 0.78 to 0.90 that he used to enhance his DCF returns, through a financial risk or leverage adjustment.[46] 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.

SIZE ADJUSTMENT

Q. WHAT IS MR. MOUL'S SIZE ADJUSTMENT?

A. Mr. Moul adds 114 basis points to his CAPM indicated cost of common equity because he believes that as the size of a firm decreases, its risk and required return increases.[47]

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[46] Columbia Statement No. 8, pages 43-44.
[47] Columbia Statement No. 8, pages 46-47.

Q. WHY IS MR. MOUL'S SIZE ADJUSTMENT UNNECESSARY?

A. Mr. Moul's size adjustment is unnecessary because the technical literature supporting investment adjustments relating to the size of a company is not specific to the utility industry and, therefore, has no relevance to this proceeding. Furthermore, making an adjustment based on the technical literature of SBBI would be in error because it is not specific to utilities and is unpredictable.

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

A. Yes. I&E Exhibit No. 1, Schedule No. 12, presents an article by Dr. Annie Wong, that 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 industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[48]

Columbia 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 to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

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

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

A. Mr. Moul's CAPM result would be 9.83% without his size adjustment and inflated betas. The calculation is repeated below without Mr. Moul's adjustments:

Rf	+	ß	*	(Rm-Rf)	+	size	=	K
3.75%	+	.78	*	(7.79%)	+	0%	=	9.83%

RISK ANALYSIS

NATURAL GAS RISK FACTORS

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING NATURAL GAS RISK FACTORS FOR COLUMBIA.

A. Mr. Moul states that Columbia is risky for multiple reasons. First, he testifies that Columbia operates in a unique situation in western Pennsylvania with overlapping service territories which creates competition.

Second, Mr. Moul maintains that Columbia is exposed to bypass risk due to six interstate pipelines in its service territory. Mr. Moul further maintains that the Marcellus Shale formation will cause the situation to become more intense.[49]

Third, Mr. Moul claims that neither the weather normalization adjustment mechanism (WNA) nor the Distribution System Improvement Charge (DSIC)

[49] Columbia Statement No. 8, pages 7-8.

have an effect on Columbia's cost of capital as other companies in his Gas Group have similar mechanisms.[50]

Fourth, Mr. Moul discusses large volume customers, and the risks associated with that class of customers, including attrition, bypass, fuel switching, and competition.[51]

Fifth, Mr. Moul claims that Columbia's proposed construction program will affect its risk profile.[52]

Finally, Mr. Moul discusses several categories of risk including credit quality.[53] Mr. Moul compares the Company, the Gas Group, and the S&P Public Utilities using these categories and concludes that Columbia's "risk is higher than the Gas Group," and that, "[o]n balance, the cost of equity measured with the Gas Group data will provide an understatement of the Company's cost of equity."[54]

For all these reasons Mr. Moul opines that Columbia is riskier than the barometer group, and believes this should be taken into consideration when determining the rate of return.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE RISKS IN WESTERN PENNSYLVANIA?

[50] Columbia Statement No. 8, pages 8-10.
[51] Columbia Statement No. 8, pages 10-11.
[52] Columbia Statement No. 8, pages 11-12.
[53] Columbia Statement No. 8, pages 12-18.
[54] Columbia Statement No. 8, page 18, lines 12-13 and 16-17.

A. Mr. Moul's claims regarding competition, bypass risk, and the Marcellus Shale are overstated. First, Columbia has no more risk than the other western Pennsylvania NGDCs such as Equitable, Peoples, and Peoples TWP, and the risk of competition and bypass has existed for a long time. The Commission has never granted these western Pennsylvania NGDCs an additional return on equity to compensate for risk and should not start doing so now. Also, the Commission has launched a generic investigation into gas-on-gas competition at Docket No. I-2012-2320323. This investigation may determine whether or not gas-on-gas the competition should be permitted to continue.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE WNA AND DSIC?

A. Mr. Moul argues that neither the WNA nor the DSIC have an effect on risk because the barometer group companies have similar mechanisms. Although some of the barometer group companies may have mechanisms similar to that of Pennsylvania's DSIC, they do not all cover the same rate base items. In addition to a WNA and DSIC, the Company also employs a non-reconcilable Fully Projected Future Test Year (FPFTY), a fact Mr. Moul does not mention. The combination of a WNA, DSIC, and FPFTY mechanisms are seen as a positive by the credit rating agencies and investors because there will be a more timely collection of investments. The DSIC allows the Company to avoid waiting until a project is complete before receiving a return and instead allows the Company the ability to collect a return of and on its investment for anticipated projects. This is a substantial change in the regulatory process, which *reduces* risk because not only is the Company receiving the return more timely, it is also essentially signaling to investors that these projects have been approved for rate recovery. This approval reduces the risk that the Company might invest in something that the Commission will not allow the Company to recover for, which in turn reduces the risk of investors not receiving a return. The FPFTY allows the Company to include projected expenses and projects in its rates and allows rates to be forward looking and not recovering only expenses that have already been incurred. The DSIC, WNA, and FPFTY are reductions to risk that Mr. Moul fails to account for in his analysis. Additionally, Moody's recently published an article titled *Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles* which states, "We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow."[55]

Q. WHAT COMMENTS DO YOU HAVE REGARDING LARGE INDUSTRIAL AND COMMERCIAL CUSTOMERS' RISKS?

A. Mr. Moul argues that the Company's risk profile is influenced by these customers through the risk of attrition, bypass, fuel switching, and competition.[56]

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[55] *Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles*, Moody's Investor Service, Infrastructure and Project Finance, March 10, 2015.

[56] Columbia Statement No. 8, pages 10-11.

First, all gas companies are at risk of fuel switching, therefore there is no additional risk to Columbia.

Finally, the gas-on-gas competition is not a new development for Columbia's service territory, and NGDCs in western Pennsylvania have not been granted a higher return for this competition in the past.

Q. WHAT COMMENTS DOES MR. MOUL HAVE REGARDING CREDIT QUALITY?

A. Mr. Moul describes Columbia's parent company, NiSource's credit worthiness.[57] The table below summarizes Mr. Moul's comparisons of credit qualities of the different groups he analyzes:

Company	Moody's Rating	S&P Rating
NiSource	Baa2	BBB-
Gas Group	A2	A-
S&P Public Utilities	A3	BBB+

Mr. Moul concludes that the bond rating of NiSource, the Company's ultimate parent, is below that of the Gas Group, which indicates higher credit quality risk.[58]

[57] Columbia Statement No. 8, page 14.
[58] Columbia Statement No. 8, page 18, lines 13-14.

Q. DO YOU AGREE WITH MR. MOUL'S STATEMENTS REGARDING COLUMBIA'S CREDIT QUALITY?

A. No. The credit quality of NiSource is not appreciably related in this case to the credit quality of Columbia. NiSource has been evaluated by both Moody's and S&P as a collective of its various subsidiaries including Columbia Energy Group (CEG), Northern Indiana Public Service Co. (NIPSCO), and Bay State Gas Co. and as such, the credit quality of NiSource cannot be attributed solely to Columbia.

Q. PLEASE SUMMARIZE YOUR COMMENTS REGARDING COLUMBIA'S NATURAL GAS RISK.

A. A review of the information associated with Mr. Moul's claims of risk shows that Columbia is not as risky as Mr. Moul would lead one to believe. The western part of Pennsylvania is not new to competition, risk mitigation adjustments are in place for residential customer usage, and the support for the large industrial and commercial customers' risk leads to a conclusion opposite of Mr. Moul's.

MANAGEMENT RECOGNITION POINTS

Q. WHAT IS THE COMPANY'S REQUEST REGARDING MANAGEMENT RECOGNITION POINTS?

A. Mr. Moul proposes to add 25 basis points to his recommended cost of equity in recognition of the Company's claimed high quality management performance.[59] Mr. Moul relies upon the testimony of Mr. Kempic to support his additional 25 basis point boost to the requested return on equity.

Q. WHAT IS MR. KEMPIC'S TESTIMONY REGARDING MANAGEMENT EFFECTIVENESS?

A. Mr. Kempic testifies to areas of management effectiveness including Columbia's pipeline replacement program, pipeline safety enhancements, customer satisfaction, and its low income and customer programs. Mr. Kempic refers to Columbia witness Davidson for details concerning the pipeline replacement and safety enhancements. Mr. Kempic has looked at the Commission's Management Audit reports for other gas companies, the most recent Utility Consumer Activities Report and Evaluation (UCARES) published by the Bureau of Consumer Services (BCS), the most recent Universal Service and Collections Report by BCS and the Company's third party survey contractors: Metrix/Matrix, Thoroughbred Research and J.D. Powers to support its claim of management effectiveness. Finally,

[59] Columbia Statement No. 8, page 5, lines 20-22.

Mr. Kempic references the Company's CAP program has the lowest CAP payment plan and the lowest monthly average CAP bill.[60]

Q. DO YOU AGREE WITH THE 25 BASIS POINT ADDITION TO THE RATE OF RETURN PROPOSED BY MR. MOUL?

A. No. The 25 basis point addition to the rate of return is unnecessary and unmerited. The Company's performance does not rise to the level that merits 25 basis points recognition or $1,491,234 million additional net income.[61]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM REGARDING ITS PIPELINE REPLACEMENT PROGRAM AND PIPELINE SAFETY ENHANCEMENTS AS SUPPORT FOR A HIGHER RETURN ON EQUITY?

A. No. As discussed by Mr. Kline in I&E Statement No. 4, Columbia may have replaced more miles of bare steel pipeline than its peers but it also has more miles of bare steel in the ground than most of its peers. Mr. Kline concludes that when the amount of bare steel pipeline replaced is viewed as a percent of the total bare steel pipeline Columbia has in the ground, Columbia is not ahead of its peers. Mr. Kline continues his discussion of Columbia's pipeline replacement by demonstrating Columbia's historically poor performance in pipeline replacement

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[60] Columbia Statement No. 1, pages 17 to 28.

[61] Based on the Company's claimed capital structure, a 25 basis point change in the return on equity equates to a 13 basis point change in the overall return which when applied to the Company's claimed rate base is a $1,491,234 change in net income.

and stating that the progress Columbia has made since 2006 was either required by the Pipeline and Hazardous Materials Safety Administration regulations or developed to address concerns identified by the Commission's Gas Safety Division.

Although Columbia may have made progress in replacing its pipeline, a replacement percent in line with its peers and done to satisfy current regulations does not qualify it for an increased return on equity for management performance.

Q. DO YOU AGREE WITH MR. KEMPIC'S EVALUATION OF THE COMMISSION'S MANAGEMENT PERFORMANCE AUDIT REPORTS?

A. No. Mr. Kempic compares the assessments of each company's report but fails to note the timing differences between the reports. The most recent management audits for each company were completed as follows:

Company	Month Report Completed
Columbia	August 2013
Equitable	June 2010
NFG	May 2012
PECO Energy	October 2014
Peoples	March 2010
Peoples TWP	April 2009
PGW	February 2009
UGI Gas, UGI Central Penn, and UGI Penn Natural	May 2012

As can be seen, the dates the reports were completed range from February 2009 to October 2014. To compare Columbia's Management Audit from August 2014 to Peoples TWP's audit in April 2009 is comparing data that is five years apart. The vast time difference between reports causes them to not be comparable and therefore Mr. Kempic's conclusion that "Columbia's performance exceeds that of its peers"[62] is invalid.

[62] Columbia Statement No. 1, page 18, lines 10-11.

Q. **DO YOU AGREE WITH MR. KEMPIC'S CONCLUSION THAT THE UCARES AND THE UNIVERSAL SERVICE AND COLLECTIONS REPORT PUBLISHED BY BCS DEMONSTRATE THAT COLUMBIA'S PERFORMANCE WAS EXCELLENT?**

A. No. The BCS Customer Service Performance report provides more data than Mr. Kempic includes in his analysis. In some areas the Company does come above average but in some it is average, and in some it is below average.

Q. **DO YOU AGREE WITH MR. KEMPIC THAT THE COMPANY'S THIRD PARTY SURVEY CONTRACTORS: METRIX/MATRIX, THOROUGHBRED RESEARCH AND J.D. POWERS TO SUPPORT ITS CLAIM OF MANAGEMENT EFFECTIVENESS?**

A. No. The Company's third party survey contractors: Metrix/Matrix, Thoroughbred Research and J.D. Powers are not helpful because similar data is not presented on the other NGDC's.

Q. **ARE THE COMPANY'S CAP BILL AFFORDABILITY AND MONTHLY AVERAGE CAP BILL STATISTICS ALONE A SUFFICIENT MEASURE OF THE COMPANY'S TREATMENT OF ITS LOW-INCOME CUSTOMERS?**

A. No, the BCS' Universal Service and Collections Report contains other data points that measure a Company's treatment of its low-income customers. For example, Columbia has the most expensive average LIURP job cost at $6,792, which is $1,510 more than the next most expensive average LIURP job on UGI Penn Natural Gas. Columbia is average among its peer with regard to its CAP participation rate of 30% of low-income customers. Columbia Gas also has one of the most expensive CAP programs, second only to Philadelphia Gas Works in gross cost and third in cost per participant.

Q. IF COLUMBIA HAD DEMONSTRATED MANAGEMENT PERFORMANCE BEYOND THAT OF ITS PEERS WOULD YOU AGREE WITH MR. MOUL'S 25 BASIS POINT INCREASE TO THE RETURN ON EQUITY?

A. No. In addition to Columbia not demonstrating that its pipeline replacement, customers service, or low-income programs merit a 25 basis point addition, Columbia should not recognition for management performance through extra return on equity points because it is already proposing to recover its claimed management incentive program through expenses. Moreover my recommended return on equity recognizes the beneficial revenue impact of the FPFTY.

Q. PLEASE EXPLAIN.

A. Columbia has included a $1,735,000 claim for its management incentive in this case. Therefore, ratepayers are already paying for management's "efficiency" through its claimed operating expenses. To award management efficiency points through a higher return on equity, while also allowing the Company's claim for this through operating expenses results in charging ratepayers twice for the same "efficiency" claim.

Columbia provides for an incentive payout opportunity as follows:

> [T]he incentive payout opportunity is two-thirds discretionary and one-third non-discretionary. The discretionary portion of the incentive program is based on performance management linked to goals including customer, employee, process/capability, and financial goals for Columbia Gas.[63]

Ratepayers should not be asked to pay for management efficiency twice. Columbia also receives return dollars for efficiency by simply being efficient. When costs are cut or other efficiencies occur that reduce expenses, such as replacing leaky pipes, management thereby decreases expenses and increases net income (or return).

Additional management efficiency points are not necessary as Columbia is already being rewarded for efficiencies.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MANAGEMENT EFFICIENCY POINTS?

A. I recommend that the additional 25 basis points be disallowed. As described above, Columbia is already recovering money from rate payers through its operating expenses; therefore, the additional 25 basis points proposed are not warranted.

[63] I&E Exhibit No. 1, Schedule 13, page 2; Response to I&E-RE-049.

Q. WHAT EFFECTS DO MR. MOUL'S ADJUSTMENTS HAVE ON THE REVENUE REQUIREMENT?

A. Mr. Moul's adjustments for leverage, size, credit quality, management performance, and his adjustments to the dividend yield, beta, and the DCF growth rates all combine to inflate his overall rate of return recommendation. Without any adjustments, the results of the models Mr. Moul has chosen would be as follows:

DCF	D/P	+			g	=	K
	3.48%	+			5.25%	=	8.73%
RP	I	+			RP	=	K
	4.75%	+			6.50%	=	11.25%
CAPM	Rf	+	Beta	x	(Rm-Rf)	=	K
	3.75%	+	0.78	x	7.79%	=	9.83%

The average of all three methods is 9.94%. The effect of the overall rate of return on the revenue requirement can be substantial depending on the size of the rate base. Below is an illustration of the effect a change in the overall rate of return can have on the revenue requirement using Columbia's rate of return data as filed and the average of the three market-based models Mr. Moul has chosen to use without any adjustments.

Company Request	Capital Structure (A)	Cost Rate (B)	Weighted Cost (A)*(B)
Long-Term Debt	42.65%	5.31%	2.27%
Short-Term Debt	5.14%	2.86%	0.15%
Equity	52.21%	**10.95%**	5.72%
Total	100.00%		8.14%
Rate Base = $1,080,408,495			
		Total x Rate Base = Net Income	**$87,945,252**

Company Request Without Mr. Moul's Adjustments	Capital Structure (A)	Cost Rate (B)	Weighted Cost (A)*(B)
Long-Term Debt	42.65%	5.31%	2.27%
Short-Term Debt	5.14%	2.86%	0.15%
Equity	52.21%	**9.94%**	5.19%
Total	100.00%		7.61%
Rate Base = $1,080,408,495			
		Total x Rate Base = Net Income	**$82,215,564**

In this illustration, the only input that has changed is the equity cost rate, which decreased by 101 basis points. This change equates to a difference in the overall rate of return of 0.53 (53 basis points). These 53 overall basis points (101 basis points on equity) equate to a $5,729,688 ($87,945,252 - $82,215,564) difference in net income.

It is important to note that a change in any of the inputs can change the overall rate of return and therefore the revenue requirement. For instance, a change in capital structure percentages can also affect the overall rate of return.

Also, the dollar amount of the change depends on the determination of the rate base. The larger the rate base, the larger the impact one basis point will have on the revenue requirement.

MISCELLANEOUS

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARDS TO THE RETURN ON EQUITY?

A. Yes. Mr. Moul mentions a 2008 Gas Study, stating that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. He further claims that returns below 10% would trigger broad disenchantment with Local Distribution Companies (LDC).[64]

Q. WHAT COMMENTS DO YOU HAVE REGARDING THIS 2008 GAS STUDY?

A. First, this study includes stale data as it came out in 2008, which is prior to the Great Recession.[65] The Great Recession has had a significant impact on the capital markets and the returns investors are willing to accept.

Second, with new developments in the regulation of utilities, a lower return is necessary due to the lower risk of the Company through the use of DSIC-type

[64] Columbia Statement No. 8, page 6, lines 10-15.
[65] Navigant Consulting (2008) "Regulatory Policy of Return on Equity, Review and Analysis of the Natural Gas Utility Sector," written for the American Gas Foundation.

mechanisms, a FPFTY where cost recovery of future projects are allowable, and other alternative rate making designs. The study also indicates that when utilities operate in a regulatory environment with mutual trust and collaborative development of comprehensive service and rate structures by the LDC and the regulator, this offsets many of the concerns that low allowed returns indicate an unfavorable regulatory environment.

This study also found that although the returns are lower, little impact of this has been seen and public markets for capital have still been accessible for LDCs.

This study's main focus is on the infrastructure of the utilities and the view that low returns will hurt the ability to attract capital to fund the infrastructure improvements. This report also discusses how revenue decoupling can provide revenue stabilization. When revenues are stable there is less risk. Since this report, risk reducers have been introduced such as DSIC and DSIC-type mechanisms, the FPFTY, and other alternative rate designs. It is logical to conclude that lower returns are attributable to these risk reducing mechanisms.

Mr. Moul's claim that a return lower than 10% would trigger broad disenchantment with LDC investment is not supported in the current market, and therefore should be disregarded. Additionally, the Moody's article mentioned early states that it expects that "regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE)."[66]

FULLY PROJECTED FUTURE TEST YEAR

Q. HAS I&E RECOMMENDED ANY CHANGES TO THE LEVEL OF RATE RELIEF GRANTED AS A RESULT OF THE ADVANTAGES OF THE FPFTY?

A. No. I&E witnesses Christopher Keller and Jeremy Hubert identify the effects the FPFTY has on operating and maintenance expenses and rate base but make no adjustments to account for any of the advantages the FPFTY provides. Despite the projected plant additions at December 31, 2016 that Mr. Hubert identifies and the other projected expenses included in the FPFTY that Mr. Keller identifies, I&E asserts that the appropriate place to consider the impact and benefits of the FPFTY is in the assessment of the Company's rate of return.

Q. HAVE YOU RECOMMENDED A PARTICULAR BASIS POINT ADJUSTMENT TO ACCOUNT FOR THE BENEFITS OF THE FPFTY?

A. No. A particular basis point adjustment would be arbitrary as there is no way to determine a specific value the FPFTY has to an investor.

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[66] *Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles*, Moody's Investor Service, Infrastructure and Project Finance, March 10, 2015.

Q. HAVE INVESTOR RESOURCES RECOGNIZED THE IMPACT OF THE FPFTY?

A. Yes. Both debt investors and equity investor evaluators have recognized the benefits of the FPFTY. As previously discussed, the combination of both a FPFTY and a DSIC mechanism is seen as a positive by the credit rating agencies and investors because there will be a more timely collection of investments. Further, a Regulatory Research Associates report published by SNL Energy indicates an expectation that the Commission may impose an adjustment to account for the perceived change in risk due to more a favorable regulatory framework.[67]

OVERALL RATE OF RETURN

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

A. The Company's proposed overall rate of return is 8.14% (Columbia Exhibit 400, page 1 of 28).

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[67] Federico, Lillian. "Regulatory Focus, Final Report, Pennsylvania, Peoples TWP LLC." SNL Energy. Regulatory Research Associates, December 24, 2013. Web. June, 6, 2014.

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

A. I&E Exhibit No. 1, Schedule No. 1, page 1 of 2, shows the calculation of an appropriate overall rate of return for Columbia Gas of Pennsylvania, Inc. to be 7.18%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

RACHEL A. MAURER
PROFESSIONAL EXPERIENCE AND EDUCATION

EMPLOYMENT:

Fixed Utility Financial Analyst 2011 – Present	PA Public Utility Commission Bureau of Investigation & Enforcement
Tax Technician 2008 – 2011	PA Department of Labor and Industry Unemployment Compensation Tax Services
Accounts Payable Representative 2007 – 2008	Select Medical Corporation

EDUCATION/CERTIFICATION:

Lebanon Valley College, B.S. Accounting – 2007

Society of Utility and Regulatory and Financial Analysts
Certified Rate of Return Analyst (CRRA) – May 2015

Advanced Regulatory Studies Program
Michigan State University – 2013

National Association of Regulatory Utility Commissioners Utility Rate School Michigan State University – 2012

TESTIMONY SUBMITTED:

Docket No. R-2015-2462723 – United Water Pennsylvania Inc.
Docket No. R-2014-2428745 – Metropolitan Edison Company
Docket No. R-2014-2428744 – Pennsylvania Power Company
Docket No. R-2014-2428743 – Pennsylvania Electric Company
Docket No. R-2014-2428742 – West Penn Power Company
Docket No. R-2014-2438304 – Borough of Hanover – Hanover Municipal Water Works
Docket No. R-2014-2406274 – Columbia Gas of PA
Docket No. R-2014-2370455 – Penn Estates Utilities, Inc.
Docket No. R-2013-2390244 – City of Bethlehem
Docket No. R-2012-2360798 – Columbia Water Company
Docket No. R-2013-2355886 – Peoples TWP
Docket No. R-2013-2351073 – Columbia Gas of PA 1307(f)
Docket No. R-2013-2341534 – National Fuel Gas Distribution Corp. 1307(f)
Docket No. R-2012-2336379 – York Water Company
Docket No. R-2012-2321748 – Columbia Gas of PA

I&E Exhibit No. 1
Witness: Rachel Maurer

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Exhibit to Accompany

the

Direct Testimony

of

Rachel Maurer

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long term Debt	42.65%	5.31%	2.27%
Short term Debt	5.14%	1.95%	0.10%
Common Equity	52.21%	9.24%	4.82%
Total	100.00%		7.19%

Summary of Cost of Capital

Type of Capital	2014 Ratio	2013 Ratio	2012 Ratio	2011 Ratio	2010 Ratio
Atmos Energy					
Long term Debt	42.80%	45.44%	40.04%	47.26%	43.99%
Short term Debt	3.43%	6.81%	11.68%	4.42%	3.07%
Common Equity	53.78%	47.75%	48.28%	48.32%	52.95%
	100.00%	100.00%	100.00%	100.00%	100.00%
AGL Resources					
Long term Debt	42.07%	44.59%	40.99%	43.42%	39.66%
Short term Debt	13.73%	13.69%	16.96%	16.13%	17.35%
Common Equity	44.20%	41.72%	42.05%	40.45%	42.98%
	100.00%	100.00%	100.00%	100.00%	100.00%
Laclede Group					
Long term Debt	50.76%	46.25%	44.72%	44.40%	36.88%
Short term Debt	7.87%	3.75%	5.28%	5.60%	13.12%
Common Equity	41.37%	50.00%	50.00%	50.00%	50.00%
	100.00%	100.00%	100.00%	100.00%	100.00%
Northwest Natural Gas					
Long term Debt	42.73%	37.25%	36.69%	32.09%	29.29%
Short term Debt	11.94%	18.80%	19.96%	23.08%	21.60%
Common Equity	45.32%	43.94%	43.35%	44.83%	49.11%
	100.00%	100.00%	100.00%	100.00%	100.00%
Piedmont Natural Gas					
Long term Debt	28.55%	24.13%	27.97%	32.10%	32.10%
Short term Debt	19.06%	17.18%	11.76%	2.15%	5.44%
Common Equity	52.39%	58.69%	60.27%	65.75%	62.46%
	100.00%	100.00%	100.00%	100.00%	100.00%
South Jersey Industries					
Long term Debt	42.73%	37.25%	36.69%	32.09%	29.29%
Short term Debt	11.94%	18.80%	19.96%	23.08%	21.60%
Common Equity	45.32%	43.94%	43.35%	44.83%	49.11%
	100.00%	100.00%	100.00%	100.00%	100.00%
Southwest Gas					
Long term Debt	52.60%	49.41%	49.19%	43.16%	49.07%
Short term Debt	0.16%	0.00%	0.00%	0.00%	0.00%
Common Equity	47.24%	50.59%	50.81%	56.84%	50.93%
	100.00%	100.00%	100.00%	100.00%	100.00%
WGL Holdings Inc					
Long term Debt	28.55%	24.13%	27.97%	32.10%	32.10%
Short term Debt	19.06%	17.18%	11.76%	2.15%	5.44%
Common Equity	52.39%	58.69%	60.27%	65.75%	62.46%
	100.00%	100.00%	100.00%	100.00%	100.00%

5 Year Average	
Long term Debt	38.56%
Short term Debt	11.13%
Common Equity	50.31%
	100.00%

Source: Compustat

Long term Debt	41.35%	38.56%	38.03%	38.33%	36.55%
Short term Debt	10.90%	12.03%	12.17%	9.58%	10.95%
Common Equity	47.75%	49.42%	49.80%	52.09%	52.50%

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RR

Question No. I&E-RR-001:

Reference Exhibit No. 400, page 13 of 28. Provide all supporting documentation for the interest rates associated with all long-term debt issuances that have not yet been issued.

Response:

Please see Attachments A and B to this response. I&E-RR-001 Attachment A relates to the actual issue of new CPA debt that took place on March 24, 2015. The actual interest rate on this issue was 4.15% as compared to the estimated rate of 4.16% reflected on pages 2 and 3 of Schedule 6 of Exhibit No. 400. I&E-RR-001 Attachment B provides the basis for the forecast interest rates on long-term debt to be issued in September 2015 and March 2016.

PROMISSORY NOTE

$60,000,000

Issue Date: March 24, 2015
Due Date: March 24, 2045

FOR VALUE RECEIVED, the undersigned, Columbia Gas of Pennsylvania, Inc., a Pennsylvania corporation ("Borrower"), hereby unconditionally promises to pay to NiSource Finance Corp., an Indiana corporation ("Lender"), at such place as Lender may from time to time designate in writing, in lawful money of the United States of America, the principal sum of Sixty Million Dollars ($60,000,000) together with interest on the principal balance hereof from time to time outstanding at the rate of 4.15% per annum from the date such principal is advanced until payment in full thereof. The principal indebtedness evidenced hereby shall be payable on March 24, 2045. Borrower may prepay the principal amount hereof in whole or in part, without premium or penalty, at any time after the first anniversary of the date hereof. Any payment on this Note shall be applied first to accrued but unpaid interest until paid in full and second to the unpaid principal amount hereof.

Interest shall be payable semi-annually in arrears on the first business day of June and December (commencing on June 1, 2015) and on the date on which the principal balance hereof is paid in full. Interest shall be calculated on the basis of a 365 day year for the actual number of days elapsed. Notwithstanding the foregoing, in no contingency or event whatsoever shall interest charged hereunder, however such interest may be characterized or computed, exceed the highest rate permissible under any law which a court of competent jurisdiction shall, in a final determination, deem applicable hereto. In the event that such a court determines that Lender has received interest hereunder in excess of the highest rate applicable hereto, Lender shall promptly refund such excess interest to Borrower.

Borrower shall be in default hereunder if: (a) any amount payable to Lender under this Note is not paid within five (5) business days of the date it is due, (b) Borrower shall make any assignment for the benefit of creditors, or (c) there shall be commenced any bankruptcy or insolvency proceedings by or against Borrower. Upon and after the occurrence of a default hereunder, this Note may, at the option of Lender, and without demand, notice or legal process of any kind, be declared, and thereupon immediately shall become, due and payable in full.

Presentment, protest and notice of nonpayment and protest are hereby waived by Borrower.

This Note has been delivered at and shall be deemed to have been made at Merrillville, Indiana, and shall be interpreted, and the rights and liabilities of the parties hereto determined, in accordance with the laws of the State of Indiana without giving effect to conflict of laws rules or principles. Whenever possible each provision of this Note shall be interpreted in such manner as to be effective and valid under applicable law, but if any provisions of this Note shall be prohibited by or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Note. Whenever in this Note reference is made to Lender or Borrower, such reference shall be deemed to include their respective representatives, successors and assigns. Notwithstanding anything herein to the contrary, Borrower may not assign or otherwise transfer any of its rights or obligations under this Note without the prior written consent of Lender.

IN WITNESS WHEREOF, the undersigned has executed this Note on the issue date set forth above.

Columbia Gas of Pennsylvania, Inc.

By: Mark R Kempic
Mark R. Kempic, President

Columbia of Pennsylvania – March 2015

30-Year Intercompany Note Issuance

30-Year Treasury Bond Yield at March 24, 2015 equals 2.46%. Source: Federal Reserve Board Statistical Release, Selected Interest Rates (Daily)-H.15, dated March 26, 2015.

30-Year Corporate Credit Spread for BBB/Baa2 Rated Utilities at March 24, 2015 equals 1.69%. Source: Reuters Corporate Spreads for Utilities, dated March 26, 2015.

Total Intercompany Note Rate = 2.46% + 1.69% = 4.15%.

I&E-RR-001
Attachment A
Page 3 of 7

I&E Exhibit No. 1
Schedule 3
Page 4 of 21

Selected Interest Rates (Daily) - H.15

Daily Update

Release Date: March 25, 2015

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site. If Monday is a holiday, the weekly release will be posted on Tuesday after the holiday and the daily update will not be posted on that Tuesday.

March 25, 2015
Selected Interest Rates
Yields in percent per annum

Instruments	2015 Mar 23	2015 Mar 24
Federal funds (effective) 1 2 3	0.12	0.11
Commercial Paper 3 4 5 6		
Nonfinancial		
1-month	0.09	0.08
2-month	0.10	0.07
3-month	n.a.	0.09
Financial		
1-month	0.08	0.09
2-month	0.12	0.10
3-month	0.15	0.14
Eurodollar deposits (London) 3 7		
1-month	0.19	0.19
3-month	0.30	0.30
6-month	0.43	0.43
Bank prime loan 2 3 8	3.25	3.25
Discount window primary credit 2 9	0.75	0.75
U.S. government securities		
Treasury bills (secondary market) 3 4		
4-week	0.02	0.03
3-month	0.03	0.02
6-month	0.11	0.11
1-year	0.22	0.22
Treasury constant maturities		
Nominal 10		
1-month	0.02	0.03
3-month	0.03	0.02
6-month	0.11	0.11
1-year	0.24	0.24
2-year	0.60	0.58
3-year	0.93	0.91
5-year	1.41	1.37
7-year	1.71	1.68

Instruments	2015 Mar 23	2015 Mar 24
10-year	1.92	1.88
20-year	2.29	2.24
30-year	2.51	2.46
Inflation indexed 11		
5-year	-0.07	-0.16
7-year	0.10	0.03
10-year	0.17	0.11
20-year	0.44	0.38
30-year	0.62	0.55
Inflation-indexed long-term average 12	0.48	0.41
Interest rate swaps 13		
1-year	0.49	0.49
2-year	0.85	0.84
3-year	1.16	1.15
4-year	1.39	1.38
5-year	1.56	1.55
7-year	1.81	1.79
10-year	2.02	2.00
30-year	2.35	2.33
Corporate bonds		
Moody's seasoned		
Aaa 14	3.54	3.50
Baa	4.46	4.41
State & local bonds 15		
Conventional mortgages 16		

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.

10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.

11. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/.

12. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.

13. International Swaps and Derivatives Association (ISDA®) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. Eastern time by Thomson Reuters and published on Thomson Reuters Page ISDAFIX®1. ISDAFIX is a registered service mark of ISDA®. Source: Thomson Reuters.

14. Moody's Aaa rates through December 6, 2001, are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only. Data obtained from Bloomberg Finance L.P.

15. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations. Data obtained from Bloomberg Finance L.P.

16. Contract interest rates on commitments for 30-year fixed-rate first mortgages. Source: Primary Mortgage Market Survey® data provided by Freddie Mac.

Note: Weekly and monthly figures on this release, as well as annual figures available on the Board's historical H.15 web site (see below), are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886).

Description of the Treasury Nominal and Inflation-Indexed Constant Maturity Series

Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3, and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10, 20, and 30 years.

Last update: March 25, 2015

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Quotes & Data

From the Desk of Vincent Rea
Thursday, March 26 2015 09:19 AM

Bond$$ Available Balance $55.00

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Estimated Cost: $35.00
Actual Cost: $35.00

REUTERS CORPORATE BOND SPREAD TABLES

Reuters Corporate Spreads for Utilities
03/24/2015

Rating	1 yr	2 yr	3 yr	5 yr	7 yr	10 yr	30 yr
Aaa/AAA	10	14	19	26	37	51	70
Aa1/AA+	16	22	28	36	46	59	79
Aa2/AA	23	31	37	46	55	67	88
Aa3/AA-	29	39	47	56	64	75	96
A1/A+	36	48	56	66	74	83	105
A2/A	42	56	65	76	83	91	114
A3/A-	46	62	72	84	92	100	127
Baa1/BBB+	62	82	94	109	119	129	161
Baa2/BBB	89	106	115	127	135	143	169
Baa3/BBB-	137	169	187	211	226	243	293
Ba1/BB+	230	244	258	274	286	299	314
Ba2/BB	260	275	291	308	321	335	351

I&E Exhibit No. 1
Schedule 3
Page 7 of 21

Ba3/BB-	290	306	323	341	355	371	388
B1/B+	325	342	360	379	395	412	430
B2/B	355	373	392	413	430	448	467
B3/B-	384	404	424	446	464	483	504
Caa/CCC+	419	440	461	484	503	524	546
US Treasury Yield	0.24	0.58	0.91	1.37	1.68	1.88	2.46

Spread values represent basis points (bps) over a US Treasury security of the same maturity, or the closest matching maturity.

Methodology:
Reuters Pricing Service (RPS) has eight experienced evaluators responsible for pricing approximately 20,000 investment grade corporate bonds. Corporate bonds are segregated into four industry sectors; industrial, financial, transports and utilities. RPS prices corporate bonds at a spread above an underlying treasury issue. The evaluators obtain the spreads from brokers and traders at various firms. A generic spread for each sector is created using input from street contacts and the evaluator's expertise. A matrix is then developed based on sector, rating, and maturity.

US Treasury Yields for this date are available in the BondsOnline Chart Center

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I&E Exhibit No. 1
Schedule 3
Page 8 of 21

NiSource

Corporate Treasury Department

To: Files
From: Treasury Operations
Date: January 22, 2015
Re: CPA Forecasted Rates

Objective

Provided below are forecasted rates for 30-year notes anticipated to be issued in 2014 and 2015, as well as forecasted ST borrowing rates.

Results

30-year Forecasted Rates

Issuance	US Treasury Rate (1)	NiSource BBB Spread (2)	All-in Coupon Rate
01/21/2015 30 Year Rate - HP	2.440% B	1.70% A	4.14%
03/01/2015 30 Year Rate - FP	2.486% C	1.68%	4.16%
09/01/2015 30 Year Rate - FP	2.572% D	1.63%	4.21%
03/01/2016 30 Year Rate - FP	2.593% E	1.62%	4.22%

HP = Historical Price

FP = Forward Price

1) U.S. Treasury forward rates were obtained from Bloomberg's forward curve matrix on 1/22/2015. The historical price was obtained from Bloomberg's Historical Price function for the date 1/21/15.

2) CPA/NiSource's credit spread was obtained from Reuter's Corporate Bond Spread Table (Utilities) for a Baa2/BBB credit rating as of 1/21/2015. An assumption was made that this credit spread would change inversely to the change in the U.S. Treasury rate by approximately one-half.

Short-term Borrowings Forecasted Rates

Period	1-mo. LIBOR Rate (1)	NiSource Revolver Spread (2)	All-in Rate
01/21/2015 - HP	0.167% F	1.275%	1.44%
03/31/2015 - FP	0.256% G	1.275%	1.53%
06/30/2015 - FP	0.414% H	1.275%	1.69%
09/30/2015 - FP	0.578% I	1.275%	1.85%
11/30/2015 - FP	0.661% K	1.275%	1.94%
12/31/2015 - FP	0.806% J	1.275%	2.08%
12/31/2016 - FP	1.583% L	1.275%	2.86%

1) 1 month forward LIBOR rates were obtained from Bloomberg's forward curve matrix on 1/8/2015 (1/22/15 for the 11/30/15 and 12/31/16 rates). The historical price was obtained from Bloomberg's Historical Price function for the date 1/21/15.
2) The revolver spread is reflective of a Baa2/BBB rating.

BondsOnline
Quotes & Data

From the Desk of Vincent Rea
Thursday, January 22 2015 12:31 PM

Bond$$ Available Balance $25.00

REQUEST DATA

Estimated Cost: $35.00
Actual Cost: $35.00

REUTERS CORPORATE BOND SPREAD TABLES

Reuters Corporate Spreads for Utilities
01/21/2015

Rating	1 yr	2 yr	3 yr	5 yr	7 yr	10 yr	30 yr
Aaa/AAA	10	14	19	26	37	51	70
Aa1/AA+	16	22	28	36	46	59	79
Aa2/AA	22	31	37	46	55	67	88
Aa3/AA-	29	40	47	56	64	75	97
A1/A+	35	48	56	66	74	83	106
A2/A	41	57	65	76	83	91	115
A3/A-	42	58	68	80	88	97	124
Baa1/BBB+	58	78	91	106	116	127	159
Baa2/BBB	78	97	108	122	131	140	170
Baa3/BBB-	128	160	178	201	217	233	283
Ba1/BB+	223	237	251	267	279	292	307
Ba2/BB	253	268	284	301	314	328	344
Ba3/BB-	283	299	316	334	348	364	381
B1/B+	318	335	353	372	388	405	423
B2/B	348	366	385	406	423	441	460
B3/B-	377	397	417	439	457	476	497
Caa/CCC+	412	433	454	477	496	517	539
US Treasury Yield	0.17	0.53	0.87	1.35	1.66	1.87	2.44

Spread values represent basis points (bps) over a US Treasury security of the same maturity, or the closest matching maturity.

Methodology:
Reuters Pricing Service (RPS) has eight experienced evaluators responsible for pricing approximately 20,000 investment grade corporate bonds. Corporate bonds are segregated into four industry sectors; industrial, financial, transports and utilities. RPS prices corporate bonds at a spread above an underlying treasury issue. The evaluators obtain the spreads from brokers and traders at various firms. A generic spread for each sector is created using input from street contacts and the evaluator's expertise. A matrix is then developed based on sector, rating, and maturity.

US Treasury Yields for this date are available in the BondsOnline Chart Center

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I15T30Y 2.46 As Of 16:10

JS Treasury Yield Curve Rate T Note Constant Maturity 30 Year

[redacted] 96) Export to Excel Page 1/6 Historical Price

Treasury Yield Curve Rate T Note Constant Maturity 30 Year

nge [redacted] - [redacted] Period [redacted]
rket [redacted] [redacted] Currency [redacted]
w [redacted]

High	3.75	on	01/22/14
Low	2.39	on	01/20/15
Average	3.27		3.27
Net Chg	-1.30		-34.76%

Date	Last Price	Mid Line		Date	Last Price	Mid Line		Date	Last Price	Mid Line
01/23/15			F	01/02/15	2.69	2.69	F	12/12/14	2.75	2.75
01/22/15			T	01/01/15			T	12/11/14	2.84	2.84
01/21/15	2.44	B 2.44	W	12/31/14	2.75	2.75	W	12/10/14	2.83	2.83
01/20/15 L	2.39	2.39	T	12/30/14	2.76	2.76	T	12/09/14	2.87	2.87
01/19/15			M	12/29/14	2.78	2.78	M	12/08/14	2.90	2.90
01/16/15	2.44	2.44	F	12/26/14	2.81	2.81	F	12/05/14	2.97	2.97
01/15/15	2.40	2.40	T	12/25/14			T	12/04/14	2.94	2.94
01/14/15	2.47	2.47	W	12/24/14	2.83	2.83	W	12/03/14	2.99	2.99
01/13/15	2.49	2.49	T	12/23/14	2.85	2.85	T	12/02/14	3.00	3.00
01/12/15	2.49	2.49	M	12/22/14	2.75	2.75	M	12/01/14	2.95	2.95
01/09/15	2.55	2.55	F	12/19/14	2.77	2.77	F	11/28/14	2.89	2.89
01/08/15	2.59	2.59	T	12/18/14	2.82	2.82	T	11/27/14		
01/07/15	2.52	2.52	W	12/17/14	2.74	2.74	W	11/26/14	2.95	2.95
01/06/15	2.52	2.52	T	12/16/14	2.69	2.69	T	11/25/14	2.97	2.97
01/05/15	2.60	2.60	M	12/15/14	2.74	2.74	M	11/24/14	3.01	3.01

<HELP> for explanation.

[illegible] 5) Export 6) Graph **Forward Curve Matrix**

JS Treasury Actives Curve [illegible] Yield [illegible] « Curve List

Two Curve Spreads

Select a curve under "Curve List" for two... [illegible] Yield [illegible]

ward Curve Date [illegible] OIS Discounting

t Coupon Zero

		Forwards											
ors	Coupon	3/1/2015	1Mo	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.0152	0.0178	0.0175	0.0949	0.1768	0.5596	1.3141	1.6529	2.1494	2.1923	2.2005	2.5368	2.595
	0.0177	0.0510	0.0451	0.1317	0.2049	0.6188	1.3755	1.6925	2.1895	2.2180	2.2052	2.5419	2.595
	0.0735	0.1071	0.1027	0.1679	0.2516	0.7107	1.4708	1.7539	2.2516	2.2579	2.2125	2.5499	2.595
	0.1599	0.2230	0.2093	0.3119	0.4807	0.8931	1.6574	1.8771	2.3736	2.3392	2.2286	2.5676	2.595
	0.5214	0.6129	0.5815	0.6944	0.8747	1.2725	1.7662	2.1226	2.3566	2.4997	2.2610	2.6030	2.595
	0.8950	0.9607	0.9451	1.0370	1.1785	1.4706	1.9644	2.1931	2.4566	2.4163	2.2934	2.6386	2.595
	1.3728	1.4371	1.4131	1.4854	1.5953	1.8142	2.1712	2.2946	2.4017	2.4322	2.3586	2.7105	2.595
	1.6781	1.7277	1.7076	1.7595	1.8372	1.9873	2.2097	2.3384	2.3962	2.3862	2.4242	2.7835	2.595
r	1.8734	1.9175	1.8952	1.9330	1.9893	2.0965	2.2491	2.3260	2.3862	2.3976	2.5234	2.8943	2.595
r	2.4461	2.4845 C	2.4580	2.4766	2.5045	2.5579	2.6377	2.6839	2.7211	2.7354	2.7984	2.8924	2.595

y values are extrapolated

<HELP> for explanation.
reen Printed

Treasury Actives Curve | 5) Export | 6) Graph | Forward Curve Matrix

US Treasury Actives Curve | Yield | « Curve List

Two Curve Spreads

Select a curve under "Curve List" for two... | Yield

ward Curve Date | OIS Discounting

t | Coupon | Zero

			Forwards									
ors	Coupon	9/1/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
o	0.0076	0.2159	0.0895	0.1797	0.5689	1.2753	1.6662	2.1808	2.2162	2.2422	2.5971	2.6605
o	0.0228	0.2464	0.1229	0.2093	0.6293	1.3331	1.7072	2.2223	2.2425	2.2471	2.6025	2.6605
o	0.0735	0.3339	0.1656	0.2584	0.7229	1.4226	1.7709	2.2867	2.2834	2.2549	2.6110	2.6604
	0.1599	0.5640	0.3157	0.4902	0.9082	1.5985	1.8985	2.4131	2.3667	2.2719	2.6296	2.6604
	0.5093	0.9451	0.6973	0.8720	1.2509	1.7472	2.1529	2.3902	2.5314	2.3059	2.6671	2.6604
	0.8790	1.2283	1.0243	1.1681	1.4631	1.9645	2.2225	2.4910	2.4539	2.3401	2.7048	2.6604
	1.3614	1.6462	1.4900	1.6016	1.8226	2.1834	2.3291	2.4440	2.4804	2.4089	2.7807	2.6604
	1.6711	1.8814	1.7720	1.8517	2.0049	2.2333	2.3811	2.4424	2.4335	2.4781	2.8576	2.6604
r	1.8794	2.0386	1.9583	2.0159	2.1251	2.2809	2.3698	2.4336	2.4468	2.5828	2.9746	2.6604
r	2.4759	2.5716	2.5305	2.5594	2.6143	2.6967	2.7491	2.7888	2.8046	2.8737	2.9750	2.6604

b

y values are extrapolated

<HELP> for explanation.
reen Printed

[illegible] 5) Export 6) Graph Forward Curve Matrix

JS Treasury Actives Curve [illegible] Yield Conventional « Curve List

wo Curve Spreads

Select a curve under "Curve List" for two... [illegible] Yield Conventional

ward Curve Date [illegible] OIS Discounting

t Coupon Zero

			Forwards										
ors	Coupon	3/1/2016	1Mo	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.0152	0.6574	0.0175	0.0949	0.1768	0.5596	1.3141	1.6529	2.1494	2.1923	2.2005	2.5368	2.595
	0.0177	0.7216	0.0451	0.1317	0.2049	0.6188	1.3755	1.6925	2.1895	2.2180	2.2052	2.5419	2.595
	0.0735	0.8169	0.1027	0.1679	0.2516	0.7107	1.4708	1.7539	2.2516	2.2579	2.2125	2.5499	2.595
	0.1599	1.0039	0.2093	0.3119	0.4807	0.8931	1.6574	1.8771	2.3736	2.3392	2.2286	2.5676	2.595
	0.5194	1.3338	0.5815	0.6944	0.8747	1.2725	1.7662	2.1226	2.3566	2.4997	2.2610	2.6030	2.595
	0.8950	1.5370	0.9451	1.0370	1.1785	1.4706	1.9644	2.1931	2.4566	2.4163	2.2934	2.6386	2.595
	1.3712	1.8708	1.4131	1.4854	1.5953	1.8142	2.1712	2.2946	2.4017	2.4322	2.3586	2.7105	2.595
	1.6781	2.0309	1.7076	1.7595	1.8372	1.9873	2.2097	2.3384	2.3962	2.3862	2.4242	2.7835	2.595
r	1.8725	2.1351	1.8952	1.9330	1.9893	2.0965	2.2491	2.3260	2.3862	2.3976	2.5234	2.8943	2.595
r	2.4461	2.5930 E	2.4580	2.4766	2.5045	2.5579	2.6377	2.6839	2.7211	2.7354	2.7984	2.8924	2.595

y values are extrapolated

S0001M 0.16675 -.00175 0.00000 /0.00000
t 1/21 d Op 0.16675 Hi 0.16675 Lo 0.16675 Prev 0.16850

0001M Index 96) Export to Excel Page 1/5 Historical Price

LIBOR USD 1 Month

nge	01/24/2014 - [illegible]	Period	Daily	High .17125 on 12/31/14
rket	Ask Price	Currency	[illegible]	Low .14775 on 05/20/14
				Average .15541
w	Dense (HP)			Net Chg .00875 5.54%

Date	Ask Price		Date		Ask Price		Date	Ask Price
01/23/15		F	01/02/15		.16750	F	12/12/14	.16100
01/22/15	F	T	01/01/15			T	12/11/14	.16080
01/21/15	.16675	W	12/31/14	H	.17125	W	12/10/14	.16080
01/20/15	.16850	T	12/30/14		.16950	T	12/09/14	.15850
01/19/15	.16875	M	12/29/14		.16925	M	12/08/14	.16170
01/16/15	.16800	F	12/26/14			F	12/05/14	.15800
01/15/15	.16800	T	12/25/14			T	12/04/14	.15720
01/14/15	.16825	W	12/24/14		.16875	W	12/03/14	.15700
01/13/15	.16650	T	12/23/14		.16950	T	12/02/14	.15825
01/12/15	.16650	M	12/22/14		.16700	M	12/01/14	.15775
01/09/15	.16675	F	12/19/14		.16425	F	11/28/14	.15400
01/08/15	.16625	T	12/18/14		.16545	T	11/27/14	.15500
01/07/15	.16650	W	12/17/14		.16410	W	11/26/14	.15575
01/06/15	.16775	T	12/16/14		.16200	T	11/25/14	.15625
01/05/15	.16800	M	12/15/14		.16200	M	11/24/14	.15350

Interest Rate Forecasts
Projections for LIBOR

<HELP> for explanation.
FWCV<Go> for Forward Curve Analysis

5) Export 6) Graph Forward Curve Matrix

US Dollar Swaps (30/360, S/A) Yield « Curve List

Select a curve under "Curve List" for t... Yield
Forward Curve Date OIS Discounting
Coupon Zero

		Forwards										
ors	Coupon	3/31/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.1718	G 0.2564	0.1816	0.3536	0.7802	1.6531	2.1302	2.2348	2.4128	2.8477	2.8827	2.7708
	0.2521	0.2939	0.3125	0.4756	0.9177	1.7172	2.1195	2.2489	2.4320	2.7696	2.7985	2.6890
	0.2820	0.3717	0.3942	0.5824	1.0361	1.8005	2.1173	2.3118	2.4726	2.8058	2.8273	2.7115
	0.4295	0.5714	0.5993	0.8099	1.2577	1.9356	2.2101	2.4177	2.5520	2.8507	2.8574	2.7306
	0.8383	0.9998	1.0271	1.2229	1.5936	2.0717	2.3122	2.4842	2.5998	2.8643	2.8695	2.7236
	1.1898	1.3351	1.3583	1.5084	1.7957	2.1840	2.3900	2.5377	2.6349	2.8580	2.8827	2.7166
	1.4466	1.5525	1.5740	1.7030	1.9456	2.2725	2.4522	2.5789	2.6648	2.8689	2.8913	2.7111
	1.6331	1.7283	1.7441	1.8546	2.0611	2.3441	2.5007	2.6130	2.6904	2.8822	2.8985	2.7034
	1.9867	2.0541	2.0655	2.1437	2.2874	2.4883	2.6064	2.6931	2.7489	2.8823	2.8670	2.6806
	2.0619	2.1250	2.1373	2.2085	2.3388	2.5243	2.6334	2.7082	2.7643	2.8859	2.8606	2.6726
	2.1297	2.1869	2.1968	2.2629	2.3840	2.5555	2.6520	2.7254	2.7796	2.8897	2.8549	2.6646
	2.3485	2.3883	2.3961	2.4432	2.5287	2.6506	2.7230	2.7760	2.8138	2.8654	2.8255	2.5930
	2.4590	2.4900	2.4966	2.5338	2.6010	2.6959	2.7497	2.7873	2.8119	2.8429	2.8010	2.5380
	2.5379	2.5613	2.5661	2.5937	2.6133	2.7125	2.7506	2.7763	2.7918	2.7988	2.7325	2.2220

y values are extrapolated

<HELP> for explanation.
Run FWCV<Go> for Forward Curve Analysis

US Dollar Swaps (30/360, S/A) | 5) Export | 6) Graph | Forward Curve Matrix

US Dollar Swaps (30/360, S/A) Mid Yield Conventional « Curve List

Select a curve under "Curve List" for t... Yield Conventional

Forward Curve Date | OIS Discounting

Spot | Coupon | Zero

		Forwards										
Tenors	Coupon	6/30/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
1Mo	0.1718	H 0.4144	0.1816	0.3536	0.7802	1.6531	2.1302	2.2348	2.4128	2.8477	2.3827	2.7708
3Mo	0.2521	0.4491	0.3125	0.4756	0.9177	1.7172	2.1195	2.2489	2.4320	2.7696	2.7985	2.6890
6Mo	0.2820	0.5528	0.3942	0.5824	1.0361	1.8005	2.1173	2.3118	2.4726	2.8058	2.3273	2.7115
1Yr	0.4295	0.7790	0.5993	0.8099	1.2577	1.9356	2.2101	2.4177	2.5520	2.8507	2.3574	2.7306
2Yr	0.8333	1.1955	1.0271	1.2229	1.5936	2.0717	2.3122	2.4842	2.5998	2.8643	2.8695	2.7236
3Yr	1.1890	1.4865	1.3583	1.5084	1.7957	2.1840	2.3900	2.5377	2.6349	2.8580	2.8827	2.7166
4Yr	1.4466	1.6820	1.5740	1.7030	1.9456	2.2725	2.4522	2.5789	2.6648	2.8689	2.8913	2.7111
5Yr	1.6330	1.8376	1.7441	1.8546	2.0611	2.3441	2.5007	2.6130	2.6904	2.8322	2.3985	2.7034
6Yr	1.9865	2.1309	2.0655	2.1437	2.2874	2.4883	2.6064	2.6931	2.7489	2.8323	2.3679	2.6806
9Yr	2.0637	2.1960	2.1373	2.2085	2.3388	2.5243	2.6334	2.7082	2.7643	2.8859	2.8606	2.6725
10Yr	2.1300	2.2516	2.1968	2.2629	2.3840	2.5555	2.6520	2.7254	2.7796	2.6897	2.8549	2.6646
15Yr	2.3497	2.4342	2.3961	2.4432	2.5287	2.6506	2.7230	2.7760	2.8138	2.8654	2.8255	2.5930
20Yr	2.4593	2.5259	2.4966	2.5338	2.6010	2.6959	2.7497	2.7873	2.8119	2.8429	2.8010	2.5380
30Yr	2.5378	2.5874	2.5661	2.5937	2.6433	2.7125	2.7506	2.7763	2.7918	2.7988	2.7325	2.2220

Grey values are extrapolated

<HELP> for explanation.
n FWCV<Go> for Forward Curve Analysis

Dollar Swaps (30/360, S/A) 5) Export 6) Graph Forward Curve Matrix

S Dollar Swaps (30/360, S/A) Yield Conventional « Curve List

elect a curve under "Curve List" for t... Yield Conventional

ward Curve Date 30-Sep-2015 OIS Discounting

t Coupon Zero

						Forwards						
rs	Coupon	9/30/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.1718	0.5782	0.1816	0.3536	0.7802	1.6531	2.1302	2.2348	2.4128	2.8477	2.8827	2.7708
	0.2521	0.6557	0.3125	0.4756	0.9177	1.7172	2.1195	2.2489	2.4320	2.7696	2.7985	2.6890
	0.2820	0.7719	0.3942	0.5824	1.0361	1.8005	2.1173	2.3118	2.4726	2.8058	2.8273	2.7115
	0.4277	1.0052	0.5993	0.8099	1.2577	1.9356	2.2101	2.4177	2.5520	2.8507	2.8574	2.7306
	0.8375	1.3893	1.0271	1.2229	1.5936	2.0717	2.3122	2.4342	2.5998	2.8643	2.8695	2.7236
	1.1901	1.6348	1.3583	1.5084	1.7957	2.1840	2.3900	2.5377	2.6349	2.8580	2.8827	2.7166
	1.4472	1.8112	1.5740	1.7030	1.9456	2.2725	2.4522	2.5789	2.6648	2.8689	2.8913	2.7111
	1.6330	1.9478	1.7441	1.8546	2.0611	2.3441	2.5007	2.6130	2.6904	2.8822	2.8985	2.7034
	1.9867	2.2077	2.0655	2.1437	2.2374	2.4833	2.6064	2.6931	2.7489	2.8823	2.8670	2.6806
	2.0637	2.2667	2.1373	2.2085	2.3388	2.5243	2.6334	2.7082	2.7643	2.8859	2.8606	2.6726
	2.1309	2.3174	2.1968	2.2629	2.3840	2.5555	2.6520	2.7254	2.7796	2.8897	2.8549	2.6646
	2.3486	2.4813	2.3961	2.4432	2.5287	2.6506	2.7230	2.7760	2.8138	2.8654	2.8255	2.5930
	2.4585	2.5632	2.4966	2.5338	2.6010	2.6959	2.7497	2.7873	2.8119	2.8429	2.8010	2.5380
	2.5378	2.6154	2.5661	2.5937	2.6433	2.7125	2.7506	2.7763	2.7918	2.7988	2.7325	2.2220

y values are extrapolated

HELP> for explanation.
FWCV<Go> for Forward Curve Analysis

Dollar Swaps (30/360 S/A) 5) Export 6) Graph Forward Curve Matrix
S Dollar Swaps (30/360, S/A) Mid Yield Conventional « Curve List

elect a curve under "Curve List" for t... Mid Yield Conventional
vard Curve Date 31-Dec-2015 OIS Discounting
Coupon Zero

rs	Coupon	12/31/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
					Forwards							
	0.1718	0.8057	0.1816	0.3536	0.7802	1.6531	2.1302	2.2348	2.4128	2.8477	2.8827	2.7708
	0.2521	0.8867	0.3125	0.4756	0.9177	1.7172	2.1195	2.2489	2.4320	2.7696	2.7985	2.6890
	0.2820	1.0063	0.3942	0.5824	1.0361	1.8005	2.1173	2.3118	2.4726	2.8058	2.8273	2.7115
	0.4290	1.2254	0.5993	0.8099	1.2577	1.9356	2.2101	2.4177	2.5520	2.8597	2.8574	2.7306
	0.8377	1.5682	1.0271	1.2229	1.5936	2.0717	2.3122	2.4842	2.5908	2.8543	2.8695	2.7236
	1.1915	1.7753	1.3583	1.5084	1.7957	2.1840	2.3900	2.5377	2.6349	2.8580	2.8827	2.7166
	1.4467	1.9234	1.5740	1.7030	1.9456	2.2725	2.4522	2.5789	2.6648	2.8689	2.8913	2.7111
	1.6331	2.0469	1.7441	1.8546	2.0611	2.3441	2.5007	2.6130	2.6994	2.8822	2.8985	2.7034
	1.9867	2.2753	2.0655	2.1437	2.2874	2.4883	2.6064	2.6931	2.7489	2.8923	2.8670	2.6806
	2.0637	2.3285	2.1373	2.2085	2.3388	2.5243	2.6334	2.7082	2.7643	2.8859	2.8606	2.6726
	2.1309	2.3747	2.1968	2.2629	2.3840	2.5555	2.6520	2.7254	2.7796	2.8897	2.8549	2.6646
	2.3486	2.5208	2.3961	2.4432	2.5287	2.6506	2.7230	2.7760	2.8138	2.8654	2.8255	2.5930
	2.4535	2.5939	2.4966	2.5338	2.6010	2.6959	2.7497	2.7873	2.8119	2.8429	2.8010	2.5380
	2.5378	2.6376	2.5661	2.5937	2.6433	2.7125	2.7506	2.7763	2.7918	2.7983	2.7325	2.2220

values are extrapolated

<HELP> for explanation.
n FWCV<Go> for Forward Curve Analysis

Dollar Swaps (30/360, S/A) 5) Export 6) Graph Forward Curve Matrix

JS Dollar Swaps (30/360, S/A) Yield « Curve List
'wo Curve Spreads
Select a curve under "Curve List" for two... Yield
ward Curve Date OIS Discounting
t Coupon Zero

			Forwards									
ors	Coupon	11/30/2015	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.1739	0.6610	0.1794	0.3147	0.6860	1.5167	2.0082	2.1059	2.2684	2.5002	2.6494	2.5829
	0.4020	1.0165	0.5503	0.7361	1.1413	1.7958	2.0551	2.2887	2.4061	2.4942	2.6246	2.5456
	0.7705	1.3633	0.9390	1.1189	1.4659	1.9245	2.1702	2.3469	2.4502	2.6574	2.6356	2.5403
	1.0960	1.5786	1.2519	1.3910	1.6593	2.0429	2.2468	2.3953	2.4838	2.6498	2.6477	2.5350
	1.3485	1.7420	1.4583	1.5800	1.8114	2.1304	2.3067	2.4335	2.5119	2.6591	2.6557	2.5311
	1.5213	1.8666	1.6252	1.7293	1.9249	2.2000	2.3536	2.4652	2.5359	2.6711	2.6627	2.5250
	1.8661	2.1042	1.9362	2.0096	2.1453	2.3399	2.4327	2.5305	2.5759	2.6629	2.6360	2.5071
	1.9373	2.1574	2.0053	2.0720	2.1950	2.3552	2.4720	2.5408	2.5872	2.6647	2.6308	2.5007
r	1.9997	2.1905	2.0585	2.1163	2.2216	2.3971	2.4864	2.5539	2.5991	2.6672	2.6263	2.4942
r	2.1957	2.3376	2.2402	2.2832	2.3615	2.4746	2.5403	2.5876	2.6176	2.6433	2.5999	2.4235
r	2.2917	2.4033	2.3261	2.3600	2.4214	2.5094	2.5582	2.5918	2.6110	2.6213	2.5846	2.3716
r	2.3605	2.4421	2.3853	2.4105	2.4558	2.5202	2.5550	2.5785	2.5907	2.5892	2.5280	2.0838

y values are extrapolated

<HELP> for explanation.
n FWCV<Go> for Forward Curve Analysis

Dollar Swaps (30/360, S/A) 5) Export 6) Graph Forward Curve Matrix

JS Dollar Swaps (30/360, S/A) Yield Conventional « Curve List
wo Curve Spreads
elect a curve under "Curve List" for two... Yield Conventional
vard Curve Date OIS Discounting
☒Coupon ☒Zero

			Forwards									
rs	Coupon	12/31/2016	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
	0.1739	L 1.5834	0.1794	0.3147	0.6860	1.5167	2.0082	2.1059	2.2684	2.5002	2.6494	2.5829
	0.4020	1.7590	0.5503	0.7361	1.1413	1.7958	2.0551	2.2887	2.4061	2.4942	2.6246	2.5456
	0.7705	1.8977	0.9390	1.1189	1.4659	1.9245	2.1702	2.3469	2.4502	2.6574	2.6356	2.5403
	1.0960	2.0186	1.2519	1.3910	1.6593	2.0429	2.2468	2.3953	2.4838	2.6498	2.6477	2.5350
	1.3490	2.1097	1.4583	1.5800	1.8114	2.1304	2.3067	2.4335	2.5119	2.6591	2.6557	2.5311
	1.5225	2.1821	1.6252	1.7293	1.9249	2.2000	2.3536	2.4652	2.5359	2.6711	2.6627	2.5250
	1.8650	2.3257	1.9362	2.0096	2.1453	2.3399	2.4327	2.5305	2.5759	2.6629	2.6360	2.5071
	1.9370	2.3447	2.0053	2.0720	2.1950	2.3552	2.4720	2.5408	2.5872	2.6647	2.6308	2.5007
-	1.9992	2.3843	2.0585	2.1163	2.2216	2.3971	2.4864	2.5539	2.5991	2.6672	2.6263	2.4942
-	2.1950	2.4658	2.2402	2.2832	2.3615	2.4746	2.5403	2.5876	2.6176	2.6433	2.5999	2.4235
-	2.2940	2.5023	2.3261	2.3600	2.4214	2.5094	2.5582	2.5918	2.6110	2.6213	2.5846	2.3716
-	2.3610	2.5143	2.3853	2.4105	2.4558	2.5202	2.5550	2.5785	2.5907	2.5892	2.5280	2.0838

/ values are extrapolated

	2014		
	Interest Charges	**Long-term Debt**	**Debt Cost**
Atmos Energy Corp	130.795	2455.986	5.33%
AGL Resources Inc	181.000	3813.000	4.75%
Laclede Group Inc	46.200	1851.000	2.50%
Northwest Natural Gas Co	44.563	621.700	7.17%
Piedmont Natural Gas Company	71.113	1424.430	4.99%
South Jersey Industries Inc	34.160	879.150	3.89%
Southwest Gas	73.297	1657.634	4.42%
WGL Holdings Inc	37.738	679.228	5.56%
	Range:	Low	2.50%
		High	7.17%
		Average	4.82%

Source: Compustat

Columbia Gas of Pennsylvania
Short-Term Debt

		Balance ($000)	Rate %	Weighted Rate	1-month LIBOR	Spread
Dec-12	$	-	1.28%	0.00%	0.2108%	1.07%
Jan-13	$	-	1.19%	0.00%	0.2051%	0.98%
Feb-13	$	-	1.17%	0.00%	0.2013%	0.97%
Mar-13	$	-	1.07%	0.00%	0.2035%	0.87%
Apr-13	$	-	0.96%	0.00%	0.1997%	0.76%
May-13	$	-	0.56%	0.00%	0.1966%	0.36%
Jun-13	$	-	0.67%	0.00%	0.1932%	0.48%
Jul-13	$	-	0.70%	0.00%	0.1911%	0.51%
Aug-13	$	-	0.69%	0.00%	0.1841%	0.51%
Sep-13	$	22,845	0.68%	0.02%	0.1806%	0.50%
Oct-13	$	43,094	0.68%	0.04%	0.1724%	0.51%
Nov-13	$	41,531	0.68%	0.04%	0.1673%	0.51%
Dec-13	$	41,296	0.71%	0.04%	0.1672%	0.54%
Jan-14	$	-	0.71%	0.00%	0.2386%	0.47%
Feb-14	$	-	0.69%	0.00%	0.2352%	0.45%
Mar-14	$	-	0.61%	0.00%	0.2341%	0.38%
Apr-14	$	-	0.59%	0.00%	0.2273%	0.36%
May-14	$	-	0.61%	0.00%	0.2261%	0.38%
Jun-14	$	26,931	0.64%	0.02%	0.2309%	0.41%
Jul-14	$	70,063	0.67%	0.07%	0.2342%	0.44%
Aug-14	$	89,642	0.73%	0.09%	0.2348%	0.50%
Sep-14	$	105,719	0.67%	0.10%	0.2340%	0.44%
Oct-14	$	124,501	0.66%	0.12%	0.2314%	0.43%
Nov-14	$	125,029	0.71%	0.13%	0.2329%	0.48%
	$	690,651				
Average:				0.76%		0.55%
Weighted Average				0.00%		
Low:				0.56%		
High:				1.28%		

Projected 3-Month LIBOR		Average Spread		Projected Short-Term Debt Cost
(1)		(2)		(1) + (2)
1.40%	+	**0.55%**	=	**1.95%**

Source:

Columbia Standard Data Request, Question No. GAS-ROR-16, Attachment A.
http://www.fedprimerate.com/libor/libor_rates_history.htm
Blue Chip Financial Forecasts, March 1, 2015 and December 1, 2015.

I&E Exhibit No. 1
Schedule 6
Page 1 of 2

The New York Times **Business Day**

Market Place; A Study Shakes Confidence In the Volatile-Stock Theory

By ERIC N. BERG
Published: February 18, 1992

One of the most enduring ideas of modern finance is facing its most serious challenge. Two scholars of finance say they have disproved the theory, common among investors, that stocks more volatile than the market as a whole are the best performers.

Eugene F. Fama and Kenneth R. French, business professors at the University of Chicago, traced the performance of thousands of stocks over 50 years but found no link between relative volatility and long-term returns. The many investors who try to beat the market by buying widely swinging issues are misguided, they say.

The importance of "beta," the investment community's term for a stock's volatility relative to the market, has long been under challenge. But it is still closely watched by analysts, and business students are still taught that they can earn higher returns by buying stocks whose swings are wider than the market's.

"The fact is," Professor Fama said in a recent telephone interview, "beta as the sole variable explaining returns on stocks is dead."

Some still favor relatively volatile stocks, among them William F. Sharpe, a retired Stanford University professor who won the 1990 Nobel Memorial Prize in Economic Science for theories based on beta. "It is a remarkable set of empirical results about what happened in the past," he said of the University of Chicago study. "But I am not willing to make investment decisions based on the theory that there is no relationship between beta, properly measured, and expected returns."

If Professors Fama and French are right, however, the impact could be far reaching. Some highly volatile groups of stocks that have enjoyed wide followings -- airlines, for example -- could lose a portion of their appeal if beta-believing investors side with the professors.

Additionally, many executives of publicly held companies have taken the view that if their own company's stock is more volatile than the market as a whole, any project they invest in -- from a lowly piece of new equipment to a huge joint venture -- must generate an extra high return to compensate investors for swings in the stock's price and earnings. The professors' work could force many companies to rethink the way they approach capital spending, finance scholars say.

Finally, many publicly held utilities have used beta to justify rate requests. They figure the returns that investors demand, given their companies' betas, and develop rate structures that allow them to earn these returns. But recognizing that their low betas tend to argue against large rate increases, a growing number of utilities had already turned to other approaches. More will probably do so if the research of Professors Fama and French gains currency.

And if investors decide to quit following betas, other theories of market behavior are likely to gain influence. "What we are really taking about is opening the floodgates to a whole new generation of research into what truly drives stock prices," said Anthony B. Sanders, an Ohio State University professor of finance who is currently a visiting professor at the University of Chicago. "Once you hammer a model like the old one closed, you generate all sorts of additional academic interest."

Professor Fama has already won worldwide recognition for his efficient-markets theory -- the notion that because investors all have essentially the same information it is impossible to consistently earn returns greater than those justified by the risks.

Professor Sharpe used Professor Fama's theory as an assumption to develop the capital-asset pricing model, which links returns to risk, as measured by beta.

Professor Sharpe says that a diversified portfolio can reduce the risks peculiar to individual companies -- that General Motors stock, for example, will be hurt by a strike. Investors, therefore, earn no rewards for bearing this risk, according to the Sharpe theory.

But investors do earn higher returns for bearing the other type of risk, known as market risk, Professor Sharpe says. This risk, which remains even after an investor diversifies, depends on how much an individual stock is dragged up or down by the market as a whole. Stocks like that of the biotechnology company Genentech, which have betas of more than 1.0, are more volatile than the market, while stocks like that of the power company Consolidated Edison, which have betas of less than 1.0, are calmer than the market.

To calculate market risk, or beta, finance professionals compare changes in the prices of individual stocks with changes in market indicators like the Standard & Poor's 500- stock index. Professor Sharpe and his followers say that in general, the higher a stock's beta, or volatility relative to the market, the greater its long-term returns.

Professors Fama and French disagree. Their paper, just published by the University of Chicago's Center for Research in Security Prices, says that long-term returns depend not on beta, but on company size and price-to-book ratios. Smaller companies, as measured by the market value of their shares, and those with low prices relative to their book values have in fact outperformed the market, they say.

The professors theorize that investors view smaller companies as more vulnerable to economic downturns and therefore demand higher returns. They also say that low price-to-book ratios typically reflect financial problems, another reason for investors to demand higher returns.

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Professors Fama and French are by no means the first to fire an intellectual salvo at the capital-asset pricing model. Since Professor Sharpe developed the model in the early 1960's, a broad array of rival theories has emerged to explain stock price movements: the January effect, which says that stocks usually gain at the beginning of the year, to the weekend effect, which says stocks generally perform poorly on Mondays. Most recently, the arbitrage pricing theory says that stocks are driven by powerful economywide forces like unanticipated inflation and spikes in interest rates.

But finance experts say that Professors Fama and French have presented the most conclusive evidence against beta.

"What they have proven fairly rigorously is what other academics have been talking about for some time," said Richard Roll, a finance professor at the University of California at Los Angeles, who with others developed the arbitrage pricing theory.

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

The capital asset pricing model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often the only asset pricing model taught in these courses.[1]

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 to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive "market portfolio" that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it

[1] Although every asset pricing model is a capital asset pricing model, the finance profession reserves the acronym CAPM for the specific model of Sharpe (1964), Lintner (1965) and Black (1972) discussed here. Thus, throughout the paper we refer to the Sharpe-Lintner-Black model as the CAPM.

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legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

We begin by outlining the logic of the CAPM, focusing on its predictions about risk and expected return. We then review the history of empirical work and what it says about shortcomings of the CAPM that pose challenges to be explained by alternative models.

The Logic of the CAPM

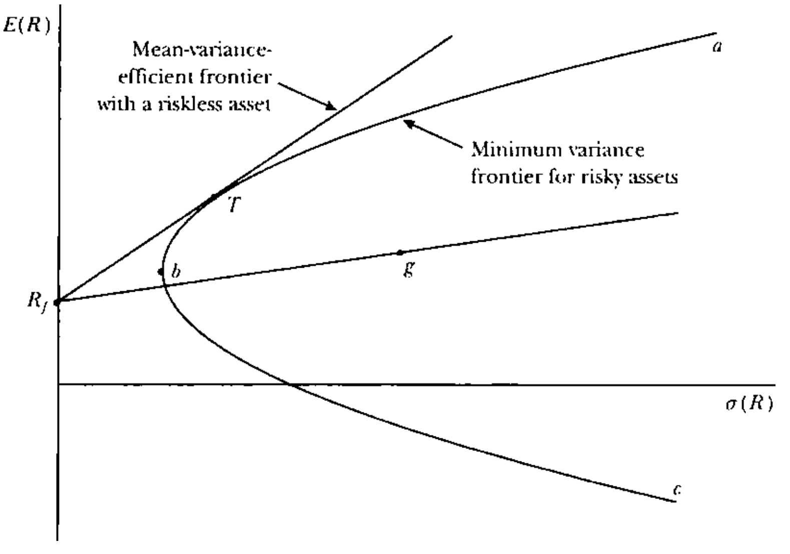
The CAPM builds on the model of portfolio choice developed by Harry Markowitz (1959). In Markowitz's model, an investor selects a portfolio at time $t-1$ that produces a stochastic return at t. The model assumes investors are risk averse and, when choosing among portfolios, they care only about the mean and variance of their one-period investment return. As a result, investors choose "mean-variance-efficient" portfolios, in the sense that the portfolios 1) minimize the variance of portfolio return, given expected return, and 2) maximize expected return, given variance. Thus, the Markowitz approach is often called a "mean-variance model."

The portfolio model provides an algebraic condition on asset weights in mean-variance-efficient portfolios. The CAPM turns this algebraic statement into a testable prediction about the relation between risk and expected return by identifying a portfolio that must be efficient if asset prices are to clear the market of all assets.

Sharpe (1964) and Lintner (1965) add two key assumptions to the Markowitz model to identify a portfolio that must be mean-variance-efficient. The first assumption is *complete agreement*: given market clearing asset prices at $t-1$, investors agree on the joint distribution of asset returns from $t-1$ to t. And this distribution is the true one—that is, it is the distribution from which the returns we use to test the model are drawn. The second assumption is that there is *borrowing and lending at a risk-free rate*, which is the same for all investors and does not depend on the amount borrowed or lent.

Figure 1 describes portfolio opportunities and tells the CAPM story. The horizontal axis shows portfolio risk, measured by the standard deviation of portfolio return; the vertical axis shows expected return. The curve *abc*, which is called the minimum variance frontier, traces combinations of expected return and risk for portfolios of risky assets that minimize return variance at different levels of expected return. (These portfolios do not include risk-free borrowing and lending.) The tradeoff between risk and expected return for minimum variance portfolios is apparent. For example, an investor who wants a high expected return, perhaps at point a, must accept high volatility. At point T, the investor can have an interme-

Figure 1
Investment Opportunities



diate expected return with lower volatility. If there is no risk-free borrowing or lending, only portfolios above *b* along *abc* are mean-variance-efficient, since these portfolios also maximize expected return, given their return variances.

Adding risk-free borrowing and lending turns the efficient set into a straight line. Consider a portfolio that invests the proportion *x* of portfolio funds in a risk-free security and $1 - x$ in some portfolio *g*. If all funds are invested in the risk-free security—that is, they are loaned at the risk-free rate of interest—the result is the point R_f in Figure 1, a portfolio with zero variance and a risk-free rate of return. Combinations of risk-free lending and positive investment in *g* plot on the straight line between R_f and *g*. Points to the right of *g* on the line represent borrowing at the risk-free rate, with the proceeds from the borrowing used to increase investment in portfolio *g*. In short, portfolios that combine risk-free lending or borrowing with some risky portfolio *g* plot along a straight line from R_f through *g* in Figure 1.[2]

[2] Formally, the return, expected return and standard deviation of return on portfolios of the risk-free asset *f* and a risky portfolio *g* vary with *x*, the proportion of portfolio funds invested in *f*, as

$$R_p = xR_f + (1 - x)R_g,$$

$$E(R_p) = xR_f + (1 - x)E(R_g),$$

$$\sigma(R_p) = (1 - x)\sigma(R_g), \; x \leq 1.0,$$

which together imply that the portfolios plot along the line from R_f through *g* in Figure 1.

To obtain the mean-variance-efficient portfolios available with risk-free borrowing and lending, one swings a line from R_f in Figure 1 up and to the left as far as possible, to the tangency portfolio T. We can then see that all efficient portfolios are combinations of the risk-free asset (either risk-free borrowing or lending) and a single risky tangency portfolio, T. This key result is Tobin's (1958) "separation theorem."

The punch line of the CAPM is now straightforward. With complete agreement about distributions of returns, all investors see the same opportunity set (Figure 1), and they combine the same risky tangency portfolio T with risk-free lending or borrowing. Since all investors hold the same portfolio T of risky assets, it must be the value-weight market portfolio of risky assets. Specifically, each risky asset's weight in the tangency portfolio, which we now call M (for the "market"), must be the total market value of all outstanding units of the asset divided by the total market value of all risky assets. In addition, the risk-free rate must be set (along with the prices of risky assets) to clear the market for risk-free borrowing and lending.

In short, the CAPM assumptions imply that the market portfolio M must be on the minimum variance frontier if the asset market is to clear. This means that the algebraic relation that holds for any minimum variance portfolio must hold for the market portfolio. Specifically, if there are N risky assets,

$$\text{(Minimum Variance Condition for } M\text{)} \quad E(R_i) = E(R_{ZM}) + [E(R_M) - E(R_{ZM})]\beta_{iM},\ i = 1, \ldots, N.$$

In this equation, $E(R_i)$ is the expected return on asset i, and β_{iM}, the market beta of asset i, is the covariance of its return with the market return divided by the variance of the market return,

$$\text{(Market Beta)} \quad \beta_{iM} = \frac{\text{cov}(R_i, R_M)}{\sigma^2(R_M)}.$$

The first term on the right-hand side of the minimum variance condition, $E(R_{ZM})$, is the expected return on assets that have market betas equal to zero, which means their returns are uncorrelated with the market return. The second term is a risk premium—the market beta of asset i, β_{iM}, times the premium per unit of beta, which is the expected market return, $E(R_M)$, minus $E(R_{ZM})$.

Since the market beta of asset i is also the slope in the regression of its return on the market return, a common (and correct) interpretation of beta is that it measures the sensitivity of the asset's return to variation in the market return. But there is another interpretation of beta more in line with the spirit of the portfolio model that underlies the CAPM. The risk of the market portfolio, as measured by the variance of its return (the denominator of β_{iM}), is a weighted average of the covariance risks of the assets in M (the numerators of β_{iM} for different assets).

Thus, β_{iM} is the covariance risk of asset i in M measured relative to the average covariance risk of assets, which is just the variance of the market return.[3] In economic terms, β_{iM} is proportional to the risk each dollar invested in asset i contributes to the market portfolio.

The last step in the development of the Sharpe-Lintner model is to use the assumption of risk-free borrowing and lending to nail down $E(R_{ZM})$, the expected return on zero-beta assets. A risky asset's return is uncorrelated with the market return—its beta is zero—when the average of the asset's covariances with the returns on other assets just offsets the variance of the asset's return. Such a risky asset is riskless in the market portfolio in the sense that it contributes nothing to the variance of the market return.

When there is risk-free borrowing and lending, the expected return on assets that are uncorrelated with the market return, $E(R_{ZM})$, must equal the risk-free rate, R_f. The relation between expected return and beta then becomes the familiar Sharpe-Lintner CAPM equation,

$$\text{(Sharpe-Lintner CAPM)} \quad E(R_i) = R_f + [E(R_M) - R_f)]\beta_{iM}, \; i = 1, \ldots, N.$$

In words, the expected return on any asset i is the risk-free interest rate, R_f, plus a risk premium, which is the asset's market beta, β_{iM}, times the premium per unit of beta risk, $E(R_M) - R_f$.

Unrestricted risk-free borrowing and lending is an unrealistic assumption. Fischer Black (1972) develops a version of the CAPM without risk-free borrowing or lending. He shows that the CAPM's key result—that the market portfolio is mean-variance-efficient—can be obtained by instead allowing unrestricted short sales of risky assets. In brief, back in Figure 1, if there is no risk-free asset, investors select portfolios from along the mean-variance-efficient frontier from a to b. Market clearing prices imply that when one weights the efficient portfolios chosen by investors by their (positive) shares of aggregate invested wealth, the resulting portfolio is the market portfolio. The market portfolio is thus a portfolio of the efficient portfolios chosen by investors. With unrestricted short selling of risky assets, portfolios made up of efficient portfolios are themselves efficient. Thus, the market portfolio is efficient, which means that the minimum variance condition for M given above holds, and it is the expected return-risk relation of the Black CAPM.

The relations between expected return and market beta of the Black and Sharpe-Lintner versions of the CAPM differ only in terms of what each says about $E(R_{ZM})$, the expected return on assets uncorrelated with the market. The Black version says only that $E(R_{ZM})$ must be less than the expected market return, so the

[3] Formally, if x_{iM} is the weight of asset i in the market portfolio, then the variance of the portfolio's return is

$$\sigma^2(R_M) = Cov(R_M, R_M) = Cov\left(\sum_{i=1}^{N} x_{iM}R_i, R_M\right) = \sum_{i=1}^{N} x_{iM}Cov(R_i, R_M).$$

premium for beta is positive. In contrast, in the Sharpe-Lintner version of the model, $E(R_{ZM})$ must be the risk-free interest rate, R_f, and the premium per unit of beta risk is $E(R_M) - R_f$.

The assumption that short selling is unrestricted is as unrealistic as unrestricted risk-free borrowing and lending. If there is no risk-free asset and short sales of risky assets are not allowed, mean-variance investors still choose efficient portfolios—points above *b* on the *abc* curve in Figure 1. But when there is no short selling of risky assets and no risk-free asset, the algebra of portfolio efficiency says that portfolios made up of efficient portfolios are not typically efficient. This means that the market portfolio, which is a portfolio of the efficient portfolios chosen by investors, is not typically efficient. And the CAPM relation between expected return and market beta is lost. This does not rule out predictions about expected return and betas with respect to other efficient portfolios—if theory can specify portfolios that must be efficient if the market is to clear. But so far this has proven impossible.

In short, the familiar CAPM equation relating expected asset returns to their market betas is just an application to the market portfolio of the relation between expected return and portfolio beta that holds in any mean-variance-efficient portfolio. The efficiency of the market portfolio is based on many unrealistic assumptions, including complete agreement and either unrestricted risk-free borrowing and lending or unrestricted short selling of risky assets. But all interesting models involve unrealistic simplifications, which is why they must be tested against data.

Early Empirical Tests

Tests of the CAPM are based on three implications of the relation between expected return and market beta implied by the model. First, expected returns on all assets are linearly related to their betas, and no other variable has marginal explanatory power. Second, the beta premium is positive, meaning that the expected return on the market portfolio exceeds the expected return on assets whose returns are uncorrelated with the market return. Third, in the Sharpe-Lintner version of the model, assets uncorrelated with the market have expected returns equal to the risk-free interest rate, and the beta premium is the expected market return minus the risk-free rate. Most tests of these predictions use either cross-section or time-series regressions. Both approaches date to early tests of the model.

Tests on Risk Premiums

The early cross-section regression tests focus on the Sharpe-Lintner model's predictions about the intercept and slope in the relation between expected return and market beta. The approach is to regress a cross-section of average asset returns on estimates of asset betas. The model predicts that the intercept in these regressions is the risk-free interest rate, R_f, and the coefficient on beta is the expected return on the market in excess of the risk-free rate, $E(R_M) - R_f$.

Two problems in these tests quickly became apparent. First, estimates of beta for individual assets are imprecise, creating a measurement error problem when they are used to explain average returns. Second, the regression residuals have common sources of variation, such as industry effects in average returns. Positive correlation in the residuals produces downward bias in the usual ordinary least squares estimates of the standard errors of the cross-section regression slopes.

To improve the precision of estimated betas, researchers such as Blume (1970), Friend and Blume (1970) and Black, Jensen and Scholes (1972) work with portfolios, rather than individual securities. Since expected returns and market betas combine in the same way in portfolios, if the CAPM explains security returns it also explains portfolio returns.[4] Estimates of beta for diversified portfolios are more precise than estimates for individual securities. Thus, using portfolios in cross-section regressions of average returns on betas reduces the critical errors in variables problem. Grouping, however, shrinks the range of betas and reduces statistical power. To mitigate this problem, researchers sort securities on beta when forming portfolios; the first portfolio contains securities with the lowest betas, and so on, up to the last portfolio with the highest beta assets. This sorting procedure is now standard in empirical tests.

Fama and MacBeth (1973) propose a method for addressing the inference problem caused by correlation of the residuals in cross-section regressions. Instead of estimating a single cross-section regression of average monthly returns on betas, they estimate month-by-month cross-section regressions of monthly returns on betas. The times-series means of the monthly slopes and intercepts, along with the standard errors of the means, are then used to test whether the average premium for beta is positive and whether the average return on assets uncorrelated with the market is equal to the average risk-free interest rate. In this approach, the standard errors of the average intercept and slope are determined by the month-to-month variation in the regression coefficients, which fully captures the effects of residual correlation on variation in the regression coefficients, but sidesteps the problem of actually estimating the correlations. The residual correlations are, in effect, captured via repeated sampling of the regression coefficients. This approach also becomes standard in the literature.

Jensen (1968) was the first to note that the Sharpe-Lintner version of the

[4] Formally, if x_{ip}, $i = 1, \ldots, N$, are the weights for assets in some portfolio p, the expected return and market beta for the portfolio are related to the expected returns and betas of assets as

$$E(R_p) = \sum_{i=1}^{N} x_{ip}E(R_i), \text{ and } \beta_{pM} = \sum_{i=1}^{N} x_{ip}\beta_{pM}.$$

Thus, the CAPM relation between expected return and beta,

$$E(R_i) = E(R_f) + [E(R_M) - E(R_f)]\beta_{iM},$$

holds when asset i is a portfolio, as well as when i is an individual security.

relation between expected return and market beta also implies a time-series regression test. The Sharpe-Lintner CAPM says that the expected value of an asset's excess return (the asset's return minus the risk-free interest rate, $R_{it} - R_{ft}$) is completely explained by its expected CAPM risk premium (its beta times the expected value of $R_{Mt} - R_{ft}$). This implies that "Jensen's alpha," the intercept term in the time-series regression,

$$\text{(Time-Series Regression)} \quad R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \varepsilon_{it},$$

is zero for each asset.

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat." Recall that, in cross-section regressions, the Sharpe-Lintner model predicts that the intercept is the risk-free rate and the coefficient on beta is the expected market return in excess of the risk-free rate, $E(R_M) - R_f$. The regressions consistently find that the intercept is greater than the average risk-free rate (typically proxied as the return on a one-month Treasury bill), and the coefficient on beta is less than the average excess market return (proxied as the average return on a portfolio of U.S. common stocks minus the Treasury bill rate). This is true in the early tests, such as Douglas (1968), Black, Jensen and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973) and Fama and MacBeth (1973), as well as in more recent cross-section regression tests, like Fama and French (1992).

The evidence that the relation between beta and average return is too flat is confirmed in time-series tests, such as Friend and Blume (1970), Black, Jensen and Scholes (1972) and Stambaugh (1982). The intercepts in time-series regressions of excess asset returns on the excess market return are positive for assets with low betas and negative for assets with high betas.

Figure 2 provides an updated example of the evidence. In December of each year, we estimate a preranking beta for every NYSE (1928–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stock in the CRSP (Center for Research in Security Prices of the University of Chicago) database, using two to five years (as available) of prior monthly returns.[5] We then form ten value-weight portfolios based on these preranking betas and compute their returns for the next twelve months. We repeat this process for each year from 1928 to 2003. The result is 912 monthly returns on ten beta-sorted portfolios. Figure 2 plots each portfolio's average return against its postranking beta, estimated by regressing its monthly returns for 1928–2003 on the return on the CRSP value-weight portfolio of U.S. common stocks.

The Sharpe-Lintner CAPM predicts that the portfolios plot along a straight

[5] To be included in the sample for year t, a security must have market equity data (price times shares outstanding) for December of $t - 1$, and CRSP must classify it as ordinary common equity. Thus, we exclude securities such as American Depository Receipts (ADRs) and Real Estate Investment Trusts (REITs).

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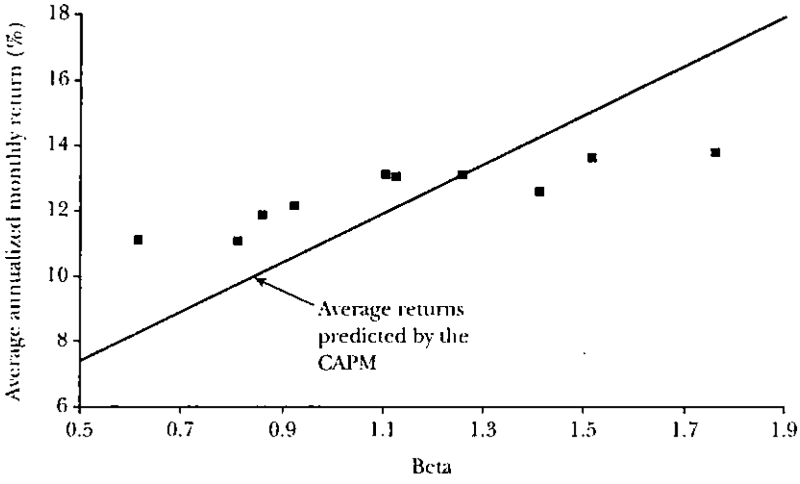
Figure 2

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



line, with an intercept equal to the risk-free rate, R_f, and a slope equal to the expected excess return on the market, $E(R_M) - R_f$. We use the average one-month Treasury bill rate and the average excess CRSP market return for 1928–2003 to estimate the predicted line in Figure 2. Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Lintner CAPM predicts. The returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.

Although the observed premium per unit of beta is lower than the Sharpe-Lintner model predicts, the relation between average return and beta in Figure 2 is roughly linear. This is consistent with the Black version of the CAPM, which predicts only that the beta premium is positive. Even this less restrictive model, however, eventually succumbs to the data.

Testing Whether Market Betas Explain Expected Returns

The Sharpe-Lintner and Black versions of the CAPM share the prediction that the market portfolio is mean-variance-efficient. This implies that differences in expected return across securities and portfolios are entirely explained by differences in market beta; other variables should add nothing to the explanation of expected return. This prediction plays a prominent role in tests of the CAPM. In the early work, the weapon of choice is cross-section regressions.

In the framework of Fama and MacBeth (1973), one simply adds predetermined explanatory variables to the month-by-month cross-section regressions of returns on beta. If all differences in expected return are explained by beta, the average slopes on the additional variables should not be reliably different from zero. Clearly, the trick in the cross-section regression approach is to choose specific additional variables likely to expose any problems of the CAPM prediction that, because the market portfolio is efficient, market betas suffice to explain expected asset returns.

For example, in Fama and MacBeth (1973) the additional variables are squared market betas (to test the prediction that the relation between expected return and beta is linear) and residual variances from regressions of returns on the market return (to test the prediction that market beta is the only measure of risk needed to explain expected returns). These variables do not add to the explanation of average returns provided by beta. Thus, the results of Fama and MacBeth (1973) are consistent with the hypothesis that their market proxy—an equal-weight portfolio of NYSE stocks—is on the minimum variance frontier.

The hypothesis that market betas completely explain expected returns can also be tested using time-series regressions. In the time-series regression described above (the excess return on asset *i* regressed on the excess market return), the intercept is the difference between the asset's average excess return and the excess return predicted by the Sharpe-Lintner model, that is, beta times the average excess market return. If the model holds, there is no way to group assets into portfolios whose intercepts are reliably different from zero. For example, the intercepts for a portfolio of stocks with high ratios of earnings to price and a portfolio of stocks with low earning-price ratios should both be zero. Thus, to test the hypothesis that market betas suffice to explain expected returns, one estimates the time-series regression for a set of assets (or portfolios) and then jointly tests the vector of regression intercepts against zero. The trick in this approach is to choose the left-hand-side assets (or portfolios) in a way likely to expose any shortcoming of the CAPM prediction that market betas suffice to explain expected asset returns.

In early applications, researchers use a variety of tests to determine whether the intercepts in a set of time-series regressions are all zero. The tests have the same asymptotic properties, but there is controversy about which has the best small sample properties. Gibbons, Ross and Shanken (1989) settle the debate by providing an *F*-test on the intercepts that has exact small-sample properties. They also show that the test has a simple economic interpretation. In effect, the test constructs a candidate for the tangency portfolio *T* in Figure 1 by optimally combining the market proxy and the left-hand-side assets of the time-series regressions. The estimator then tests whether the efficient set provided by the combination of this tangency portfolio and the risk-free asset is reliably superior to the one obtained by combining the risk-free asset with the market proxy alone. In other words, the Gibbons, Ross and Shanken statistic tests whether the market proxy is the tangency portfolio in the set of portfolios that can be constructed by combining the market portfolio with the specific assets used as dependent variables in the time-series regressions.

Enlightened by this insight of Gibbons, Ross and Shanken (1989), one can see a similar interpretation of the cross-section regression test of whether market betas suffice to explain expected returns. In this case, the test is whether the additional explanatory variables in a cross-section regression identify patterns in the returns on the left-hand-side assets that are not explained by the assets' market betas. This amounts to testing whether the market proxy is on the minimum variance frontier that can be constructed using the market proxy and the left-hand-side assets included in the tests.

An important lesson from this discussion is that time-series and cross-section regressions do not, strictly speaking, test the CAPM. What is literally tested is whether a specific proxy for the market portfolio (typically a portfolio of U.S. common stocks) is efficient in the set of portfolios that can be constructed from it and the left-hand-side assets used in the test. One might conclude from this that the CAPM has never been tested, and prospects for testing it are not good because 1) the set of left-hand-side assets does not include all marketable assets, and 2) data for the true market portfolio of all assets are likely beyond reach (Roll, 1977; more on this later). But this criticism can be leveled at tests of any economic model when the tests are less than exhaustive or when they use proxies for the variables called for by the model.

The bottom line from the early cross-section regression tests of the CAPM, such as Fama and MacBeth (1973), and the early time-series regression tests, like Gibbons (1982) and Stambaugh (1982), is that standard market proxies seem to be on the minimum variance frontier. That is, the central predictions of the Black version of the CAPM, that market betas suffice to explain expected returns and that the risk premium for beta is positive, seem to hold. But the more specific prediction of the Sharpe-Lintner CAPM that the premium per unit of beta is the expected market return minus the risk-free interest rate is consistently rejected.

The success of the Black version of the CAPM in early tests produced a consensus that the model is a good description of expected returns. These early results, coupled with the model's simplicity and intuitive appeal, pushed the CAPM to the forefront of finance.

Recent Tests

Starting in the late 1970s, empirical work appears that challenges even the Black version of the CAPM. Specifically, evidence mounts that much of the variation in expected return is unrelated to market beta.

The first blow is Basu's (1977) evidence that when common stocks are sorted on earnings-price ratios, future returns on high E/P stocks are higher than predicted by the CAPM. Banz (1981) documents a size effect: when stocks are sorted on market capitalization (price times shares outstanding), average returns on small stocks are higher than predicted by the CAPM. Bhandari (1988) finds that high debt-equity ratios (book value of debt over the market value of equity, a measure of leverage) are associated with returns that are too high relative to their market betas.

Finally, Statman (1980) and Rosenberg, Reid and Lanstein (1985) document that stocks with high book-to-market equity ratios (B/M, the ratio of the book value of a common stock to its market value) have high average returns that are not captured by their betas.

There is a theme in the contradictions of the CAPM summarized above. Ratios involving stock prices have information about expected returns missed by market betas. On reflection, this is not surprising. A stock's price depends not only on the expected cash flows it will provide, but also on the expected returns that discount expected cash flows back to the present. Thus, in principle, the cross-section of prices has information about the cross-section of expected returns. (A high expected return implies a high discount rate and a low price.) The cross-section of stock prices is, however, arbitrarily affected by differences in scale (or units). But with a judicious choice of scaling variable X, the ratio X/P can reveal differences in the cross-section of expected stock returns. Such ratios are thus prime candidates to expose shortcomings of asset pricing models—in the case of the CAPM, shortcomings of the prediction that market betas suffice to explain expected returns (Ball, 1978). The contradictions of the CAPM summarized above suggest that earnings-price, debt-equity and book-to-market ratios indeed play this role.

Fama and French (1992) update and synthesize the evidence on the empirical failures of the CAPM. Using the cross-section regression approach, they confirm that size, earnings-price, debt-equity and book-to-market ratios add to the explanation of expected stock returns provided by market beta. Fama and French (1996) reach the same conclusion using the time-series regression approach applied to portfolios of stocks sorted on price ratios. They also find that different price ratios have much the same information about expected returns. This is not surprising given that price is the common driving force in the price ratios, and the numerators are just scaling variables used to extract the information in price about expected returns.

Fama and French (1992) also confirm the evidence (Reinganum, 1981; Stambaugh, 1982; Lakonishok and Shapiro, 1986) that the relation between average return and beta for common stocks is even flatter after the sample periods used in the early empirical work on the CAPM. The estimate of the beta premium is, however, clouded by statistical uncertainty (a large standard error). Kothari, Shanken and Sloan (1995) try to resuscitate the Sharpe-Lintner CAPM by arguing that the weak relation between average return and beta is just a chance result. But the strong evidence that other variables capture variation in expected return missed by beta makes this argument irrelevant. If betas do not suffice to explain expected returns, the market portfolio is not efficient, and the CAPM is dead in its tracks. Evidence on the size of the market premium can neither save the model nor further doom it.

The synthesis of the evidence on the empirical problems of the CAPM provided by Fama and French (1992) serves as a catalyst, marking the point when it is generally acknowledged that the CAPM has potentially fatal problems. Research then turns to explanations.

One possibility is that the CAPM's problems are spurious, the result of data dredging—publication-hungry researchers scouring the data and unearthing contradictions that occur in specific samples as a result of chance. A standard response to this concern is to test for similar findings in other samples. Chan, Hamao and Lakonishok (1991) find a strong relation between book-to-market equity (B/M) and average return for Japanese stocks. Capaul, Rowley and Sharpe (1993) observe a similar B/M effect in four European stock markets and in Japan. Fama and French (1998) find that the price ratios that produce problems for the CAPM in U.S. data show up in the same way in the stock returns of twelve non-U.S. major markets, and they are present in emerging market returns. This evidence suggests that the contradictions of the CAPM associated with price ratios are not sample specific.

Explanations: Irrational Pricing or Risk

Among those who conclude that the empirical failures of the CAPM are fatal, two stories emerge. On one side are the behavioralists. Their view is based on evidence that stocks with high ratios of book value to market price are typically firms that have fallen on bad times, while low B/M is associated with growth firms (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1995). The behavioralists argue that sorting firms on book-to-market ratios exposes investor overreaction to good and bad times. Investors overextrapolate past performance, resulting in stock prices that are too high for growth (low B/M) firms and too low for distressed (high B/M, so-called value) firms. When the overreaction is eventually corrected, the result is high returns for value stocks and low returns for growth stocks. Proponents of this view include DeBondt and Thaler (1987), Lakonishok, Shleifer and Vishny (1994) and Haugen (1995).

The second story for explaining the empirical contradictions of the CAPM is that they point to the need for a more complicated asset pricing model. The CAPM is based on many unrealistic assumptions. For example, the assumption that investors care only about the mean and variance of one-period portfolio returns is extreme. It is reasonable that investors also care about how their portfolio return covaries with labor income and future investment opportunities, so a portfolio's return variance misses important dimensions of risk. If so, market beta is not a complete description of an asset's risk, and we should not be surprised to find that differences in expected return are not completely explained by differences in beta. In this view, the search should turn to asset pricing models that do a better job explaining average returns.

Merton's (1973) intertemporal capital asset pricing model (ICAPM) is a natural extension of the CAPM. The ICAPM begins with a different assumption about investor objectives. In the CAPM, investors care only about the wealth their portfolio produces at the end of the current period. In the ICAPM, investors are concerned not only with their end-of-period payoff, but also with the opportunities

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they will have to consume or invest the payoff. Thus, when choosing a portfolio at time $t-1$, ICAPM investors consider how their wealth at t might vary with future *state variables*, including labor income, the prices of consumption goods and the nature of portfolio opportunities at t, and expectations about the labor income, consumption and investment opportunities to be available after t.

Like CAPM investors, ICAPM investors prefer high expected return and low return variance. But ICAPM investors are also concerned with the covariances of portfolio returns with state variables. As a result, optimal portfolios are "multifactor efficient," which means they have the largest possible expected returns, given their return variances and the covariances of their returns with the relevant state variables.

Fama (1996) shows that the ICAPM generalizes the logic of the CAPM. That is, if there is risk-free borrowing and lending or if short sales of risky assets are allowed, market clearing prices imply that the market portfolio is multifactor efficient. Moreover, multifactor efficiency implies a relation between expected return and beta risks, but it requires additional betas, along with a market beta, to explain expected returns.

An ideal implementation of the ICAPM would specify the state variables that affect expected returns. Fama and French (1993) take a more indirect approach, perhaps more in the spirit of Ross's (1976) arbitrage pricing theory. They argue that though size and book-to-market equity are not themselves state variables, the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas. In support of this claim, they show that the returns on the stocks of small firms covary more with one another than with returns on the stocks of large firms, and returns on high book-to-market (value) stocks covary more with one another than with returns on low book-to-market (growth) stocks. Fama and French (1995) show that there are similar size and book-to-market patterns in the covariation of fundamentals like earnings and sales.

Based on this evidence, Fama and French (1993, 1996) propose a three-factor model for expected returns,

$$\text{(Three-Factor Model)} \quad E(R_{it}) - R_{ft} = \beta_{iM}[E(R_{Mt}) - R_{ft}] + \beta_{is}E(SMB_t) + \beta_{ih}E(HML_t).$$

In this equation, SMB_t (small minus big) is the difference between the returns on diversified portfolios of small and big stocks, HML_t (high minus low) is the difference between the returns on diversified portfolios of high and low B/M stocks, and the betas are slopes in the multiple regression of $R_{it} - R_{ft}$ on $R_{Mt} - R_{ft}$, SMB_t and HML_t.

For perspective, the average value of the market premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, which is 3.5 standard errors from zero. The average values of SMB_t, and HML_t are 3.6 percent and 5.0 percent per year, and they are 2.1 and 3.1 standard errors from zero. All three premiums are volatile, with annual standard deviations of 21.0 percent ($R_{Mt} - R_{ft}$), 14.6 percent (SMB_t) and 14.2 percent (HML_t) per year. Although the average values of the premiums are large, high volatility implies substantial uncertainty about the true expected premiums.

One implication of the expected return equation of the three-factor model is that the intercept α_i in the time-series regression,

$$R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \beta_{is}SMB_t + \beta_{ih}HML_t + \varepsilon_{it},$$

is zero for all assets i. Using this criterion, Fama and French (1993, 1996) find that the model captures much of the variation in average return for portfolios formed on size, book-to-market equity and other price ratios that cause problems for the CAPM. Fama and French (1998) show that an international version of the model performs better than an international CAPM in describing average returns on portfolios formed on scaled price variables for stocks in 13 major markets.

The three-factor model is now widely used in empirical research that requires a model of expected returns. Estimates of α_i from the time-series regression above are used to calibrate how rapidly stock prices respond to new information (for example, Loughran and Ritter, 1995; Mitchell and Stafford, 2000). They are also used to measure the special information of portfolio managers, for example, in Carhart's (1997) study of mutual fund performance. Among practitioners like Ibbotson Associates, the model is offered as an alternative to the CAPM for estimating the cost of equity capital.

From a theoretical perspective, the main shortcoming of the three-factor model is its empirical motivation. The small-minus-big (SMB) and high-minus-low (HML) explanatory returns are not motivated by predictions about state variables of concern to investors. Instead they are brute force constructs meant to capture the patterns uncovered by previous work on how average stock returns vary with size and the book-to-market equity ratio.

But this concern is not fatal. The ICAPM does not require that the additional portfolios used along with the market portfolio to explain expected returns "mimic" the relevant state variables. In both the ICAPM and the arbitrage pricing theory, it suffices that the additional portfolios are well diversified (in the terminology of Fama, 1996, they are multifactor minimum variance) and that they are sufficiently different from the market portfolio to capture covariation in returns and variation in expected returns missed by the market portfolio. Thus, adding diversified portfolios that capture covariation in returns and variation in average returns left unexplained by the market is in the spirit of both the ICAPM and the Ross's arbitrage pricing theory.

The behavioralists are not impressed by the evidence for a risk-based explanation of the failures of the CAPM. They typically concede that the three-factor model captures covariation in returns missed by the market return and that it picks up much of the size and value effects in average returns left unexplained by the CAPM. But their view is that the average return premium associated with the model's book-to-market factor—which does the heavy lifting in the improvements to the CAPM—is itself the result of investor overreaction that happens to be correlated across firms in a way that just looks like a risk story. In short, in the behavioral view, the market tries to set CAPM prices, and violations of the CAPM are due to mispricing.

The conflict between the behavioral irrational pricing story and the rational risk story for the empirical failures of the CAPM leaves us at a timeworn impasse. Fama (1970) emphasizes that the hypothesis that prices properly reflect available information must be tested in the context of a model of expected returns, like the CAPM. Intuitively, to test whether prices are rational, one must take a stand on what the market is trying to do in setting prices—that is, what is risk and what is the relation between expected return and risk? When tests reject the CAPM, one cannot say whether the problem is its assumption that prices are rational (the behavioral view) or violations of other assumptions that are also necessary to produce the CAPM (our position).

Fortunately, for some applications, the way one uses the three-factor model does not depend on one's view about whether its average return premiums are the rational result of underlying state variable risks, the result of irrational investor behavior or sample specific results of chance. For example, when measuring the response of stock prices to new information or when evaluating the performance of managed portfolios, one wants to account for known patterns in returns and average returns for the period examined, whatever their source. Similarly, when estimating the cost of equity capital, one might be unconcerned with whether expected return premiums are rational or irrational since they are in either case part of the opportunity cost of equity capital (Stein, 1996). But the cost of capital is forward looking, so if the premiums are sample specific they are irrelevant.

The three-factor model is hardly a panacea. Its most serious problem is the momentum effect of Jegadeesh and Titman (1993). Stocks that do well relative to the market over the last three to twelve months tend to continue to do well for the next few months, and stocks that do poorly continue to do poorly. This momentum effect is distinct from the value effect captured by book-to-market equity and other price ratios. Moreover, the momentum effect is left unexplained by the three-factor model, as well as by the CAPM. Following Carhart (1997), one response is to add a momentum factor (the difference between the returns on diversified portfolios of short-term winners and losers) to the three-factor model. This step is again legitimate in applications where the goal is to abstract from known patterns in average returns to uncover information-specific or manager-specific effects. But since the momentum effect is short-lived, it is largely irrelevant for estimates of the cost of equity capital.

Another strand of research points to problems in both the three-factor model and the CAPM. Frankel and Lee (1998), Dechow, Hutton and Sloan (1999), Piotroski (2000) and others show that in portfolios formed on price ratios like book-to-market equity, stocks with higher expected cash flows have higher average returns that are not captured by the three-factor model or the CAPM. The authors interpret their results as evidence that stock prices are irrational, in the sense that they do not reflect available information about expected profitability.

In truth, however, one can't tell whether the problem is bad pricing or a bad asset pricing model. A stock's price can always be expressed as the present value of expected future cash flows discounted at the expected return on the stock (Campbell and Shiller, 1989; Vuolteenaho, 2002). It follows that if two stocks have the same price, the one with higher expected cash flows must have a higher expected return. This holds true whether pricing is rational or irrational. Thus, when one observes a positive relation between expected cash flows and expected returns that is left unexplained by the CAPM or the three-factor model, one can't tell whether it is the result of irrational pricing or a misspecified asset pricing model.

The Market Proxy Problem

Roll (1977) argues that the CAPM has never been tested and probably never will be. The problem is that the market portfolio at the heart of the model is theoretically and empirically elusive. It is not theoretically clear which assets (for example, human capital) can legitimately be excluded from the market portfolio, and data availability substantially limits the assets that are included. As a result, tests of the CAPM are forced to use proxies for the market portfolio, in effect testing whether the proxies are on the minimum variance frontier. Roll argues that because the tests use proxies, not the true market portfolio, we learn nothing about the CAPM.

We are more pragmatic. The relation between expected return and market beta of the CAPM is just the minimum variance condition that holds in any efficient portfolio, applied to the market portfolio. Thus, if we can find a market proxy that is on the minimum variance frontier, it can be used to describe differences in expected returns, and we would be happy to use it for this purpose. The strong rejections of the CAPM described above, however, say that researchers have not uncovered a reasonable market proxy that is close to the minimum variance frontier. If researchers are constrained to reasonable proxies, we doubt they ever will.

Our pessimism is fueled by several empirical results. Stambaugh (1982) tests the CAPM using a range of market portfolios that include, in addition to U.S. common stocks, corporate and government bonds, preferred stocks, real estate and other consumer durables. He finds that tests of the CAPM are not sensitive to expanding the market proxy beyond common stocks, basically because the volatility of expanded market returns is dominated by the volatility of stock returns.

One need not be convinced by Stambaugh's (1982) results since his market proxies are limited to U.S. assets. If international capital markets are open and asset prices conform to an international version of the CAPM, the market portfolio should include international assets. Fama and French (1998) find, however, that betas for a global stock market portfolio cannot explain the high average returns observed around the world on stocks with high book-to-market or high earnings-price ratios.

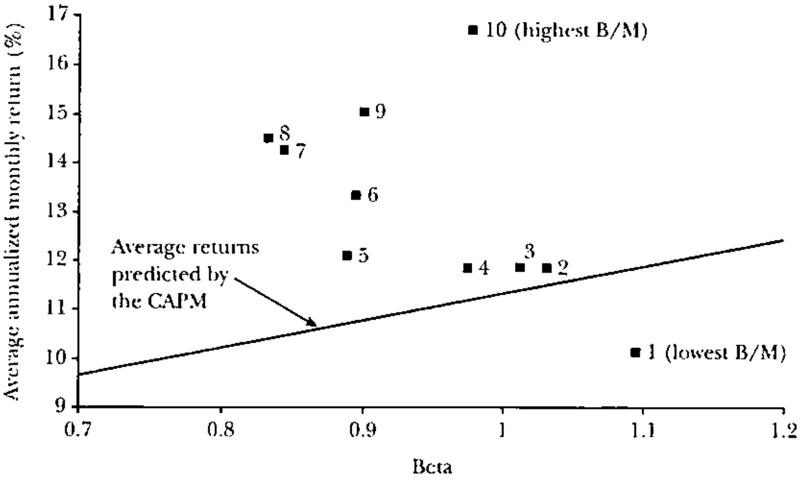
A major problem for the CAPM is that portfolios formed by sorting stocks on price ratios produce a wide range of average returns, but the average returns are not positively related to market betas (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1996, 1998). The problem is illustrated in Figure 3, which shows average returns and betas (calculated with respect to the CRSP value-weight portfolio of NYSE, AMEX and NASDAQ stocks) for July 1963 to December 2003 for ten portfolios of U.S. stocks formed annually on sorted values of the book-to-market equity ratio (B/M).[6]

Average returns on the B/M portfolios increase almost monotonically, from 10.1 percent per year for the lowest B/M group (portfolio 1) to an impressive 16.7 percent for the highest (portfolio 10). But the positive relation between beta and average return predicted by the CAPM is notably absent. For example, the portfolio with the lowest book-to-market ratio has the highest beta but the lowest average return. The estimated beta for the portfolio with the highest book-to-market ratio and the highest average return is only 0.98. With an average annualized value of the riskfree interest rate, R_f, of 5.8 percent and an average annualized market premium, $R_M - R_f$, of 11.3 percent, the Sharpe-Lintner CAPM predicts an average return of 11.8 percent for the lowest B/M portfolio and 11.2 percent for the highest, far from the observed values, 10.1 and 16.7 percent. For the Sharpe-Lintner model to "work" on these portfolios, their market betas must change dramatically, from 1.09 to 0.78 for the lowest B/M portfolio and from 0.98 to 1.98 for the highest. We judge it unlikely that alternative proxies for the market portfolio will produce betas and a market premium that can explain the average returns on these portfolios.

It is always possible that researchers will redeem the CAPM by finding a reasonable proxy for the market portfolio that is on the minimum variance frontier. We emphasize, however, that this possibility cannot be used to justify the way the CAPM is currently applied. The problem is that applications typically use the same

[6] Stock return data are from CRSP, and book equity data are from Compustat and the Moody's Industrials, Transportation, Utilities and Financials manuals. Stocks are allocated to ten portfolios at the end of June of each year t (1963 to 2003) using the ratio of book equity for the fiscal year ending in calendar year $t - 1$, divided by market equity at the end of December of $t - 1$. Book equity is the book value of stockholders' equity, plus balance sheet deferred taxes and investment tax credit (if available), minus the book value of preferred stock. Depending on availability, we use the redemption, liquidation or par value (in that order) to estimate the book value of preferred stock. Stockholders' equity is the value reported by Moody's or Compustat, if it is available. If not, we measure stockholders' equity as the book value of common equity plus the par value of preferred stock or the book value of assets minus total liabilities (in that order). The portfolios for year t include NYSE (1963–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stocks with positive book equity in $t - 1$ and market equity (from CRSP) for December of $t - 1$ and June of t. The portfolios exclude securities CRSP does not classify as ordinary common equity. The breakpoints for year t use only securities that are on the NYSE in June of year t.

Figure 3
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on B/M, 1963–2003



market proxies, like the value-weight portfolio of U.S. stocks, that lead to rejections of the model in empirical tests. The contradictions of the CAPM observed when such proxies are used in tests of the model show up as bad estimates of expected returns in applications; for example, estimates of the cost of equity capital that are too low (relative to historical average returns) for small stocks and for stocks with high book-to-market equity ratios. In short, if a market proxy does not work in tests of the CAPM, it does not work in applications.

Conclusions

The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success. In the early empirical work, the Black (1972) version of the model, which can accommodate a flatter tradeoff of average return for market beta, has some success. But in the late 1970s, research begins to uncover variables like size, various price ratios and momentum that add to the explanation of average returns provided by beta. The problems are serious enough to invalidate most applications of the CAPM.

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low.[7]

The CAPM is also often used to measure the performance of mutual funds and other managed portfolios. The approach, dating to Jensen (1968), is to estimate the CAPM time-series regression for a portfolio and use the intercept (Jensen's alpha) to measure abnormal performance. The problem is that, because of the empirical failings of the CAPM, even passively managed stock portfolios produce abnormal returns if their investment strategies involve tilts toward CAPM problems (Elton, Gruber, Das and Hlavka, 1993). For example, funds that concentrate on low beta stocks, small stocks or value stocks will tend to produce positive abnormal returns relative to the predictions of the Sharpe-Lintner CAPM, even when the fund managers have no special talent for picking winners.

The CAPM, like Markowitz's (1952, 1959) portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

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[7] The problems are compounded by the large standard errors of estimates of the market premium and of betas for individual stocks, which probably suffice to make CAPM estimates of the cost of equity rather meaningless, even if the CAPM holds (Fama and French, 1997; Pastor and Stambaugh, 1999). For example, using the U.S. Treasury bill rate as the risk-free interest rate and the CRSP value-weight portfolio of publicly traded U.S. common stocks, the average value of the equity premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, with a standard error of 2.4 percent. The two standard error range thus runs from 3.5 percent to 13.1 percent, which is sufficient to make most projects appear either profitable or unprofitable. This problem is, however, hardly special to the CAPM. For example, expected returns in all versions of Merton's (1973) ICAPM include a market beta and the expected market premium. Also, as noted earlier the expected values of the size and book-to-market premiums in the Fama-French three-factor model are also estimated with substantial error.

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Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Eight Gas Companies
5 Year Forecasted Growth Rates

	Time Period		Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Rate of Return (3=1+2)
(1)	52 Week Average Ending:	 March 24, 2015	3.69%	5.59%	9.28%
(2)	Spot Price Ending:	 March 24, 2015	3.61%	5.59%	9.20%
(3)	Average:		3.65%	5.59%	9.24%

Sources: Value Line March 6, 2015
Barrons March 24, 2015

Dividend Yields of Eight Company Peer Group

	Average	Atmos Energy	AGL Resources	Laclede Group	Northwest Natural Gas	Piedmont Natural	South Jersey Industries	Southwest Gas	WGL Holdings
Symbol		ATO	GAS	LG	NWN	PNY	SJI	SWX	WGL
Div		1.64	2.10	1.92	1.91	1.35	2.20	1.74	1.87
52 wk high		59.35	57.75	55.75	52.57	41.09	61.23	64.20	59.08
52 wk low		45.53	46.50	44.75	41.84	33.38	52.05	47.21	37.77
Spot Price		55.43	49.81	51.73	47.71	36.91	54.97	58.08	55.73
Spot Div Yield	3.61%	2.96	4.22	3.71	4.00	3.66	4.00	3.00	3.36
52 wk Div Yield	3.69%	3.13	4.03	3.82	4.05	3.63	3.88	3.12	3.86
Average	3.65%								

Source: Barrons March 24, 2015
Value Line March 6, 2015

Five Year Growth Estimate Forecast for Eight Company Barometer Group

Company	Symbol	Yahoo!	Zacks	Morningstar	Value Line	Average
		Source				
Atmos Energy	ATO	7.00%	7.00%	6.60%	7.00%	6.90%
AGL Resources	GAS	N/A	4.70%	4.50%	6.50%	5.23%
Laclede Group	LG	4.69%	4.90%	N/A	10.00%	6.53%
Northwest Natural Gas	NWN	4.00%	4.00%	4.00%	5.50%	4.38%
Piedmont Natural Gas	PNY	5.00%	5.00%	8.40%	3.00%	5.35%
South Jersey Industries	SJI	6.00%	6.00%	6.00%	7.50%	6.38%
Southwest Gas	SWX	4.00%	5.50%	2.40%	6.00%	4.48%
WGL Holdings Inc	WGL	6.50%	5.30%	5.60%	4.50%	5.48%
						5.59%

Source:
Internet

March 24, 2015

Company	Beta
Atmos Energy	0.85
AGL Resources	0.80
Laclede Group	0.70
Northwest Natural Gas	0.70
Piedmont Natural Gas	0.80
South Jersey Industries	0.80
Southwest Gas	0.85
WGL Holdings Inc	0.75
Average beta for CAPM	0.78

Source:
Value Line
March 6, 2015

CAPM with historical 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 =	4.2668
Rm =	11.4164
Be =	0.7813
Re =	9.85

Sources:	Value Line	March 6, 2015
	Blue Chip	Dec 1, 2014 & March 1, 2015

Risk Free Rate 10-year Treasury Note	Yield
5 Year Historic Average	2.49%
10 Year Historic Average	3.19%
20 Year Historic Average	4.13%
40 Year Historic Average	6.07%
62 Year Historic Average	5.45%
Average	4.27%

Source:
http://www.federalreserve.gov/releases/h15/data.htm

Required Rate of Return on Market as a Whole Historic

	Expected Market Return
5 yr S&P Composite Index Historical Return	16.06%
10 yr S&P Composite Index Historical Return	7.95%
20 yr S&P Composite Index Historical Return	9.99%
40 yr S&P Composite Index Historical Return	12.26%
62 yr S&P Composite Index Historical Return	10.82%
Average Expected Market Return =	11.42%

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	=	2.7475
Rm	=	9.8089
Be	=	0.7813
Re	=	8.26

Sources:	Value Line	March 6, 2015
	Blue Chip	Dec 1, 2014 & March 1, 2015

Risk Free Rate

Treasury note 10-yr Note	Yield
4Q 2014	2.28
1Q 2015	2.00
2Q 2015	2.20
3Q 2015	2.40
4Q 2015	2.70
1Q 2016	2.90
2Q 2016	3.10
2016-2020	4.40
Average	2.75

Source:
Blue Chip
Dec 1, 2014 & March 1, 2015

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	2.10%		7.79%	(a)	9.89%
S&P 500	2.08%	(b)	7.65%		9.73%
Average Expected Market Return				=	9.81%

(a) ((1+35%)^.25) -1) Value Line forecast for the 3 to 5 year index appreciation is 35%
(b) S&P 500 multiplied by half the growth rate

Sources:

Value Line	3/6/2015
S&P 500 Dividend Yield (Barrons)	3/24/2015
S&P 500 Growth Rate (Yahoo!)	3/24/2015

UTILITY STOCKS AND THE SIZE EFFECT: AN EMPIRICAL ANALYSIS

Annie Wong*

I. Introduction

The objective of this study is to examine whether the firm size effect exists in the public utility industry. Public utilities are regulated by federal, municipal, and state authorities. Every state has a public service commission with board and varying powers. Often their task is to estimate a fair rate of return to a utility's stockholders in order to determine the rates charged by the utility. The legal principles underlying rate regulation are that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks," and that the return to a utility should be sufficient to "attract capital and maintain credit worthiness." However, difficulties arise from the ambiguous interpretation of the legal definition of *fair and reasonable rate of return* to an equity owner.

Some finance researchers have suggested that the Capital Asset Pricing Model (CAPM) should be used in rate regulation because the CAPM beta can serve as a risk measure, thus making risk comparisons possible. This approach is consistent with the spirit of a Supreme Court ruling that equity owners sharing similar level of risk should be compensated by similar rate of return.

The empirical studies of Banz (1981) and Reinganum (1981) showed that small firms tend to earn higher returns than large firms after adjusting for beta. This phenomenon leads to the proposition that firm size is a proxy for omitted risk factors in determining stock returns. Barry and Brown (1984) and Brauer (1986) suggested that the omitted risk factor could be the differential information environment between small and large firms. Their argument is based on the fact that investors often have less publicly available information to assess the future cash flows of small firms than that of large firms. Therefore, an additional risk premium should be included to determine the appropriate rate of return to shareholders of small firms.

The samples used in prior studies are dominated by industrial firms, no one has examined the size effect in public utilities. The objective of this study is to extend the empirical findings of the existing studies by investigating whether the size effect is also present in the utility industry. The findings of this study have important implications for investors, public utility firms, and state regulatory agencies. If the size effect does exist in the utility industry, this would suggest that the size factor should be considered when the CAPM is being used to determine the fair rate of return for public utilities in regulatory proceedings.

II. Information Environment of Public Utilities

In general, utilities differ from industriales in that utilities are heavily regulated and they follow similar accounting procedures. A public utility's financial reporting is mainly regulated by the Securities and Exchange Commission (SEC) and the Federal Energy Regulatory Commission (FERC). Under the Public Utility Holding Company Act of 1935, the SEC is empowered to regulate the holding company systems of electric and gas utilities. The Act requires registration of public utility holding companies with the SEC. Only under strict conditions would the purchase, sale or issuance of securities by these holding companies be permitted. The purpose of the Act is to keep the SEC and investors informed of the financial conditions of these firms. Moreover, the FERC is in charge of the interstate operations of electric and gas companies. It requires utilities to follow the accounting procedures set forth in its Uniform Systems of Accounts. In particular, electric and gas utilities must request their Certified Public Accountants to certify that certain schedules in the financial reports are in conformity with the Commission's accounting requirements. These detailed reports are submitted annually and are open to the public.

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The FERC requires public utilities to keep accurate records of revenues, operating costs, depreciation expenses, and investment in plant and equipment. Specific financial accounting standards for these purposes are also issued by the Financial Accounting Standards Board (FASB). Uniformity is required so that utilities are not subject to different accounting regulations in each of the states in which they operate. The ultimate objective is to achieve comparability in financial reporting so that factual matters are not hidden from the public view by accounting flexibility.

Other regulatory reports tend to provide additional financial information about utilities. For example, utilities are required to file the FERC Form No. 1 with the state commission. This form is designed for state commissions to collect financial and operational information about utilities, and serves as a source for statistical reports published by state commissions.

Unlike industriales, a utility's earnings are predetermined to a certain extent. Before allowed earnings requests are approved, a utility's performance is analyzed in depth by the state commission, interest groups, and other witnesses. This process leads to the disclosure of substantial amount of information.

III. Hypothesis and Objective

Due to the Act of 1935, the Uniform Systems of Accounts, the uniform disclosure requirements, and the predetermined earnings, all utilities are reasonably homogeneous with respect to the information available to the public. Barry and Brown (1984) and Brauer (1986) suggested that the difference of risk-adjusted returns between small and large firms is due to their differential information environment. Assuming that the differential information hypothesis is true, then uniformity of information availability among utility firms would suggest that the size effect should not be observed in the public utility industry. The objective of this paper is to provide a test of the size effect in public utilities.

IV. Methodology

1. Sample and Data

To test for the size effect, a sample of public utilities and a sample of industriales matched by equity value are formed so that their results can be compared. Companies in both samples are listed on the Center for Research in Security Prices (CRSP) Daily and Monthly Returns files. The utility sample includes 152 electric and gas companies. For each utility in the sample, two industrial firms with similar firm size (one is slightly larger and the other is slightly smaller than the utility) are selected. Thus, the industrial sample includes 304 non-regulated firms.

The size variable is defined as the natural logarithm of market value of equity at the beginning of each year. Both the equally-weighted and value-weighted CRSP indices are employed as proxies for the market returns. Daily, weekly and monthly returns are used. The Fama-MacBeth (1973) procedure is utilized to examine the relation between risk-adjusted returns and firm size.

2. Research Design

All utilities in the sample are ranked according to the equity size at the beginning of the year, and the distribution is broken down into deciles. Decile one contains the stocks with the lowest market values while decile ten contains those with the highest market values. These portfolios are denoted by MV_1, MV_2, ..., and MV_{10}, respectively.

The combinations of the ten portfolios are updated annually. In the year after a portfolio is formed, equally-weighted portfolio returns are computed by combining the returns of the component stocks within the portfolio. The betas for each portfolio at year t, $\hat{\beta}_{pt}$'s, are estimated by regressing the previous five years of portfolio returns on market returns:

$$\tilde{R}_{pt} = \alpha_p + \hat{\beta}_{pt}\tilde{R}_{mt} + \tilde{U}_{pt} \qquad (1)$$

where

R_{pt} = periodic return in year t on portfolio p

R_{mt} = periodic market return in year t

U_{pt} = disturbance term.

Banz (1981) applied both the ordinary and generalized least squares regressions to estimate β; and concluded that the results are essentially identical (p.8). Since adjusting for heteroscedasticity does not necessarily lead to more efficient estimators, the ordinary least squares procedures are used in this study to estimate β in equation (1).

The following cross-sectional regression is then run for the portfolios to estimate γ_{it}, i = 0, 1, and 2:

$$R_{pt} = \gamma_{0t} + \gamma_{1t}\hat{\beta}_{pt} + \gamma_{2t}\hat{S}_{pt} + U_{pt} \qquad (2)$$

where

$\hat{\beta}_{pt}$ = estimated beta for portfolio p at year t, t=1968, ..., 1987

$\hat{S}_{pt}$ = mean of the logarithm of firm size in portfolio p at the beginning of year t

U_{pt} = disturbance term.

Depending on whether daily, weekly or monthly returns are used, a portfolio's average return changes periodically while its beta and size only change once a year. The γ_1 and γ_2 coefficients are estimated over the following four subperiods: 1968-72, 1973-77, 1978-82 and 1983-1987. If portfolio betas can fully account for the differences in returns, one would expect the average coefficient for the beta variable to be positive and for the size variable to be zero. A t-statistic will be used to test the hypothesis. The coefficients of a matched sample are also examined so that the results between industrial and utility firms can be compared.

V. Analysis of Results

1. Equity Value of the Utility Portfolios

The mean equity values of the ten size-based utility portfolios are reported in Table 1. Panels A and B present the average firm size of these portfolios at the beginning and end of the test period, 1968-1987. The first interesting observation from Table 1 is that the difference in magnitude between the smallest and the largest market value utility portfolios is tremendous. In Panel A, the average size of MV_1 is about \$31 million while that of MV_{10} is over \$1.4 billion. In Panel B, that is twenty years later, they are \$62 million and \$5.2 billion, respectively. Another interesting finding is that there is a substantial increase in average firm size from MV_9 to MV_{10}. Since these two findings are consistent over the entire test period, the average portfolio market values for interim years are not reported. These results are similar to the empirical evidence provided by Reinganum (1981).

The utility sample in this study contains 152 firms whereas Reinganum's sample contains 535 firms that are mainly industrial companies. Two conclusions may be drawn from the results of the Reinganum study and this one. First, utilities and industriales are similar in the sense that their market values vary over a wide spectrum. Second, the fact that there is a huge jump in firm size from MV_9 to MV_{10} indicates that the distribution of firm size is positively skewed. To correct for the skewness problem, the natural logarithm of the mean equity value of each portfolio is calculated. This variable is then used in later regressions instead of the actual mean equity value.

2. Betas of the Utility and Industrial Samples

The betas based on monthly, weekly and daily returns are reported for the utility and industrial samples. For simplicity, they will be referred to as monthly, weekly, and daily betas. In all cases, five years of returns are used to estimate the systematic risk. The betas estimated over the 1963-67 time period are used to proxy for the betas in 1968, which is the beginning of the test period. By the same token, the betas obtained from the time period 1982-86 are used as proxies for the betas in 1987, which is the end of the test period.

The betas from using the equally-weighted and value-weighted indices are calculated in order to check whether the results are affected by the choice of market index. Since the results are similar, only those obtained from the equally-weighted index are reported and analyzed.

Table 2 reports the monthly, weekly and daily betas of the two samples at the beginning and end of the test period. Panel A shows the various betas of the industrial portfolios. Two conclusions may be drawn. First, in the 1960's, smaller market value portfolios tend to have relatively larger betas. This is consistent with the empirical findings by Banz (1981) and Reinganum (1981). Second, this trend seems to vanish in the 1980's, especially when weekly and daily returns are used.

The betas of the utility portfolios are presented in Panel B. The table shows that none of the utility betas are greater than 0.71. A comparison between Panels A and B reveals that utility portfolios are relatively less risky than industrial portfolios after controlling for firm size. The comparison also reveals that, unlike industrial stocks, betas of the utility portfolios are not related to the market values of equity.

The negative correlation between firm size and beta in the industrial sample may introduce a multicolinearity problem in estimating equation (2). Banz (p.11) had addressed this issue and concluded that the test results are not sensitive to the

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multicolinearity problem. For the utility sample, this problem does not exist.

3. Tests on the Coefficients of Beta and Size

The beta and firm size are used to estimate γ_1 and γ_2 in equation (2). A t-statistic is used to test if the mean values of the gammas are significantly different from zero. The tests were performed for four 5-year periods which are reported in Table 3. The mean of the gammas and their t-statistic are presented in *Panel A* for the utilities and in Panel B for the industrial firms.

The empirical results for the utility sample are reported in Panel A of Table 3. When monthly returns are used, 60 regressions were run to obtain 60 pairs of gammas for each of the 5-year periods. When daily returns are used, over 1200 regressions were run for each period to obtain the gammas. The results are similar: in all of the time periods tested, none of the average coefficients for beta and size are significantly different from zero. When weekly returns are used, 260 pairs of gammas were obtained. *The average coefficients for beta are not significant* in any test period, and the average coefficients for size are not significant in three of the test periods. *For the test period of 1978-82, the average* coefficient for size is significantly negative at a 5% level.

The test results for the industrial sample are reported in Panel B of Table 3. When monthly returns are used, the average coefficient estimates for *size and beta are significant and have the expected* sign only in the 1983-87 test period. When weekly returns are used, only the size variable is significantly negative in the 1978-82 period. When daily returns are used, the coefficient estimates for betas and size are not significant at any conventional level.

According to the CAPM, beta is the sole determinant of stock returns. It is expected that the coefficient for beta is significantly positive. However, the empirical findings reported in this study and in Fama and French (1992) only provide weak support for beta in explaining stock returns. The empirical findings in this study also suggest that the size effect varies over time. It is not unusual to document the firm size effect at certain time periods but not at others. Banz (1981) found that the size effect is not stable over time with substantial differences in the magnitude of the coefficient of the size factor (p.9, Table 1). Brown, Kleidon and Marsh (1983) not only have shown that size effect is not constant over time but also have reported a reversal of the size anomaly for certain years.

The research design of this study allows us to keep the sample, test period, and methodology the same with the holding-period being the only variable. The size effect is documented for the industrial sample in one of the four test periods when monthly returns are used and in another when weekly returns are used. When daily returns are used, no size effect is observed. For the utility sample, the size effect is significant in only one test period when weekly returns are used. When monthly and daily returns are used, no size effect is found. Therefore, this study concludes that the size effect is not only time-period specific but also holding-period specific.

VI. Concluding Remarks

The fact that the two samples show different, though weak, *results indicates that utility* and industrial stocks do not share the same characteristics. First, given firm size, utility stocks are consistently less risky than *industrial stocks*. Second, industrial betas tend to decrease with firm size but utility betas do not. These findings may be *attributed to the fact that all public utilities* operate in an environment with regional monopolistic power and regulated financial structure. As a result, the *business and financial risks are very similar among* the utilities regardless of their sizes. Therefore, utility betas would not necessarily be expected to be related to firm size.

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 the 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 regulations.

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Table 1

Average Equity Size of the Utility Portfolios at the Beginning and End of the Test Period
(Dollar figures in millions)

	A: Beginning (1968)	B: End (1987)
MV_1	\$31	\$62
MV_2	\$77	\$177
MV_3	\$113	\$334
MV_4	\$161	\$475
MV_5	\$220	\$715
MV_6	\$334	\$957
MV_7	\$437	\$1,279
MV_8	\$505	\$1,805
MV_9	\$791	\$2,665
MV_{10}	\$1,447	\$5,399

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Table 2

Betas of the Two Samples at the Beginning and End of the Test Period

	Monthly Betas		Weekly Betas		Daily Betas	
	1963-67	1982-86	1963-67	1982-86	1963-67	1982-86
Panel A: Industrial Firms						
MV_1	0.89	1.00	1.15	0.95	1.11	0.92
MV_2	0.94	0.87	1.07	1.01	1.14	1.01
MV_3	0.88	0.82	1.12	0.86	1.14	1.04
MV_4	0.69	0.74	1.00	0.83	1.03	0.86
MV_5	0.73	0.80	1.05	0.96	1.13	1.01
MV_6	0.66	0.82	1.03	1.01	1.05	1.04
MV_7	0.64	0.81	0.97	1.04	0.98	1.09
MV_8	0.62	0.75	0.97	1.11	1.00	1.20
MV_9	0.52	0.78	0.84	1.06	0.94	1.16
MV_{10}	0.43	0.65	0.78	1.01	0.86	1.22
Panel B: Public Utilities						
MV_1	0.30	0.37	0.31	0.43	0.30	0.40
MV_2	0.28	0.38	0.37	0.47	0.36	0.44
MV_3	0.22	0.42	0.33	0.42	0.31	0.49
MV_4	0.27	0.35	0.36	0.52	0.34	0.54
MV_5	0.25	0.45	0.37	0.61	0.35	0.62
MV_6	0.25	0.41	0.39	0.54	0.40	0.65
MV_7	0.20	0.35	0.34	0.54	0.37	0.63
MV_8	0.17	0.38	0.34	0.65	0.33	0.68
MV_9	0.19	0.34	0.35	0.60	0.34	0.71
MV_{10}	0.18	0.29	0.38	0.59	0.39	0.71

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Table 3

Tests on the Mean Coefficients of Beta (γ_1) and Size (γ_2)

$$R_{pt} = \gamma_{ot} + \gamma_{1t}\hat{\beta}_{pt} + \gamma_{2t}\hat{S}_{pt} + U_{pt}$$

Returns Used:		Monthly (t-value)	Weekly (t-value)	Daily (t-value)
Panel A: Utility Sample				
1968-72	γ_1	-0.46% (-0.26)	-0.32% (-0.42)	-0.02% (-0.18)
	γ_2	-0.07% (-0.78)	-0.01% (-0.51)	-0.00% (-0.46)
1973-77	γ_1	-0.28% (-0.13)	0.14% (0.14)	-0.03% (-0.21)
	γ_2	-0.11% (-0.70)	-0.03% (-0.67)	-0.00% (-0.53)
1978-82	γ_1	0.55% (0.36)	0.54% (1.00)	0.05% (0.43)
	γ_2	-0.10% (-0.75)	-0.05% (-1.71)*	-0.01% (-1.60)
1983-87	γ_1	1.74% (1.28)	-0.24% (-0.51)	-0.02% (-0.18)
	γ_2	-0.16% (-1.54)	-0.03% (-0.86)	-0.01% (-0.63)
Panel B: Industrial Sample				
1968-72	γ_1	-0.36% (-0.27)	-0.28% (-0.55)	-0.02% (-0.32)
	γ_2	0.07% (0.43)	-0.01% (-0.19)	0.00% (0.51)
1973-77	γ_1	1.34% (0.64)	-0.23% (-0.31)	0.14% (1.45)
	γ_2	-0.01% (-0.06)	-0.04% (-0.85)	-0.00% (-0.64)
1978-82	γ_1	-0.84% (-0.28)	-0.56% (-0.91)	-0.09% (-0.81)
	γ_2	-0.29% (-0.75)	-0.01% (-1.72)*	-0.00% (-1.33)
1983-87	γ_1	2.51% (1.83)*	0.34% (0.64)	0.11% (1.40)
	γ_2	-0.25% (-1.90)*	-0.01% (-0.43)	0.00% (0.14)

* Significant at the 5% level based on a one-tailed test.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-049:

Reference Columbia Statement No. 4, p. 12 and Ex. 4, Sch. 2, p. 7, incentive compensation. For the 2014 and the 2015 Performance Years. Provide the following:

A. Copies of all incentive plan documents, including but not limited to those that include the terms and conditions of the plan(s);

B. Identification of each and every incentive plan target and the FPFTY amount expensed/capitalized attributable to each target;

C. A list of all the financial triggers and their specified minimum performance standard to be achieved in order for any incentive amounts to become payable under the incentive plan;

D. The number of the Company's eligible participants;

E. The positions held by the Company's eligible participants for each plan;

F. Copies of a representative Performance Management Worksheet from each eligible position level of the Company, marking the applicable position level on each worksheet provided; and

G. Whether financial goals or triggers must be met before any incentive compensation is paid. If not, identify the portion of FPFTY incentive compensation expensed/capitalized that is paid independent of whether financial goals are met.

Response:

A. Copies of incentive plan documents for 2014 are included in the response to GAS-RR-027. Copies of incentive plan documents for 2015 are attached to this request as I&E-RE-49 Attachment A and Attachment B.

B. For 2014, the incentive plan goals were $1.66 net operating earnings per share for NiSource, $220 million NiSource Gas Distribution business unit net operating earnings, and $397 million NiSource Gas Distribution business unit funds from operations.

For 2015, the incentive plan goals are $1.75 net operating earnings per share for NiSource, $238 million NiSource Gas Distribution business unit net operating earnings, and $537 million NiSource Gas Distribution business unit funds from operations.

The incentive included in the FPFTY period is $2,326,000. The portion assigned to expense and included in the claim is $1,735,000 as shown on Exhibit 104, Schedule 1, Page 2, Line 2, Column 7. The difference, or $591,000, reflects the portion assigned to capital. This claim is based on the assumption the incentive plan goals are met at the target payout levels.

C. For 2014, the incentive plan triggers were $1.61 net operating earnings per share for NiSource, $214 million NiSource Gas Distribution business unit net operating earnings, and $287 million NiSource Gas Distribution business unit funds from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.61, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

For 2015, the incentive plan triggers were $1.70 net operating earnings per share (NOEPS) for NiSource, $232 million NiSource Gas Distribution business unit net operating earnings, and $465 million NiSource Gas Distribution business unit funds from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.70, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

For exempt employees, the incentive payout opportunity is two-thirds discretionary and one-third non-discretionary. The discretionary portion of the incentive program is based on performance management linked to goals including customer, employee, process/capability, and financial goals for Columbia Gas. Performance management is executed through the annual evaluative process embodied in the Performance Management Worksheet ("PMW").

A Columbia Gas employee's PMW contains annual performance objectives and articulates the means of measuring the employee's progress in relation to the objectives established. Each employee is actively involved in the development of his or her PMW, with input from his or her supervisor, and the employee's progress is reviewed and discussed with the employee periodically throughout the year.

The use of the PMW process to establish goals to measure employees' performance against these goals is important in reinforcing the proper focus on key initiatives and goals designed to improve customer service, improve safety, and reinforce cost containment. Examples of goals included in a PMW include: (1) enhance public safety; (2) enhance emergency response procedures and training; (3) implement emergency response improvements; and (4) meet or exceed safety targets for E&C and contractors.

See the response to subpart F for copies of employee PMWs.

D. For 2014, 584 employees were eligible. For 2015, approximately 616 employees are eligible.

E. See I&E-RE-49 Attachment C for a list of titles of all eligible employees in 2014 and 2015 as of 4/30/15.

F. See I&E-RE-49 Attachments D through H for PMWs. There is one PMW attached to represent each level of the Company.

G. For 2014 and 2015, the trigger for an incentive plan goal must be met in order for a payment for that goal to occur. If the Corporation's NOEPS for the Performance Year is less than the trigger, no amount is payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Rachel Maurer, hereby state that the facts set forth in the foregoing document, I&E Statement No. 1 and I&E Exhibit No. 1, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

August 4, 2015
Date

Rachel Maurer
Name

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PA PUC
SECRETARY'S BUREAU

I&E Statement No. 1-SR
Witness: Rachel Maurer

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Surrebuttal Testimony

of

Rachel Maurer

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I&E Stmt. 1-SR
R-2015-2468056
8-4-15
Harrisburg JS

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rachel Maurer. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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. ARE YOU THE SAME RACHEL MAURER WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 1 AND THE SCHEDULES IN I&E EXHIBIT NO. 1?

A. Yes.

Q. DO YOU HAVE ANY CORRECTIONS TO MAKE TO I&E STATEMENT NO. 1?

A. Yes. On page 71, line 4, I incorrectly stated that my recommendation is an overall return of 7.18% while the correct overall return should be 7.19%. As can be seen on page 5, line 17 and I&E Exhibit No. 1, Schedule 1, my recommendation for the overall return for Columbia Gas of Pennsylvania is 7.19%.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made by the Columbia Gas of Pennsylvania, Inc. (Columbia or Company) witnesses Paul R. Moul, Nicole M. Paloney, and Mark R. Kempic in their rebuttal testimony regarding rate of return topics including the cost of debt, the cost of common equity and the overall fair rate of return, which will be applied to the Company's rate base.

<u>SUMMARY OF MR. MOUL'S TESTIMONY</u>

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Mr. Moul disputes my recommendation of an appropriate proxy group, the Company's short-term debt cost rate, the use of methods other than the DCF, the DCF growth rate, the DCF dividend yield, the inclusion of a leverage adjustment the CAPM risk-free rate, the use of a geometric mean, my disagreement with his size adjustment, the Company's claimed higher risk, and my disagreement with his Risk Premium and Comparable Earnings methods.

<u>PROXY (BAROMETER) GROUP</u>

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul claims that the "percentage of revenue" requirement is not appropriate and that the percentage of gas assets to total assets and the percentage of gas income to total income are more appropriate.[1]

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

A. No. Revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If under 50% of revenues come from the regulated gas business sector, the companies are not comparable to the subject utility as they do not provide the same level of regulated business.

Finding the percent of utility assets that make up the total assets of a company is not always a reliable way of determining if a business is primarily a regulated utility. Assets are accounted for at the original cost minus depreciation, which means that the value of the asset depends on its age. Therefore, it is possible for the regulated utility segment of a company to predominately have assets that are depreciated. Although a utility may have assets that are depreciated, it does not always indicate the level of business the company does. A parent company can have most of its utility assets depreciated, but still do more business as a utility than as another business.

[1] Columbia Statement No. 108-R, pages 11-12.

Another reason that using the percent of utility assets to total assets does not always accurately represent the percent of utility business is that there are differences between businesses in the amount of capital needed. A utility with all new equipment may need a large level of assets to produce a small level of cash flow while another business may need only a small amount of assets to produce a large level of cash flow. Therefore, comparing the assets of a gas utility segment to the total assets of a company is not an appropriate criterion as it could be misleading.

Finally, a comparison of gas income to total income is not appropriate because income represents the ability to control costs and manage finances, not the business activity that is generated by a business line.

Q. HAVE YOU CHANGED YOUR PROXY GROUP AS A RESULT OF MR. MOUL'S REBUTTAL COMMENTS?

A. No. The percentage of revenue is an appropriate criterion, and as NiSource, UGI Corporation, and New Jersey Resources have an insufficient percentage of regulated utility revenues, they should not be included in the proxy group and compared to Columbia.

COST RATE OF SHORT-TERM DEBT

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR RECOMMENDED COST RATE OF SHORT-TERM DEBT.

A. Mr. Moul argues that my short-term debt cost rate proposal is unreasonable as Columbia's historical spread between LIBOR and Columbia's received rate is not relevant when determining the future spread. Mr. Moul also claims that NiSource Finance has no assurance of access to the commercial paper market in the future and thus it plays no role in the pricing of loans. Finally, Mr. Moul updates his short-term debt cost rate (and therefore his overall return recommendation) from 2.86% to 2.575% to take into account a lower spread from a pricing grid included in his exhibit and to include the latest Blue Chip forecast.[2]

Q. DO YOU AGREE WITH MR. MOUL'S ASSERTION THAT COLUMBIA'S HISTORICAL SPREAD IS NOT RELEVANT?

A. No. As stated in my direct testimony, Columbia's claim for short-term debt in Docket No. R-2012-2321748 was 1.90% and its claim for short-term debt in Docket No. R-2014-2406274 was 2.27%, while its actual cost over the last two years was only 0.76% on average. Columbia's cost was overstated by 1.14% in 2012 and 1.51% in 2014. Therefore, it is reasonable to review Columbia's

[2] Columbia Statement No. 108-R, pages 9-11.

historical spread to determine a reasonable rate for the future as an inflated short-term debt cost rate would only serve to inflate the overall return and cause an unnecessary burden on ratepayers. The calculation of the historic spread merely reflects the difference between the actual LIBOR rate and the actual short-term debt rate received by Columbia. Since the spread is calculated using actual known and measurable data, it is reasonable to use this historic spread in the calculation of Columbia's short-term debt.

Q. DO YOU AGREE THAT HISTORICAL PRICES ARE NOT RELEVANT IF NISOURCE HAS NO GUARANTEE OF ACCESS TO THE COMMERCIAL PAPER MARKET?

A. No. Simply because an ad infinitum guarantee of access to the commercial paper market does not exist for NiSource does not mean that the analysis of historical spreads is not useful in evaluating the Company's claimed short-term debt cost rate. Mr. Moul has presented no information nor does he claim to suspect that NiSource will be unable access commercial paper markets and therefore not provide short-term debt financing to Columbia. In short, Mr. Moul's objection to my use of a historical spread is baseless.

Q. DO ANY OF MR. MOUL'S OBJECTIONS CHANGE YOUR SHORT-TERM DEBT COST RATE RECOMMENDATION?

A. No. I continue to recommend a short-term debt cost rate of 1.95% which is more than generous as it is higher than any of Columbia's short-term debt cost rates incurred in the last 24 months (December 2012-November 2014).

DISCOUNTED CASH FLOW (DCF)

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that results of a DCF analysis should be given considerable weight but disagrees with my approach. Mr. Moul disagrees with my results based on the outcomes of individual companies and disputes the growth rate I used. He improperly recalculates a DCF based on his claims which includes his leverage adjustment.[3]

ALLEGED EXCLUSIVE USE OF THE DCF

Q. WHAT IS MR. MOUL'S POSITION REGARDING YOUR USE OF THE DCF?

A. Mr. Moul alleges that my cost of equity analysis appears to rely almost exclusively on the DCF method and that the use of more than one method provides a superior

[3] Columbia Statement No. 108-R, pages 13-30.

foundation for the cost of equity determination. Mr. Moul claims that the use of more than one method will capture the multiplicity of factors that motivate investors.[4]

Q. WERE ANY METHODS OTHER THAN THE DCF EMPLOYED IN YOUR ANALYSIS?

A. Yes. Although my recommendation was based primarily on the results of my DCF, I also employed the CAPM as a comparison. The result of my DCF is 9.24%, which is squarely within the results of my CAPM range of 8.26% to 9.85%. For the reasons discussed in I&E Statement No. 1, I find the DCF method to be the most reliable. I have taken into account the fact that no method can perfectly predict the return on equity; therefore, I also use the CAPM as a comparison to the DCF. Although no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF does not make the end result more reliable. I agree with Mr. Moul that a proper determination of the cost of equity should not rely on one method. Where we disagree is to what extent one should rely on each particular method.

[4] Columbia Statement No. 108-R, page 13, lines 7-15.

EVALUATING THE DCF BASED ON INDIVIDUAL RESULTS

Q. WHAT IS MR. MOUL'S POSITION REGARDING THE RESULTS OF YOUR DCF?

A. Mr. Moul claims that when the individual company results do not fall into his definition of "reasonable," the application of the method should be questioned and points to the DCF results for Northwest Natural Gas and Southwest Gas as "anomalous" results.[5]

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. MOUL's METHOD OF DISAGGREGATING YOUR RESULTS?

A. Yes. A bias can be created when individual companies are removed based solely on the results. I chose criteria for my barometer group with the intention of creating a group that is comparable to Columbia, and then calculated a DCF from the companies that fit my criteria. To manipulate the results by eliminating a company because the results of its individual DCF are too high or too low, especially without a set definition of what a "reasonable" range is, would be to manipulate the results of one's DCF to fit one's own preconceived notion of what the result should be while ignoring what is happening in the market. Mr. Moul's analysis based on individual companies serves only to inflate his results by removing low results. My analysis, however, does not create a bias as the

[5] Columbia Statement No. 108-R, page 14.

selection of companies for my barometer group is not based upon results, but rather based upon companies that have similar risk to that of the company. Mr. Moul's introduction of this bias is inappropriate as it serves only to inflate his calculated return in this case.

DIVIDEND YIELD ADJUSTMENT

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING HIS DIVIDEND YIELD ADJUSTMENT.

A. Mr. Moul claims there has been extensive research on the impact of the ex-dividend on stock prices. He further claims that the SEC gives significance to the ex-dividend adjustment. Finally, Mr. Moul claims that many financial publications provide ex-dividend adjusted yields.

Q. DO YOU AGREE WITH MR. MOUL'S CLAIMS ABOUT THE EX-DIVIDEND ADJUSTMENT?

A. No. Mr. Moul is confusing the term ex-dividend *date* with ex-dividend *adjustment*. These are two different concepts. I continue to support my direct testimony stating that the ex-dividend adjustment is inappropriate and unnecessary.[6] Mr. Moul has failed to provide any evidence in terms of academic

[6] I&E Statement No. 1, pages 40-42.

support, investor use, or financial publications, in which the dividend yield is adjusted for the ex-dividend date.

Q. IS THERE ACADEMIC SUPPORT FOR THE EX-DIVIDEND ADJUSTMENT?

A. No. Mr. Moul has provided voluminous information explaining the ex-dividend *date*. This information simply explains that it is the date by which an investor must own a stock to receive the next dividend payment. However, Mr. Moul has failed to provide academic evidence showing that any type of *adjustment* is made to the dividend yield for this information.

Q. HAS MR. MOUL PROVIDED ANY EVIDENCE WHICH DEMONSTRATES THAT INVESTORS MAKE THIS ADJUSTMENT?

A. No. Mr. Moul uses a statement by the Securities and Exchange Commission (SEC) to support his claim. I have attached the full article in I&E Exhibit No. 1-SR, Schedule No. 1. Mr. Moul uses only one paragraph of the statement in his effort to support his claim. In fact, the article does not support Mr. Moul's claim at all, but rather explains only that the ex-dividend *date* is important to investors in determining when they are entitled to stock and cash dividends based upon the date they bought the stock. Long-term stock holders generally do not run into a problem with ex-dividend dates, as they hold their stock through price cycles. Ex-dividend dates are relevant when an investor wants to exit ownership of a stock, but would like to receive the dividend first. Mr. Moul has failed to provide any evidence suggesting that investors make an *adjustment* to the dividend yield based on this ex-dividend date.

Q. DO ANY FINANCIAL PUBLICATIONS PUBLISH THE EX-DIVIDEND ADJUSTMENT?

A. No. As I previously testified, Mr. Moul is confusing the terms. The ex-dividend *date* is published in many financial publications. However, any specific *adjustment* made to the dividend yield based on this date is not published in any financial publication that I am aware of, including those listed by Mr. Moul. Mr. Moul also opines that the "x" listed in the Wall Street Journal signifies the lack of pricing change related to the dividend.[7] The "x" simply signifies that it is the "ex-dividend *date*." The x does not signify any *adjustment* being made to the dividend yield, as Mr. Moul proposes. Therefore, Mr. Moul has not supported his claim that financial publications support this adjustment.

[7] Columbia Statement No. 108-R, page 7, lines 19-22.

GROWTH RATE

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR GROWTH RATE AND LOG-LINEAR PROCESS.

A. Mr. Moul suggests a biased approach of excluding growth rates that are "abnormally low" and uses a Wall Street Journal article to claim that analysts' do not overestimate.[8]

Q. PLEASE COMMENT ON MR. MOUL'S REMOVAL OF THE GROWTH RATE FOR NORTHWEST NATURAL GAS AND SOUTHWEST GAS.

A. The removal of these growth rates is inappropriate for the same reason the removal of the DCF results for Northwest Natural Gas and Southwest Gas is inappropriate. It is inappropriate to remove a company based merely on the results.

Q. PLEASE COMMENT ON THE WALL STREET JOURNAL ARTICLE INCLUDED IN MR. MOUL'S REBUTTAL TESTIMONY.

A. Mr. Moul cites the Wall Street Journal article *Wall Street's Missed Expectations* which states that in any given quarter from 1999 to 2010 (when the article was written) 64% of companies have beaten analyst estimates. What the article fails to mention is the time horizon of the forecasts it uses to compare to the actual result.

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[8] Columbia Statement No. 108-R, pages 18-19.

The article authored by Professors Ciciretti, Dwyer, and Hasan cited in I&E Statement 1, page 27, states, "Many papers show that the analysts' forecast errors are predictably different from actual earnings. The evidence indicates that analysts' forecasts of earnings well before the announcement are higher on average than actual earnings." The article further states, "Some papers also suggest that analysts' forecasts close to the earnings announcement decline to less than the actual earnings."[9] The article explains that at twelve and six months, analysts' forecasts demonstrate a tendency towards over-estimating but at one month ahead, the forecasts are more similar to the actual numbers with more forecasts under-estimating than over-estimating. As neither Mr. Moul nor I have used a one-month growth rate, my statement that literature clearly demonstrates that analysts' over-estimate growth rates remains accurate.

Q. DO YOU AGREE WITH MR. MOUL'S RE-CALCULATION OF YOUR DCF?

A. No. Mr. Moul has calculated an erroneous dividend yield, and included an inappropriate dividend yield adjustment. Mr. Moul has also calculated an upwardly biased growth rate. Mr. Moul further included an inappropriate leverage

[9] 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) page 546.

adjustment as discussed in my direct testimony, I&E Statement No. 1.[10] Therefore, I continue to support my DCF equity cost rate of 9.24%.

LEVERAGE (MARKET-TO-BOOK) ADJUSTMENT

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS LEVERAGE ADJUSTMENT.

A. Mr. Moul states that the credit rating agencies do not measure the market-required cost of equity for a company, nor are they concerned with how it is applied in the rate-setting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of interest and principal by utilities. Mr. Moul states that the Blue Mountain case occurred during different economic conditions than those present today. He opines that the leverage adjustment rejected in the City of Lancaster decision, Docket No. R-2010-2179103 (Order entered July 14, 2011), is different than the leverage adjustment he proposes in this case. He inaccurately claims the Commission did not repudiate his adjustment in Aqua, and claims the Metropolitan Edison case is distinguishable. Mr. Moul suggests that he has used the academic literature and extended it into the rate-setting process. He opines that his leverage adjustment is routinely discussed in

[10] I&E Statement No. 1, pages 40-49.

the academic literature. Finally, Mr. Moul testifies that his "ku" factor is merely an iteration.[11]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S REBUTTAL TESTIMONY CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has actually supported the I&E argument that the leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of interest and principal by utilities (i.e., its financial risk).[12] Mr. Mouls's stated need for the leverage statement is the existence of more financial risk in book value capital structures[13]. He further contends that the book value of debt has nothing to do with his leverage adjustment. However, Mr. Moul attempts to support his leverage adjustment by stating the Company has more book leverage than market leverage, which means it has more book value debt than market value debt. By changing the equity ratio, Mr. Moul is also changing the debt ratio since the percentage of debt plus the percentage of equity must equal one hundred percent. However, in both cases, book value and market value, the actual amount of debt does not change, only its portion in the capital structure as it relates to equity. Therefore, there is no change in the amount of leverage. Since there is no change in the amount of debt, a leverage adjustment is not needed.

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[11] Columbia Statement No. 108-R, pages 24-28.
[12] Columbia Statement No. 108-R, page 24, lines 13-19.
[13] Columbia statement No. 8, page 32.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE RELEVANCE OF THE BLUE MOUNTAIN CASE TO THIS PROCEEDING?

A. Mr. Moul provided direct testimony in the Blue Mountain case, Blue Mountain Consolidated Water Company Statement No. 2, Docket No. R-781000686. On page 9, lines 12-15, Mr. Moul states that a multiple (above the book value of the stock) of 1.25 to 1 is desirable to maintain the financial integrity of presently invested equity and to attract future capital on a reasonable basis. On page 20, lines 3-5, he states that the common stock of the barometer group sold on average at only 85% of book value, and the group average was never above book value.

The above statements show that Mr. Moul advocated in the Blue Mountain case for a higher rate of return, to obtain market to book ratios above 1. However, Mr. Moul did not provide a leverage adjustment formula, which he has used in this proceeding. If he had used his leverage adjustment, it could have lowered the recommended return on equity, due to less "book leverage," or market to book below 1. The Blue Mountain case shows that Mr. Moul's recommendations are inconsistent.

Q. PLEASE COMMENT ON MR. MOUL'S TESTIMONY REGARDING YOUR MENTION OF THE METROPOLITAN EDISON CASE IN DIRECT TESTIMONY.

A. Mr. Moul claims that the MetEd case was distinguishable,[14] but has not explained how. Therefore, my direct testimony regarding the Commission's rejection of the leverage adjustment is still relevant, as it states, "The Commission did not accept the company's financial risk increment related to the leverage difference between market capital structures and book value capital structures."[15]

Q. PLEASE COMMENT ON MR. MOUL'S STATEMENT THAT THE COMMISSION DECLINED TO USE HIS LEVERAGE ADJUSTMENT IN AQUA, BUT DID NOT REPUDIATE THE ADJUSTMENT.

A. If it was indeed the case that the market value financial risk differed from the book value financial risk, the Commission would have needed to use the leverage adjustment in arriving at its rate of return on equity; however, it clearly did not. This supports the rejection of the adjustment in this case as well.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE CITY OF LANCASTER DECISION?

A. Mr. Moul contends that the adjustments proposed in this case and in the Lancaster case are different because the formulas used are different.[16] However, the theory behind the adjustment and the reasons for its use are exactly the same. In both cases, it was advocated that a leverage adjustment was needed due to the

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[14] Columbia Statement No. 108-R, page 25, lines 20-23.
[15] I&E Statement No. 1, pages 46-47.
[16] Columbia Statement No. 108-R, page 26, lines 8-15.

difference between market value capital structure and book value capital structure. The Commission rejected this proposed adjustment; therefore, the decision of the City of Lancaster supports the rejection of a leverage adjustment in this proceeding.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE LACK OF ACADEMIC LITERATURE SUPPORTING MR. MOUL'S ADJUSTMENT?

A. Mr. Moul testifies that financial leverage is referenced in the work of Modigliani and Miller and Hamada.[17] However, Mr. Moul has not disputed my direct testimony stating that his formula cannot be found in any literature, that he uses the referenced work in a way which was not advocated, and that the referenced literature does not account for financial risk. Therefore, the leverage adjustment should not be accepted.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S "KU" FACTOR?

A. Mr. Moul opines that his formula solving for "ku" is performed by an iterative process. He also claims that I&E-RR-005 essentially refutes my direct

[17] Columbia Statement No. 108-R, page 26, lines 16-22.

testimony.[18] Rather, the data request he refers to, I&E-RR-005, is actually the Microsoft Excel spreadsheet version of Mr. Moul's exhibit and clearly supports my direct testimony showing that "ku", unlike the DCF, is already solved for on the right hand side of the equation before the iterative process even begins. Mr. Moul has not shown a formula with the "ku" term on one side of the equation, which is customary in mathematics when solving for a variable, nor has he disputed my direct testimony stating the same. Therefore, stating that his proposed leverage adjustment contains flaws related to the "ku" factor is accurate, and Mr. Moul's formula cannot be relied upon.

Q. PLEASE COMMENT ON MR. MOUL'S BELIEF THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE FUTURE CASH FLOWS THAT INVESTORS EXPECT TO REALIZE.

A. First, Mr. Moul is stating here that investors use the DCF (discounted cash flow) method to determine their required return, as future cash flow is the concept behind the DCF method. However, earlier in his testimony he argues that more than one method must be used, and the DCF alone is not appropriate. Therefore, according to Mr. Moul, investors look at information other than simply future cash flows, e.g. book value.

[18] Columbia Statement No. 108-R, page 27, lines 1-11.

Secondly, to say that an investor does not consider the book value listed in Value Line is to say investors do not use Value Line as a source.

Third, to say an investor is unconcerned with the book value debt (and therefore financial risk) of a utility is unsupported. Clearly an investor takes the financial risk of the utility into consideration when determining his required return.

Finally, market capitalization is not the same as market value capital structure. Market capitalization refers to the amount of shares outstanding multiplied by the current price, while market value capital structure refers to the current market debt cost over total equity and current market equity cost over total equity.

Therefore, Mr. Moul's contention that Value Line includes market capitalization data does not offer any support for his leverage adjustment.

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT.

A. Mr. Moul's claims regarding the credit rating agencies support the I&E position, the referenced cases show Mr. Moul's inconsistencies and support the rejection of the leverage adjustment, Mr. Moul lacks academic support for this adjustment, and his "ku" factor cannot be relied upon. For these reasons, the leverage adjustment should be rejected.

CAPITAL ASSET PRICING MODEL

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul believes I have used an understated risk-free rate of return, used incorrectly calculated historical market returns that do not reflect investor-expected market returns, and failed to make a size adjustment.[19]

RISK-FREE RATE

Q. WHAT IS MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY BOND?

A. Mr. Moul claims his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Bond because a longer-term bond is less susceptible to Federal policy actions.[20]

Q. WHAT ARE YOUR REASONS FOR USING A 10-YEAR TREASURY BOND AS OPPOSED TO A 30-YEAR TREASURY BOND?

A. As stated in I&E Statement No. 1, page 30, I chose the 10-year Treasury Bond as it balances the short-comings of the short-term T-Bill and the 30-year Treasury Bond. Long-term Treasury Bonds have substantial maturity risk associated with

[19] Columbia Statement No. 108-R, page 30, lines 18-21.
[20] Columbia Statement No. 108-R, page 31, lines 1-14.

the market risk and the risk of unexpected inflation. As such, my choice of a 10-year Treasury Bond is more appropriate.

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have used an understated risk-free rate of return. Mr. Moul continues to speculate that I should not give the same weight to the yield on the 10-year Treasury Notes for the fourth quarter of 2014 as I do for the entire five-year period 2016 to 2020. Mr. Moul states that by the time rates go into effect, all four quarters of 2014 will be historical. Next, Mr. Moul incorrectly recalculates the risk-free rate to be 4.1%.[21]

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK FREE RATE?

A. No. Mr. Moul's new calculation improperly proposes to give equal weight to each separate year from 2013 to 2017. The further out into the future one forecasts, the less reliable the estimates become; therefore, to give the less reliable estimates equal weight would not be prudent. It is more appropriate to weight the quarters and years as I have done in my direct testimony, as shown in I&E Exhibit No. 1,

[21] Columbia Statement No. 108-R, page 32.

Schedule No. 11, page 2. In addition, my calculation provides a balance of historical, measurable, and accurate yields and future estimates. Also, given that the further out one forecasts, the less reliable the information, using these time periods allows for a more accurate risk-free rate.

GEOMETRIC MEAN

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE USE OF AN ARITHMETIC MEAN RATHER THAN A GEOMETRIC MEAN.

A. Mr. Moul opines that the arithmetic mean should be used instead of the geometric mean in determining an appropriate market return. Mr. Moul claims that the geometric mean consists merely of a rate of return taken from two data points and that it cannot provide a reasonable representation of the market risk premium in the context of the CAPM. Mr. Moul also opines that the expected equity risk premium should always be calculated using the arithmetic mean, citing Stocks, Bonds, Bills & Inflation: 1996 Yearbook, Ibbotson Associates, 1996, pages153-154. Mr. Moul then recalculates the I&E historic average to be 12.85%.[22]

[22] Columbia Statement No. 108-R, pages 32-35.

Q. WHAT ARE THE TWO WAYS TO CALCULATE THE GEOMETRIC MEAN?

A. The two ways to calculate the geometric mean are: (1) by using the beginning and ending points; or (2) by using all points included in a set of data. I&E has included all data points in its calculation of the geometric mean.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE DEMONSTRATING THE SHORTCOMINGS OF APPLYING THE ARITHMETIC MEAN IN A REGULATORY SETTING?

A. Yes. Suppose a hypothetical investor has \$100 to invest over a two-year period. The first year the investor earns a 100% return so that his ending wealth at the end of the period 1 is \$200. The second year the investor has a -50% return (loses \$100) so that his ending wealth at the end of period 2 is \$100. It is quite clear that the investor has not earned a return since he ends the two-year period with the same \$100 that he started with. The calculated geometric return is 0% = $(\$100/\$100)^{\wedge 1/2}$, which shows the lack of increased wealth. However, the calculated arithmetic return is 25% = (100% - 50%)/2. This means an investor relying on the arithmetic mean would expect to have an ending wealth of \$125, but instead would only have an ending wealth of \$100. This illustrates the inherent bias of using the arithmetic mean to calculate period results. As a result, it is quite clear that the use of the arithmetic mean for cost of capital purposes in a regulatory setting will produce biased results and that the geometric mean is more accurate and appropriate.

Q. IS THE USE OF A GEOMETRIC MEAN FOR THE CALCULATION OF THE HISTORICAL CAPM INAPPROPRIATE AS MR. MOUL ASSERTS?

A. No. The geometric mean normalizes the returns or yields, and thus, it measures the change over more than one period. The arithmetic average is more susceptible to being influenced by outliers, and therefore is not as good of a representation of the central tendency of a set of numbers. I have chosen to use the geometric mean to calculate a historical return because I am calculating a historical CAPM. For the historical performance of the market to be a valid representation of the future, a geometric mean should be calculated in order to minimize the effect of any particular years that deviated from normal years. The arithmetic mean is influenced by any outliers in the data set, and therefore would be a better representation of the volatility of returns than it is of historical performance. One of the difficulties of calculating the CAPM is that the risk premium is measured by the difference between the return on the market and the risk-free rate, and since the return on the market and the risk-free rate do not always change in the same direction or by the same percent, the risk premium itself is not constant over time. When measuring a historical risk premium, these volatilities, and therefore the potential inaccuracies of the CAPM, are enhanced by the use of the arithmetic mean. The geometric mean more accurately represents the typical value and therefore is a better representation of the historical market risk premium, because it is not as influenced by fluctuation in the market as the arithmetic average.

Q. DO MR. MOUL'S QUOTES FROM THE IBBOTSON YEARBOOK INVALIDATE YOUR USE OF THE GEOMETRIC MEAN?

A. No. I have used the geometric mean to find a historical return while the Ibbotson Yearbook is arguing against the use of a geometric mean in a forecasted CAPM and discusses the use of the arithmetic mean in a forward looking CAPM. I have only used the geometric mean in my historic CAPM; therefore, the Ibbotson quotes used by Mr. Moul do not apply. As stated by Ibbotson, "The geometric mean is backward-looking."[23]

Q. DO YOU AGREE WITH MR. MOUL'S RECALCULATION OF YOUR HISTORICAL CAPM?

A. No. Mr. Moul's analysis only serves to confirm that the CAPM can be manipulated to generate different results, making it less reliable than the DCF, and that Mr. Moul's analysis is inaccurate.

[23] *2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook*, Morningstar Inc., 2015, page 83.

SIZE

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING SIZE.

A. Mr. Moul discusses his views on Dr. Wong's article as provided in I&E Exhibit No. 1, Schedule No. 12, stating that the article was authored 20 years ago and points to a Fama/French study that identified size as a separate factor that helps to explain returns.[24]

Q. DOES THE TIME ELAPSED SINCE AN ARTICLE WAS WRITTEN NECESSARILY INVALIDATE ITS RESULTS?

A. No. Although Mr. Moul states that enormous changes have occurred in the industry since the 1960s, he presents no evidence that these "changes" have caused a size adjustment to be needed. To the contrary, Dr. Wong's study demonstrated that one does *not* need to be made in the utility industry. As stated in I&E Statement No. 1, absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

Q. DOES THE FAMA/FRENCH STUDY REFUTE DR. WONG'S ARTICLE?

A. No. As discussed in I&E Statement No. 1, Dr. Wong's article presents evidence that although a size effect may exist for industrial stocks, it does not exist for

[24] Columbia Statement No. 108-R, pages 35-36.

utility stocks. As the Fama/French study is not specific to utility stocks, it does not demonstrate that a size effect exists in the utility industry.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSTMENT?

A. I continue to recommend that his use of the 1.14% size adjustment should not be employed in calculating the CAPM.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULTS. DO YOU AGREE WITH HIS RECALCULATION?

A. No. Mr. Moul's recalculation is incorrect for several reasons. First, Mr. Moul used an inaccurate risk-free rate and has used leveraged betas. However, Mr. Moul has not refuted my direct testimony regarding leveraged betas, and therefore leveraged betas should not be used in any recalculation of my CAPM. Also, Mr. Moul's size adjustment is unnecessary, as stated in my both my direct testimony and above. Because of these factors, a recalculation of the I&E CAPM is imprudent; any recalculation provided by Mr. Moul of the I&E CAPM is unreliable and unnecessary.

RISK PREMIUM

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RISK PREMIUM METHOD.

A. Mr. Moul opines that the Risk Premium approach provides a direct and complete reflection of a utility's risk and return. Mr. Moul's also claims that my statement that the Risk Premium method does not measure the current cost of equity as directly as the DCF is without foundation.[25]

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul claims that my statement, "the Risk Premium method does not measure the current cost of equity as directly as the DCF," is without foundation. However, he has not provided evidence to support his speculation. In my direct testimony, I have clearly testified how the two measures are different.[26] One such argument is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt, and adding to it an equity risk premium. Mr. Moul supports this statement by stating that the Risk Premium (RP) method uses a company's own borrowing rate, or in other words its own debt, and adds a risk premium to it, measuring equity through debt which is an indirect measure.

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[25] Columbia Statement No. 108-R, pages 37-38.
[26] I&E Statement No. 1, pages 18-21.

The DCF measures equity more directly through the stock information (using equity information), whereas the RP method measures equity indirectly through the use of debt information.

COMPARABLE EARNINGS

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE COMPARABLE EARNINGS (CE) METHOD.

A. Mr. Moul claims that the use of the CE method satisfies the comparability standard established in the Hope case.[27]

Q. DO YOU AGREE THAT COMPANIES USED BY MR. MOUL IN HIS CE METHOD ARE COMPARABLE TO COLUMBIA?

A. No. Some of the companies included in Mr. Moul's analysis are CostCo Wholesale, Ely Lilly and Company, McCormick & Co., and Sysco Corp. which all operate in industries not effected by the same factors faced by the utility industry. The difference is very clearly demonstrated through returns as high has 50.9% and 36.1%.[28] The CE method should be excluded because it is subjective as to which companies are comparable and it is debatable whether historic accounting values are representative of the future. Moreover, the Commission has long recognized

[27] Columbia Statement No. 108-R, pages 38-39.
[28] Columbia Exhibit No. 400, Schedule 14.

the problem with this method and as a result its historical usage in this regulatory forum has been minimal.

RISK

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING COLUMBIA'S RISK.

A. Mr. Moul argues that Columbia has higher risk than the barometer group by stating that the Distribution System Improvement Charge (DSIC) is already considered in my barometer group. Mr. Moul continues to observe that many other members of the barometer group have similar mechanisms.[29]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S RISK ANALYSIS?

A. Mr. Moul claims that the DSIC is already factored into the barometer group, and will not offset the Company's higher risk. However, the ability for the Company to earn a return of and a return on its infrastructure between rate cases reduces the regulatory lag associated with the higher infrastructure replacements after the test year. Mr. Moul does not consider this risk reducer or Columbia's use of a Fully Projected Future Test Year (FPFTY) in his analysis of Columbia's overall risks. Rather, Mr. Moul disregards the DSIC and FPFTY and adds basis points to his

[29] Columbia Statement No. 108-R, pages 39-41.

cost of equity for his perceived increased risk of Columbia. The competitive risk Mr. Moul claims exists for Columbia is much lower than he would lead one to believe.

Q. DOES MR. MOUL TAKE THE ADDITIONAL RISKS OF THE UNREGULATED PORTION OF THE BAROMETER GROUP INTO CONSIDERATION?

A. No. Mr. Moul fails to realize that the barometer group includes risks that Columbia does not face. The barometer group is simply a proxy for Columbia, which is as close to Columbia's risk as is publicly available. However, these companies are not 100% regulated like Columbia. Rather, these companies have a mix of unregulated businesses which may increase each company's risk as compared to Columbia. Therefore, while Columbia may have one risk that is slightly greater than the barometer group, the barometer group companies may have an offsetting risk.

<u>**FULLY PROJECTED FUTURE TEST YEAR**</u>

Q. PLEASE SUMMARIZE COMPANY WITNESS PALONEY'S REBUTTLE TO YOUR TESTIMONY REGARDING THE USE OF A FULLY PROJECTED FUTURE TEST YEAR (FPFTY).

A. Ms. Paloney correctly points out that while I support the use and acknowledge the benefits of a FPFTY, I do not attempt to make any adjustment to my recommended cost of common equity of 9.24%. Ms. Paloney also comments on the Regulatory Research Associates (RRA) report published by SNL, cited in I&E Statement No. 1, which indicates an expectation that the Commission may impose an adjustment to account for the perceived change in risk due to a more favorable regulatory framework.[30] She states, "If the rate of return allowance is going to be adjusted downward for use of a fully forecasted future test year, then the benefits of using this ratemaking tool will be substantially offset."[31]

Q. WHY DID YOU NOT ADJUST YOUR RECOMMENDED RETURN ON EQUITY TO ACCOUNT FOR DECREASED RISK DUE TO THE FPFTY?

A. As stated in my direct testimony, a particular basis point adjustment would be arbitrary as there is no way to determine a specific value the FPFTY has to an investor.

Q. PLEASE COMMENT ON MS. PALONEY'S STATEMENT REGARDING THE RRA REPORT AND PERCEIVED RISK.

A. As stated in my direct testimony, both debt investors and equity investor evaluators have recognized the benefits of the FPFTY. The combination of both a

[30] I&E Statement No. 1, page 70.
[31] Columbia Statement No. 106-R, page 6, lines 18-20

FPFTY and a DSIC mechanism is seen as a positive by the credit rating agencies and investors because there will be a more timely collection of investments.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MS. PALONEY'S REBUTTAL TESTIMONY ON THE COMMISSION'S CONSIDERATION OF RRA OR SNL ARTICLES?

A. There is no data showing that the Commission decisions take into consideration or are influenced by the expectations of RRA or SNL, because the decisions do not include in-depth explanations stating exactly how the Commission came to a particular decision. The decisions also do not list the sources the Commission considered. However, SNL is an available source for the Commission to use as a resource. The fact that the Commission does not disclose every source or article that could have influenced its decision-making process does not reduce the value of an RRA article.

Q. DO YOU AGREE WITH MS. PALONEY'S CLAIM THAT IF THE RATE OF RETURN ALLOWANCE IS ADJUSTED DOWNWARD FOR THE USE OF A FPFTY, THE BENEFITS OF USING THIS RATEMAKING TOOL WILL BE SUBSTANTIALLY OFFSET?

A. No. If Ms. Paloney's claim were true, it would mean that any changes in risk would not have an effect on the rate of return. The ability for the Company to forecast its rate base into the future allows for the determination that the plant going into rate base in the future will be allowed in rate base, as opposed to it being disallowed for whatever reason. Therefore, the risk that investors will not be paid back has been reduced. Furthermore, the ability to put rate base items not included in the base rate case into a DSIC mechanism between rate cases also decreases risk, because it allows for earlier recovery of that investment. It would be imprudent to allow a similar return to a company with these advantages as that of a company without them; the risks are different and should be acknowledged.

<u>MANAGEMENT EFFICIENCY POINTS</u>

Q. PLEASE SUMMARIZE COMPANY WITNESS KEMPIC'S TESTIMONY REGARDING MANAGEMENT EFFICIENCY POINTS.

A. Mr. Kempic claims that I have used an incorrect measure of Customer Assistance Program (CAP) participation rates and instead should have compared annual CAP participation to Low-Income Home Energy Assistance Program (LIHEAP) participation in Pennsylvania. Mr. Kempic also claims that Columbia having the most expensive Low Income Usage Reduction Program (LIURP) job cost and the most expensive CAP program demonstrates the Company's management efficiency.

Q. DO YOU AGREE WITH MR. KEMPIC THAT THE COMPARISON OF ANNUAL CAP PARTICIPATION TO LIHEAP PARTICIPATION IN PENNYSLVANIA IS A MORE APPROPRIATE MEASURE THAN MONTHLY CAP PARTICIPATION RATES?

A. No. The comparison of monthly CAP participation rates between gas utilities in Pennsylvania as presented by the Bureau of Consumer Service (BCS) report is appropriate as one measure of the Company's management performance as it is a comparison between companies of the same statistic. Mr. Kempic's proposal to compare Columbia's annual CAP participation rate to the participation in LIHEAP across Pennsylvania does not compare the same statistic as a utility customer can receive a LIHEAP grant without being a participant in CAP and can receive a LIHEAP grant and not assign it to Columbia.

Q. DO YOU AGREE WITH MR. KEMPIC THAT COLUMBIA HAVING THE MOST EXPENSIVE LOW INCOME USAGE REDUCTION PROGRAM (LIURP) JOB COST AND THE MOST EXPENSIVE CAP PROGRAM DEMONSTRATES THE COMPANY'S MANAGEMENT EFFICIENCY?

A. No. Although a variety of factors can influence the amount of money spent on both the CAP and LIURP programs, the long-term benefits of the programs need to be weighed against the affordability of these programs for the non participants who subsidize them, both low-income and non-low income. No matter how prudent the investment in the long run, in some cases there is an immediate need for money that prohibits any future investments, no matter how wise. I am not claiming that Columbia has failed to consider this aspect but merely pointing out that more money spent, no matter how much of a long-term benefit it might have, also has a short-term impact of a higher rate for customers and therefore more money spent on assistance programs does not always necessarily mean that customers should be required to pay for an increased return on equity through base rates. Ratepayers are not an ever expendable source of funds and cannot be viewed as such. Columbia should not receive additional equity basis points for monies collected from ratepayers and used to fund their CAP and LIURP programs. Viewing captive ratepayers as an ever expendable source of fund, without regard to cost and request addition equity basis points for the privilege is neither evidence of management effectiveness nor is it in the public interest.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MANAGEMENT EFFICIENCY POINTS?

A. For the reasons above and those described in I&E Statement No. 1, I recommend that the request for an additional 25 basis points be disregarded.

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOU DIRECT TESTIMONY?

A. No. I continue to support each recommendation made in I&E Statement No. 1.

Q. PLEASE SUMMARIZE YOUR OVERALL RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for Columbia:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.65 %	5.31 %	2.27 %
Short-Term Debt	5.14 %	1.95 %	0.10 %
Common Equity	52.21 %	9.24 %	4.82 %
Total	100.00 %		7.19 %

Source: I&E Exhibit No. 1, Schedule No. 1, Page 1.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 1-SR
Witness: Rachel Maurer

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Exhibit to Accompany

the

Surrebuttal Testimony

of

Rachel Maurer

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I&E Exhibit No. 1-SR
Page 1 of 3

Ex-Dividend Dates:

When Are You Entitled to Dividends

To determine whether you should get a dividend, you need to look at two important dates. They are the "record date" or "date of record" and the "ex-dividend date" or "ex-date."

When a company declares a dividend, it sets a record date when you must be on the company's books as a shareholder to receive the dividend. Companies also use this date to determine who is sent proxy statements, financial reports, and other information.

Once the company sets the record date, the ex-dividend date is set based on stock exchange rules. The ex-dividend date is usually set for stocks **two business days before** the record date. If you purchase a stock on its ex-dividend date or after, you will not receive the next dividend payment. Instead, the seller gets the dividend. If you purchase before the ex-dividend date, you get the dividend.

Here is an example:

Declaration Date	Ex-Dividend Date	Record Date	Payable Date
Friday, 7/26/2013	Thursday, 8/8/2013	Monday, 8/12/2013	Tuesday, 9/10/2013

On July 26, 2013, Company XYZ declares a dividend payable on September 10, 2013 to its shareholders. XYZ also announces that shareholders of record on the company's books on or before August 12, 2013 are entitled to the dividend. The stock would then go ex-dividend two business days before the record date.

In this example, the record date falls on a Monday. Excluding weekends and holidays, the ex-dividend is set two business days before the record date or the opening of the market—in this case on the preceding Thursday. This means anyone who bought the stock on Thursday or after would not get the dividend. At the same time, those who purchase before the ex-dividend date on Thursday will receive the dividend.

With a significant dividend, the price of a stock may fall by that amount after the ex-dividend date.

If the dividend is 25% or more of the stock value, special rules apply to the determination of the ex-dividend date. In these cases, the ex-dividend date will be deferred until one business day after the dividend is paid. In the above example, the ex-dividend date for a stock that's paying a dividend equal to 25% or more of its value, is September 11, 2013.

Sometimes a company pays a dividend in the form of stock rather than cash. The stock dividend may be additional shares in the company or in a subsidiary being spun off. The procedures for stock dividends may be different from cash dividends. The ex-dividend date is set the first business day after the stock dividend is paid (and is also after the record date).

If you sell your stock before the ex-dividend date, you also are selling away your right to the stock dividend. Your sale includes an obligation to deliver any shares acquired as a result of the dividend to the buyer of your shares, since the seller will receive an I.O.U. or "due bill" from his or her broker for the additional shares. Thus, it is important to remember that the day you can sell your shares without being obligated to deliver the additional shares is ***not*** the first business day after the record date, but usually is the first business day after the stock dividend is paid.

If you have questions about specific dividends, you should consult with your financial advisor.

I&E Exhibit No. 1-SR
Page 3 of 3

The Office of Investor Education and Advocacy has provided this information as a service to investors. It is neither a legal interpretation nor a statement of SEC policy. If you have questions concerning the meaning or application of a particular law or rule, please consult with an attorney who specializes in securities law.

Modified: Oct. 23, 2014

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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 EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. An outline of my education and employment experience 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 the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of the public, ratepayers, and the regulated utility.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or "Company"), and make recommended adjustments to the Company's proposed operating and maintenance ("O&M") expenses and rate base claims for the fully projected future test year ("FPFTY") ending December 31, 2016. My recommendations relate to the following ratemaking issues: rate case expense; labor and related taxes, NCSC – Shared Services, other employee benefits, and injuries and damages.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2, which accompanies this direct testimony, contains Schedules 1 through 10.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following tables summarize my recommended adjustments.

	Company Claim	I&E Adjustment	I&E Recommended Allowance
O&M Expenses:			
Rate Case Expense	$1,030,000	($206,000)	$824,000
Labor	$30,439,299	($1,827,317)	$28,611,982
FICA Tax		($132,523)	
NCSC – Shared Services	$31,646,290	($1,596,559)	$30,049,731
Other Employee Benefits	$5,090,000	($305,561)	$4,784,439
Injuries & Damages	$429,150	($95,325)	$333,825
Total O&M Expense Adjustments		($4,163,285)	

	Company Claim	I&E Adjustment	I&E Recommended Allowance
Rate Base Adjustments:			
Capitalized Labor	$22,766,957	($1,366,735)	$21,400,222
Capitalized FICA Tax		($99,120)	
Total Rate Base Adjustments		($1,465,855)	

RATE CASE EXPENSE

Q. IN THIS PROCEEDING THE COMPANY HAS MADE A CLAIM FOR RATE CASE EXPENSE. BRIEFLY EXPLAIN THE NATURE AND TYPES OF INDIVIDUAL EXPENDITURES TYPICALLY ALLOWED AS PART OF A UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a filing utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by computing the average number of months between the filing dates of a utility's previous rate cases.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY'S EXPECTED FILING FREQUENCY?

A. Yes. If the magnitude of the Company's continued accelerated pipeline investment (Columbia Gas Statement No. 1, p. 5) is such that it plans on filing annual base rate cases then Columbia should consider using its DSIC tariff to increase the lag between rate case filings. This will alleviate the impact on annual filings on ratepayers while ensuring safety through pipeline investment.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE IN THIS PROCEEDING?

A. The Company's total rate case expense is $1,030,000 which it normalized over one year, resulting in an annual claim of $1,030,000 (Columbia Gas Exhibit No. 104, Schedule 1, p. 2).

Q. DO YOU AGREE WITH THE COMPANY'S RATE CASE EXPENSE CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend the Company's rate case expense be normalized over a period of 15 months resulting in an annual expense of $824,000 ($1,030,000 ÷ 15 months x 12 months), or a reduction to the Company's annual rate case expense claim of $206,000 ($1,030,000 – $824,000).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I disagree with the Company's claimed one-year normalization period as it is not supported by the Company's historic record of filing frequency. Its proposed normalization period fails to properly rely upon historic data and is speculative in nature. As such, it should not be relied upon to determine the appropriate period to apply the normalization treatment.

In contrast to the Company's one-year normalization period, I recommend a 15 month normalization period. The normalization period of 15 months is a reasonable interval given the Company's actual base rate filing history over the most recent three cases. The Company's three most recent base rate case filing dates are as follows (I&E Ex. No. 2, Sch. 1):

Docket No.	Date Filed
R-2015-2468056	March 19, 2015
R-2014-2406274	March 21, 2014
R-2012-2321748	September 28, 2012

Using the Company's last three base rate case filing dates, an average interval is computed to be 15 months ((12 mo. + 18 mo.) ÷ 2 intervals). The Company's requested one-year recovery period is unsupported by the Company's historic filing record. Thus, a one year normalization period should be rejected as it would result in an unreasonable increase in rates.

LABOR AND RELATED TAXES

Q. WHAT IS INCLUDED IN THE COMPANY'S LABOR CLAIM?

A. The Company's labor claim includes annualized wages for regular payroll, overtime, premium pay, and net affiliate labor transferred (Columbia Gas Statement No. 4, pp. 10-11 and GAS-RR-026, p. 2). The Company has expensed and capitalized portions of its labor and related expenses by applying a historic labor capitalization ratio (Columbia Gas Exhibit No. 4, Schedule 2, p. 7).

Q. WHAT IS THE COMPANY'S CLAIM FOR LABOR?

A. The Company's claim for labor expense is $30,439,299 and $22,766,957 for capitalized labor as shown in the filing (Columbia Gas Exhibit No. 104, Schedule 1, p. 2 and GAS-RR-026, p. 2). Columbia Gas provided updated information regarding its claim in response to I&E-RE-57, showing a labor expense of $30,439,299 and $19,123,442 for capitalized labor mainly due to reclassifying capitalized training time to labor expense (I&E Ex. No. 2, Sch. 2, p. 3).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company started with its historic test year ("HTY") wages for 580 employees and made an adjustment to annualize for pay increases that occurred throughout the year. Next, the Company adjusted for normalized pay increases, anticipated increases for expected employee levels in the future test year ("FTY") and FPFTY periods, and training initiatives (Columbia Gas Statement No. 4, pp. 9-10 and p. 36; Statement No. 9, pp. 7-8; Exhibit No. 104, Schedule 2, p. 1; Exhibit No. 104, Schedule 10, pp. 1-2). Finally, the Company allocated amounts between capitalized and expensed (I&E Ex. No. 2, Sch. 2).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. HOW WILL YOUR RECOMMENDED ALLOWANCE BE PRESENTED?

A. My recommended allowances will based upon the Company's original claim for labor expense of $30,439,299 and $22,766,957 for capitalized labor. When the Company updates its filing to reflect revisions noted in response to I&E-RE-57 in rebuttal testimony, I will adjust my recommendation accordingly.

Q. WHAT DO YOU RECOMMEND FOR LABOR?

A. I recommend an allowance of $28,611,982 for labor expense, or a reduction of $1,827,317 ($30,439,299 - $28,611,982) to the Company's claim. Furthermore, I recommend an allowance of $21,400,222 for capitalized labor, or a reduction of $1,366,735 ($22,766,957 - $21,400,222) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED REDUCTION TO LABOR EXPENSE AND CAPITALIZED LABOR?

A. I recommend a labor reduction reflective of an average dollar value associated with normal staff vacancies and employee turnover. The Company claimed labor expense reflective of full staffing of all budgeted positions. While this is the ideal, it is not the reality. A review of the Company's vacancy levels over the last six months, December 1, 2014 through May 1, 2015, shows that in recent months, there were a significant number of vacancies. In order to fairly project FPFTY labor, it is reasonable to consider an average vacancy level associated with normal employee turnover.

Q. WHY DID YOU USE A SIX MONTH AVERAGE TO DETERMINE THE COMPANY'S AVERAGE NUMBER OF VACANCIES?

A. In the Company's response to I&E-RE-43 requesting monthly vacancy levels for the twelve months ended November 30, 2012, November 30, 2013, November 30, 2014, and December 1, 2014 through the current date, the Company provided monthly vacancy levels from December 1, 2014 through May 1, 2015 and year-end vacancy levels for the twelve months ended November 30, 2012, November 30, 2013, November 30, 2014 (I&E Ex. No. 2, Sch. 3). Therefore, I was unable to calculate a monthly vacancy rate for a period longer than six months. When the Company files the remaining requested information, I will update my recommendation in surrebuttal testimony accordingly.

Q. HOW DID YOU COMPUTE YOUR RECOMMENDED ALLOWANCE AMOUNTS FOR LABOR?

A. The Company submitted historic vacancy information in response to I&E-RE-43 (I&E Ex. No. 2, Sch. 3). This response provided monthly vacancy levels for December 1, 2014 through May 1, 2015 that I utilized to compute an average vacancy level of 38.

Next, I determined the average salary per employee for the Company's FPFTY to arrive at an average salary of $84,054 which I applied to the average monthly vacancy amount to arrive at a recommended labor reduction of $3,194,052 ($84,054 X 38).

Finally, I determined the amount attributed to expense and capital by dividing the Company's labor expense claim by the Company's total labor claim for an expense percentage of 57.21% ($30,439,299 / $53,206,256) and capitalization percentage of 42.79% ($22,766,957 / $53,206,256) which I applied these to my overall labor adjustment to determine my labor expense adjustment of $1,827,317 ($3,194,052 X 57.21%) and capitalized labor adjustment of $1,366,735 ($3,194,052 X 42.79%) (I&E Ex. No. 2, Sch. 4).

Q. ARE YOU RECOMMENDING ANY OTHER LABOR-RELATED ADJUSTMENTS?

A. Yes. It is necessary to make corresponding reductions to the Company's share of FICA tax expense and capitalized FICA taxes.

Q. WHAT ARE THOSE RECOMMENDED ADJUSTMENTS?

A. I recommend a corresponding reduction to FICA tax expense of $132,523 and a reduction to capitalized FICA taxes of $99,120.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. If my recommended adjustments to labor expense and capitalized labor are accepted, it will be necessary to reduce the Company's related FICA tax expense and capitalized FICA taxes. In determining the adjustments, I applied the

Company's HTY FICA Experience Factor of 7.2523% (Columbia Exhibit No. 106, Schedule 2, p. 3).

Q. HOW DID YOU COMPUTE YOUR RECOMMENDED ADJUSTMENTS TO FICA TAXES?

A. I multiplied my recommended reduction to labor expense of $1,827,317 by the Company's HTY FICA Experience Factor of 7.2523% to arrive at a recommended reduction of $132,523 ($1,827,317 X 0.072523) to FICA tax expense. Next, I multiplied my recommended reduction to capitalized labor of $1,366,735 by the same experience factor of 7.2523% to arrive at a recommended reduction to capitalized FICA taxes of $99,120 ($1,366,735 X 0.072523).

<u>NCSC – SHARED SERVICES</u>

Q. EXPLAIN WHAT IS INCLUDED IN NCSC – SHARED SERVICES?

A. NCSC – Shared Services consist of services provided by NiSource Corporate Services Company (NCSC), an affiliate of the Company including accounting and finance, legal services, real estate and facilities, information technology, human resources, and supply chain (Columbia Gas Statement No. 4, pp. 14-19).

Q. WHAT IS THE COMPANY'S CLAIM FOR NCSC – SHARED SERVICES?

A. The Company's claim for NCSC – Shared Services is $31,646,260 (Columbia Gas Exhibit No. 104, Schedule 1, p. 2).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR NCSC – SHARED SERVICES?

A. No.

Q. WHAT DO YOU RECOMMEND FOR NCSC – SHARED SERVICES?

A. I recommend an allowance of $30,049,731 for NCSC – Shared Services, or a reduction of $1,596,559 ($31,646,290 - $30,049,731) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company has included allocated profit sharing and stock rewards from NiSource, the affiliated service company (I&E Ex. No. 2, Sch. 5). The Company is claiming $1,708,588 in NiSource-allocated profit sharing and stock rewards expense which can be broken down into $191,703 for profit sharing and stock rewards of $1,516,885 less the phantom stock of $112,029 which the Company removed from the claim for NCSC – Shared Services for a total of $1,596,559 ($191,703 + $1,516,885 - $112,029) (I&E Ex. No. 2, Sch. 5, p. 2 and I&E Ex. No. 2, Sch. 6).

The Company has indicated that the profit sharing benefit is based on NiSource meeting its earnings per share goal (I&E Ex. No. 2, Sch. 7). These payouts appear to be made independent of quality of service, efficiency, or safety goals of Columbia Gas. Furthermore, the stock rewards are only available to top level NiSource employees and its affiliates (Columbia Gas Standard Data Request

GAS-RR-027, Att. B, p. 1). Ratepayers should not be obligated to pay for an expense that is based only on earnings goals and is unrelated to the provision of safe and reliable service.

OTHER EMPLOYEE BENEFITS

Q. EXPLAIN WHAT IS INCLUDED IN OTHER EMPLOYEE BENEFITS?

A. Other employee benefits consist of claims for the employee insurance plans (medical, dental, life, etc.), employee assistance program, post employee benefits, thrift plan, and profit sharing. (I&E Ex. No. 2, Sch. 5, p. 3)

Q. WHAT IS COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS?

A. The Company's claim for other employee benefits is $5,090,000 (Columbia Gas Exhibit No. 104, Schedule 1, p. 2).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $4,784,439 for other employee benefits, or a reduction of $305,561 ($5,090,000 - $4,784,439) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on my prior adjustment to labor for vacancies. I first determined the average other employee benefit cost per employee for the Company's FPFTY to arrive at an average of $8,041 ($5,090,000 / 633). I then applied the average other employee benefit expense to the average monthly vacancy amount from my prior adjustment to labor to arrive at the recommended other employee benefit expense reduction of $305,561 ($8,041 X 38) to arrive at my recommended allowance of $4,784,439 ($5,090,000 - $305,561) (I&E Exhibit No. 2, Sch. 8).

<u>**INJURIES AND DAMAGES**</u>

Q. WHAT IS COMPANY'S CLAIM FOR INJURIES AND DAMAGES?

A. The Company's claim for injuries and damages is $429,150 (Columbia Gas Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim for injuries and damages is based upon the last five years of injuries and damages expense which is adjusted using a Gross Domestic Product (GDP) deflator. The Company then used a five-year average to produce the HTY claim which the Company adjusted for inflation to produce the FTY and FPFTY claims (Columbia Gas Statement No. 4, p 12 and p. 40; Exhibit No. 4, Schedule 2, p. 11; and Exhibit No. 104, Schedule 2, p. 7).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR INJURIES AND DAMAGES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $333,825 for injuries and damages, or a reduction of $95,325 ($429,150 - $333,825) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a three-year historic average of injuries and damages rather than the five-year average used by the Company. In response to I&E-RE-17 (I&E Ex. No. 2, Sch. 9), which requested an explanation why injuries and damages for the twelve months ended November 30, 2010 were more than double that of the previous four years, the Company stated this was due to a workers' compensation claim totaling $163,659 in December 2009 and a higher level of general liabilities than in subsequent years. Thus, my recommendation based on using a three-year average is fair and reasonable and provides a more accurate estimate of expenses to be incurred for injuries and damages.

Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT TO THE COMPANY'S CLAIM?

A. For the HTY, I referred to the Company's Exhibit No. 4, Schedule 2, page 11, which provided the cost incurred for injuries for the twelve months ended November 30, 2012, November 30, 2013, and November 30, 2014 which I used to calculate a three-year historic average of $321,805 [($261,045 + $368,598 + $335,772) ÷ 3]. I then applied the inflation factor of 1.8385% to the HTY amount to calculate a FTY amount of $327,721 ($321,805 X 1.8385%). Finally, I applied the inflation factor of 1.8623% to the FTY amount to determine a FPFTY amount of $333,825 ($327,721 X 1.8623%) (I&E Ex. No. 2, Sch. 10).

SUMMARY OF I&E OVERALL POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $566,822,257. This recommended revenue requirement represents an increase of $11,192,977 to the I&E adjusted present rate revenues of $555,629,280. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimonies of I&E Witnesses Maurer (I&E St. No. 1) and Hubert (I&E St. No. 3).

A calculation of the I&E-recommended revenue requirement is shown below:

Columbia Gas of PA Inc		TABLE I			
R-2015-2468056		INCOME	SUMMARY		
6/16/15					
	12/31/16	INVESTIGATION & ENFORCEMENT			
	Proforma	[			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	534,899,150	20,730,130	555,629,280	11,192,977	566,822,257
Deductions:					
O&M Expenses	367,779,576	7,439,130	375,218,706	146,175	375,364,881
Depreciation	54,751,328	0	54,751,328		54,751,328
Taxes, Other	3,221,085	-132,523	3,088,562	0	3,088,562
Income Taxes:					
Current State	1,186,921	998,710	2,185,631	821,882	3,007,513
Current Federal	28,054,757	4,348,685	32,403,442	3,578,722	35,982,164
Deferred Taxes	-51,103	0	-51,103		-51,103
ITC	-360,240	0	-360,240		-360,240
Total Deductions	454,582,324	12,654,002	467,236,326	4,546,779	471,783,105
Income Available	80,316,826	8,076,128	88,392,954	6,646,198	95,039,152
Measure of Value	1,325,130,928	-1,465,855	1,323,665,073	0	1,323,665,073
Rate of Return	6.06%		6.68%		7.18%

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

Professional and Educational Experience

Christopher Keller

Professional Experience

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

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

Education and Training

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

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

Testimony Submitted

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

- Docket No. R-2014-2420279 – UGI Central Penn Gas, Inc., 1307(f)
- Docket No. R-2014-2419774 – Wellsboro Electric Company
- Docket No. R-2014-2428304 – Borough of Hanover – Hanover Municipal Water Works
- Docket No. R-2014-2452705 – Delaware Sewer Company
- Docket No. P-2014-2404341 – Delaware Sewer Company

APPENDIX A

Professional and Educational Experience

Christopher Keller

Assisted with the Following Cases

- Docket No. R-2013-2397353 – Pike County Light & Power Company (Gas)
- Docket No. R-2013-2397237 – Pike County Light & Power Company (Electric)
- Docket No. R-2014-2428742 – West Penn Power Company
- Docket No. R-2014-2428743 – Pennsylvania Electric Company
- Docket No. R-2014-2428744 – Pennsylvania Power Company
- Docket No. R-2014-2428745 – Metropolitan Edison Company
- Docket No. R-2014-2462723 – United Water Pennsylvania

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Rachel Maurer, hereby state that the facts set forth in the foregoing document, I&E Statement No. 1-SR and I&E Exhibit No. 1-SR, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

August 4, 2015
Date

Rachel Maurer
Name

I&E Exhibit No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES
RATE BASE

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-003:

Reference Columbia Gas of Pennsylvania, Inc. (Columbia or Company) Ex. 104, Schedule 2, p. 21 concerning rate case expense, provide the following for each of the most recent prior three base rate filings made by Columbia:

A. The case docket numbers, date of filing for each, and method of resolution, i.e., settlement or litigation;

B. The requested rate case expense and the actual rate case expense incurred for each filing;

C. The total revenue requested and the total revenue allowed by the Commission for each filing;

D. The actual effective dates of resulting rate changes.

Response:

ocket Number	Date of Filing	Method of Resolution	Estimated Rate Case Expense	Actual Rate Case Expense	Requested Overall Revenue Increase	Commission Approved Revenue Incease	Effective Date of Rate Increase
(A)	(A)	(A)	(B)	(B)	(C)	(C)	(D)
2014-2406274	3/21/2014	Settlement	$1,046,000	$458,570	$54,115,826	$32,500,000	12/20/2014
2012-2321748	9/28/2012	Settlement	$1,045,772	$587,487	$77,311,053	$55,250,000	7/1/2013
2010-2215623	1/28/2011	Partial-Settlement	$1,254,772	$1,105,441	$37,844,921	$17,000,000	10/18/2011

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-057:

Reference Columbia's response to Standard Data Request GAS-RR-26 concerning wages. Provide the following:

A. Explanation why total regular payroll from the HTY to the FTY increased by $5,681,313 or 15.2% although total employees only increased by 36 employees or 6.2% during the same time period;

B. Explanation why total regular payroll from the FTY to the FPFTY increased by $3,084,803 or 7.2% although total employees only increased by 17 employees or 2.8% during the same time period;

C. Explanation why total overtime payroll from the HTY to the FTY increased by $609,458 or 11.7%; and

D. Explanation why total overtime payroll from the FTY to the FPFTY increased by $419,283 or 6.7%.

Response:

A. Through D.

The Company does not prepare budgets at the total Payroll level. Since Budget data was not available in the format required for responding to Standard Data Request GAS-RR-026, certain data for the response to SDR GAS-RR-026 for the FTY and the FFRY were derived using the assumption that the future period's distribution of dollars amongst the type of labor (regular, overtime, premium and net affiliated labor) matched the HTY and the assumption that total Payroll Expense was 57.21% of Total Payroll and Capital Payroll was 42.79% of Total Payroll.

While performing the analysis to provide a response to this request, the Company has determined a better method of projecting total Payroll for the FTY and the FFRY was available and thus a revised response to SDR GAS-RR-026 would be appropriate. This revised response is provided in the form of Attachment A to this response and provides the detail of adjustments from the HTY to the FTY and then to the FFRY.

Attachment A, Columns 3, 4, 5 and 6 provide the details that determine a revised Total Payroll for the FTY; Columns 8, 9 and 10 provide the details that determine a revised Total Payroll for the FFRY. Please note that the total Payroll Expense has not changed for either period, however the amounts within each category of expense have changed slightly. Total Capital Payroll has changed based upon this revised method and better reflects amounts for wage increases (Columns 3 and 8), additional headcounts (Columns 4 and 9), time spent on training (Column 5) and ratemaking annualization adjustments to the headcount at the end of the HTY (Columns 6 and 10). Time spent on training involves training of existing employees. Since this training is an additional expense to budgeted labor, it represents increased payroll expense as a percentage of total payroll.

Based upon the revised response, Regular Payroll increases from the HTY to the FTY due to a 3% wage increase, additional headcount to support safety initiatives, ongoing compliance work, training and POD Assets and to reflect annualized payroll. Regular Payroll increases from the FTY to the FFRY due to a 3 % wage increase and 17 additional headcount including four damage prevention coordinators, four front line leaders, three maintenance & regulation techs and six restoration coordinators. Overtime Payroll includes a 3% wage increase for both FTY and FFRY as well as adjustments based upon budgeted work plans.

Description	Pre-HTY TME 11/30/2013	HTY TME 11/30/2014	Additional Headcount	FTY TME 11/30/2015	Additional Headcount	FFRY TME 12/31/2016
a.						
Employees						
Total Clerical Labor	56	68	3	71	2	73
Total Exempt Labor	99	111	0	111	4	115
Total Manual - Non-Union	10	11	0	11	4	15
Total Manual - Union	380	390	33	423	7	430
Total Employees	545	580	36	616	17	633

Description	Pre-HTY TME 11/30/2013	HTY TME 11/30/2014	3% of HTY	Additional Headcount	Time Spent on Training	Annualization Adjustment	FTY TME 11/30/2015	3% of FTY	Additional Headcount	Annualization Adjustment	FFRY TME 12/31/2016
b.,c.,d., and e											
	(1)	(2)	(3)=(2)x3%	(4)	(5)	(6)	(7)=(2)thru(6)	(8)=(7)less(6)x3%	(9)	(10)	(11)=(7)thru(10)
Payroll Expense											
Regular Payroll	21,526,009	22,156,700	664,701	1,021,852	519,361	328,201	24,690,815	730,878	1,008,345	(30,902)	26,399,136
Overtime Payroll	2,552,319	3,011,518	90,346	218,260			3,320,124	99,604	215,375		3,635,102
Premium Payroll	270,026	171,972	5,159				177,131	5,314			182,445
Net Affiliate Labor Transferred	867,985	209,836	6,295				216,131	6,484			222,615
Total Expense	25,216,339	25,550,026	766,501	1,240,112	519,361	328,201	28,404,201	842,280	1,223,720	(30,902)	30,439,299
Capital Payroll											
Regular Payroll	13,057,375	15,217,060	456,512	255,463	(519,361)	245,476	15,655,150	462,290	252,086	(23,112)	16,346,414
Overtime Payroll	1,676,031	2,231,030	66,931	54,565			2,352,526	70,576	53,844		2,476,945
Premium Payroll	155,381	127,402	3,822				131,224	3,937			135,161
Net Affiliate Labor Transferred	560,396	155,454	4,664				160,118	4,804			164,922
Total Capitalization	15,449,183	17,730,945	531,929	310,028	(519,361)	245,476	18,299,017	541,607	305,930	(23,112)	19,123,442
Total Payroll	**40,665,522**	**43,280,971**	**1,298,430**	**1,550,140**	**0**	**573,677**	**46,703,218**	**1,383,887**	**1,529,650**	**(54,014)**	**49,562,741**
Incentive Comp											
Expense	1,476,899	1,963,563					1,576,000				1,735,000
Capital	918,421	1,476,142					1,178,763				1,297,687
Total Incentive Comp	**2,395,320**	**3,439,705**					**2,754,763**				**3,032,687**

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-043:

Reference Columbia Ex. 104, Sch. 10, pp. 1-2 and Standard Data Request GAS-RR-26 concerning labor. Provide the following:

A. Monthly vacancy levels for the twelve months ended (TME):
   1. November 30, 2012;
   2. November 30, 2013;
   3. November 30, 2014; and
   4. December 1, 2014 through the current date.

B. The status of the additional positions to be filled in the FTY;

C. State whether Columbia still intends to fill all of the positions noted in Ex. 104, Sch. 10, pp. 1-2;

D. For the positions not yet filled, provide the current status of the unfilled positions (e.g., interviews currently underway, offers pending, etc.);

E. For all responses in Parts A-D, provide a detailed breakdown in a format similar to Standard Data Request GAS-RR-26, Part A;

F. Describe the procedures needed to fill vacant positions (e.g., review process, approval by upper management, etc.);

G. State whether Columbia has approved all of the additional positions to be filled; and

H. If not, state which positions have not yet been approved to date.

Response:

A. Monthly vacancy levels for the twelve months ended (TME):

11-30-12 - 75
11-30-13 - 63
11-30-14 – 30
12-1-14 - 30
1-1-15 - 32
2-1-15 - 32
3-1-15 - 53
4-1-15 – 39
5-1-15 - 39

While these vacancies are a normal part of our business the allotted work gets completed by outside contractors until the positions are filled to ensure that the budgeted work plan gets completed.

B. Please refer to Attachment A to this response. As the open positions are all budgeted vacancies, at this time, the Company intends to fill all open positions.

C. Yes, Columbia still intends to fill all of the positions noted in Ex. 104, Sch. 10, pp. 1-2.

D. Please refer to Attachment A. The positions not yet filled or posted are all in one of the following categories:

- Evaluated by leader; business needs review of job description and determine posting strategy
- Posted on union bulletin board. Per our Collective Bargaining agreements, all bargaining unit positions must be posted internally for a specified timeframe. Once awarded, the vacancy that was created (if a union position) also has to follow the same posting process. This continues until there are no internal bidders, at which time the position will be filled outside of the bargaining unit.
- Posted internal/external
- Interviews conducted
- Offers pending
- Training Class pending

E. Please refer to Attachment B to this response.

F. The Company utilized the follows steps to fill vacant positions:

1. Business needs evaluation.
2. Posted
3. Interviews
4. Offer
5. Background checks

G. Columbia has approved all of the additional positions to be filled.

H. Not applicable as all positions have been approved.

Position Creation Date	Job Title	Location	Desc	Status	Date Job Filled
12/1/2014	Analyst II	Smithfield PA-Call Ctr	Exempt	Filled	3/2/2015
12/1/2014	Damage Prevention Coordinator	York PA-Op Ctr	Clerical	Filled	12/28/2014
12/1/2014	Plant/Service Specialist	Greencastle PA Mod Site	Manual	Filled	2/9/2015
12/1/2014	Customer Service B	Hanover PA MOD Site	Manual	Filled	1/25/2015
2/1/2015	Construction Coordinator	Bridgeville PA - Op Ctr	Manual	Filled	3/22/2015
2/1/2015	Construction Coordinator	Bridgeville PA - Op Ctr	Manual	Filled	3/22/2015
2/1/2015	Construction Coordinator	PA South Construction Mod	Manual	Filled	2/22/2015
2/1/2015	Construction Coordinator	Washington PA-Op Ctr	Manual	Vacant	
2/1/2015	Construction Coordinator	York PA-Op Ctr	Manual	Filled	4/19/2015
2/1/2015	Construction Coordinator	York PA-Op Ctr	Manual	Filled	4/19/2015
3/1/2015	Damage Prevention Coordinator	Bridgeville PA - Op Ctr	Clerical	Vacant	
3/1/2015	Meter Regulator Oper Sr	York PA-Op Ctr	Manual	Vacant	
3/1/2015	M & R Technician Sr	Emlenton PA-Mod Site	Manual	Filled	4/19/2015
3/1/2015	Locator Technician	Uniontown PA-Mod Site	Manual	Filled	3/30/2015
3/1/2015	Laborer-Regular - EL	Rochester PA-Op Ctr	Manual	Vacant	
3/1/2015	Laborer-Regular - EL	Rochester PA-Op Ctr	Manual	Vacant	
3/1/2015	Laborer Regular-EL	Bridgeville PA - Op Ctr	Manual	Vacant	
3/1/2015	Laborer Regular-EL	Bridgeville PA - Op Ctr	Manual	Vacant	
3/1/2015	Laborer Regular-EL	Bridgeville PA - Op Ctr	Manual	Filled	3/30/2015
3/1/2015	Laborer Regular-EL	Bridgeville PA - Op Ctr	Manual	Vacant	
3/1/2015	M & R Technician	Washington PA-Op Ctr	Manual	Vacant	
3/1/2015	Leader Field Operations	New Castle PA-Mod Site	Exempt	Vacant	
5/1/2015	Dir Comm & Community Relations	Canonsburg-SPT PA-Hqtr	Exempt	Filled	5/1/2015

Employees	HTY 11/30/2014	Posted Positions	To be Posted	Filled Positions 12/31/2014	Filled Positions 1/31/2015	Filled Positions 2/28/2015	Filled Positions 3/31/2015	Filled Positions 4/30/2015	Filled Positions 5/31/2015	FTY 11/30/2015
Total Clerical Labor	68	2	0	1	0	0	0	0	0	71
Total Exempt Labor	111	3	0	0	0	0	1	0	1	111
Total Manual - Non-Union	11	1	0	0	0	1	0	0	0	11
Total Manual - Union	390	17	13	0	1	1	4	3	0	423
Total Employees	580	23	13	1	1	2	5	3	1	616

Columbia Gas of Pennsylvania, Inc.
Labor Adjustment
For the Twelve Months Ended December 31, 2016

1	Total Employees as of December 31, 2016			633	(a)
2	Total Labor as of December 31, 2016			$ 53,206,256	(a)
3	Average Labor per Employee as of December 31, 2016 (2 / 1)			$84,054	
4	6 Month Average of Vacancies			38	(b)
5	Labor Adjustment for Vacancies (3 x 4)			$3,194,052	
6	Labor Expense Adjustment for Vacancies (Line 5 X 57.2%)	57.21%	(c)	$1,827,317	
7	Labor Capitalized Adjustment for Vacancies (Line 5 X 42.8%)	42.79%	(c)	$1,366,735	

(a) Ref. GAS-RR-026

(b)

Month Ended	Vacancies	Ref. I&E-RE-43
December 1, 2014	30	
January 1, 2015	32	
February 1, 2015	32	
March 1, 2015	53	
April 1, 2015	39	
May 1, 2015	39	
Average Vacancies	38	

(c)

1	Total Labor Expense as of December 31, 2016	$30,439,299	(a)	57.21%
2	Total Labor Capitalized as of December 31, 2016	$22,766,957	(a)	42.79%
3	Total Labor as of December 31, 2016 (1 + 2)	$53,206,256	(a)	100.0%

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-014:

Reference Columbia Ex. 104, Sch. 1, p. 2, line 5 concerning other employee benefits:

A. Provide a detailed breakdown for the claim amount of $5,090,000 similar to the detailed schedule provided in the 2012 rate case at Docket No. R-2012-2321748, Volume 5, Ex. No. 104, Sch. 2, pp. 11-12.

B. In the response to Part A., make sure to include a breakdown between FPFTY capitalized and expensed amounts of the following:

1. Profit sharing benefits;

2. Stock rewards; and

3. State whether all allocated amounts from the parent company and/or affiliated companies are included in response to Parts A and B above. If not, identify the following:

   a. The account (on Columbia Ex. 104, Sch. 1, p. 2) where such amounts are reflected;

   b. The attributable expense amount for profit sharing benefits;

   c. The attributable capitalized amount for profit sharing benefits;

   d. The attributable expense amount for stock rewards; and

   e. The attributable capitalized amount for stock rewards.

Response:

A. Please see I&E-RE-014 Attachment A.

B. 1. Please see I&E-RE-014 Attachment A.

2. It should be noted that stock rewards do not hit the Other Employee Benefits line.

3. a. Allocated amounts from the parent company are embedded in NCSC – Shared Services on Line 18 of Exhibit 104 Schedule 1.

b. The attributable amount related to profit sharing is $191,703.

c. No amount is capitalized for the corporate allocated portion of profit sharing expenses.

d. The attributable amount related to stock rewards is $1,516,885.

e. No amount is capitalized for the corporate allocated portion of stock rewards.

Cost Element Number	Employees' Insurance Plans & Other	Twelve Months Ended December 31, 2016		
		Gross Costs	Transfers	Net Costs
9041	Medical	5,376,000	(2,300,390)	3,075,610
9042	Dental	332,000	(142,063)	189,937
9043	Group Life	137,000	(58,622)	78,378
9044	Long-Term Disability	348,000	(148,909)	199,091
9045	Emp Assist Program	84,000	(35,944)	48,056
9081	Thrift Plan	2,195,004	(939,242)	1,255,762
9095	Profit Sharing	243,720	-	243,720
	FFRY Total Other Employee Benefits	8,715,724	(3,625,171)	5,090,553

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-064:

Reference Columbia's response to OCA-VII-2 and I&E-RE-63 concerning stock rewards. Columbia's response to OCA-VII-2 states, "Stock awards are included in NCSC – Shared Services for NCSC stock awards billed to the Company (Table OCA-7-002 A below) and Labor for the Company's stock awards (Table OCA-7-002 B)." However, Columbia's response to I&E RE 63 states, "The Company's claim for labor includes no amount for stock rewards." Provide the following:

A. State which statement above is correct;

B. If the response to OCA-VII-2 above is correct, provide the dollar amount of stock rewards included in the Company's claim for labor.

Response:

A. Both statements are correct, as explained in response to Part B

B.

Company Stock Rewards (paid to Columbia Gas of Pennsylvania employees):

Company stock rewards are included in Labor as reported in the Historical Test Year. Table OCA-7-002 B, presents HTY TME 11-30-2014 actual amount of stock rewards of $240,143 and are included in Labor on Exhibit 104, Schedule 1, Page 2, Line 1, Column 1. While the Company has paid stock rewards to its employees, the Company does not budget for stock rewards. Therefore the Company's claim for labor includes no amount for stock rewards as the labor as presented on Exhibit 104, Schedule 1, Page 2, Line 1, Columns 3 and 5 for the FTY and FFRY periods contain no stock rewards.

NCSC Stock Rewards (Paid to NCSC Employees):

The Company's allocated portion of NCSC stock rewards paid to NCSC employees are included within the NCSC – Shared Services O&M information for the HTY, FTY and FFRY periods. Table A, OCA-7-002, presents HTY TME 11/30/2014 actual amount of NCSC stock rewards of $2,322,893 of which $335,175 is for Phantom Stock, which was removed from the HTY (please see Exhibit 4, Schedule 2, Page 16, Line 6). Therefore the HTY as presented on Exhibit 104, Schedule 1, Page 2, Line 18, Column 1 includes the net amount of $1,987,718 for stock rewards.

The budgeted expense for Stock Rewards in the FTY is $1,467,514 and includes $123,495 of Phantom Stock which was removed from the FTY. The budgeted expense in the FFRY is $1,516,885 of which $112,029 is for Phantom Stock. The Phantom Stock amount of $112,029 was removed from the Company's Cost of Service (please see Exhibit 104, Schedule 2, Page 10). Therefore the FTY and FFRY as presented on Exhibit 104, Schedule 1, Page 2, Line 18, Columns 3 and 5 include the net amounts of $1,344,019 and $1,404,856, respectively, for stock rewards.

Summary

The HTY period includes stock awards for CPA employees and an allocated share for NCSC employees. The FTY and FFRY periods include stock awards for NCSC employees only.

The company's revenue requirement includes no amounts for CPA employee stock awards and $1,404,856 for stock awards for NCSC employees.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-049:

Reference Columbia Statement No. 4, p. 12 and Ex. 4, Sch. 2, p. 7, incentive compensation. For the 2014 and the 2015 Performance Years. Provide the following:

A. Copies of all incentive plan documents, including but not limited to those that include the terms and conditions of the plan(s);

B. Identification of each and every incentive plan target and the FPFTY amount expensed/capitalized attributable to each target;

C. A list of all the financial triggers and their specified minimum performance standard to be achieved in order for any incentive amounts to become payable under the incentive plan;

D. The number of the Company's eligible participants;

E. The positions held by the Company's eligible participants for each plan;

F. Copies of a representative Performance Management Worksheet from each eligible position level of the Company, marking the applicable position level on each worksheet provided; and

G. Whether financial goals or triggers must be met before any incentive compensation is paid. If not, identify the portion of FPFTY incentive compensation expensed/capitalized that is paid independent of whether financial goals are met.

Response:

A. Copies of incentive plan documents for 2014 are included in the response to GAS-RR-027. Copies of incentive plan documents for 2015 are attached to this request as I&E-RE-49 Attachment A and Attachment B.

B. For 2014, the incentive plan goals were $1.66 net operating earnings per share for NiSource, $220 million NiSource Gas Distribution business unit net operating earnings, and $397 million NiSource Gas Distribution business unit funds from operations.

   For 2015, the incentive plan goals are $1.75 net operating earnings per share for NiSource, $238 million NiSource Gas Distribution business unit net operating earnings, and $537 million NiSource Gas Distribution business unit funds from operations.

   The incentive included in the FPFTY period is $2,326,000. The portion assigned to expense and included in the claim is $1,735,000 as shown on Exhibit 104, Schedule 1, Page 2, Line 2, Column 7. The difference, or $591,000, reflects the portion assigned to capital. This claim is based on the assumption the incentive plan goals are met at the target payout levels.

C. For 2014, the incentive plan triggers were $1.61 net operating earnings per share for NiSource, $214 million NiSource Gas Distribution business unit net operating earnings, and $287 million NiSource Gas Distribution business unit funds from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.61, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

   For 2015, the incentive plan triggers were $1.70 net operating earnings per share (NOEPS) for NiSource, $232 million NiSource Gas Distribution business unit net operating earnings, and $465 million NiSource Gas Distribution business unit funds from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.70, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

   For exempt employees, the incentive payout opportunity is two-thirds discretionary and one-third non-discretionary. The discretionary portion of the incentive program is based on performance management linked to goals including customer, employee, process/capability, and financial goals for Columbia Gas. Performance management is executed through the annual evaluative process embodied in the Performance Management Worksheet ("PMW").

A Columbia Gas employee's PMW contains annual performance objectives and articulates the means of measuring the employee's progress in relation to the objectives established. Each employee is actively involved in the development of his or her PMW, with input from his or her supervisor, and the employee's progress is reviewed and discussed with the employee periodically throughout the year.

The use of the PMW process to establish goals to measure employees' performance against these goals is important in reinforcing the proper focus on key initiatives and goals designed to improve customer service, improve safety, and reinforce cost containment. Examples of goals included in a PMW include: (1) enhance public safety; (2) enhance emergency response procedures and training; (3) implement emergency response improvements; and (4) meet or exceed safety targets for E&C and contractors.

See the response to subpart F for copies of employee PMWs.

D. For 2014, 584 employees were eligible. For 2015, approximately 616 employees are eligible.

E. See I&E-RE-49 Attachment C for a list of titles of all eligible employees in 2014 and 2015 as of 4/30/15.

F. See I&E-RE-49 Attachments D through H for PMWs. There is one PMW attached to represent each level of the Company.

G. For 2014 and 2015, the trigger for an incentive plan goal must be met in order for a payment for that goal to occur. If the Corporation's NOEPS for the Performance Year is less than the trigger, no amount is payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

Exhibit B

2015 CORPORATE INCENTIVE PLAN
TERMS AND CONDITIONS FOR PARTICIPANTS
WHO ARE NOT COVERED OFFICERS

NiSource Inc.
2010 Omnibus Incentive Plan

1. Background.

Article XI of the NiSource Inc. 2010 Omnibus Incentive Plan (the "Plan") provides that the Committee may grant Cash-Based Awards to Participants under such terms described by the Committee, subject to the terms of the Plan. This document sets forth the terms and conditions of how Cash-Based Awards will be paid for the applicable Performance Period that begins January 1, 2015 and ends December 31, 2015, to the Participants who have not been designated as "Covered Officers" of the Corporation. Any capitalized term that is not defined in this document shall have the meaning assigned to it in the Plan.

2. Eligibility for Participation.

All exempt and non-exempt employees of the Corporation and its affiliates who are active as of 12/31/2015, are eligible to participate in the Cash-Based Awards Program (the "Program") under the Plan, other than:

(i) "Covered Officers",

(ii) employees who have received a last chance letter, final notice letter or equivalent during the Plan year,

(iii) certain exempt employees who participate in other specialized functional incentive plans, and

(iv) interns;

provided however, that the Committee may add additional employees and remove employees in its discretion ("Eligible Employees"). The Committee or the Corporation's Chief Executive Officer may determine which Eligible Employees or groups of Eligible Employees shall actually participate in the Program. The Committee and the Chief Executive Officer generally shall make this determination each calendar year (a "Performance Year"). Such officers and other Eligible Employees chosen to participate in the Program are "Participants." Designation by the Committee or Chief Executive Officer as a Participant in one Performance Year shall not confer on such Participant the right to be a Participant in another Performance Year.

A Participant who terminates his or her employment with the Corporation after the end of the Performance Year, but before the distribution of the incentive payment will be entitled to receive any payment due under this Program. However, any Participant that is terminated "for

Cause" before the distribution of the incentive payment will not be entitled to receive any payment due under this Program. Notwithstanding the foregoing, any Participant who terminates employment with the Employer and their affiliates due to death, disability or retirement during a calendar year will be deemed a Participant on December 31 of such calendar year, and will receive an incentive payment for such year based on his or her Eligible Earnings through the date of termination of employment. For purposes of this Plan, "retirement" means the employee's attainment of age 55 and 10 "years of service" (as "years of service" is defined in the Employer's qualified retirement plan) and "disability" means the employee's disability as defined in the Employer's long-term disability plan subject in each case to the exclusions listed in 2(i)-(iv).

Notwithstanding the previous paragraphs, an employee described above shall be a "Limited Participant" if he or she has received one or more suspensions without pay totaling five days or more during the calendar year. Each Limited Participant will have his or her individual incentive opportunity reduced by at least 50%. Any Participant not covered under the preceding sentences is a "Full Participant."

3. Performance Targets and Cash-Based Award Payouts.

A. Designation of Groups

For incentive purposes, Participants shall participate as a member of one of the following "Groups": (a) NiSource Gas Distribution "NGD" Business Unit, (b) NIPSCO Business Unit, (c) Columbia Pipeline Group "CPG" Business Unit, and (d) Corporate Support. Groups (a), (b), and (c) above may also be referred to as a "Business Unit."

B. Corporation's Financial Trigger

The Corporation's financial trigger is the Corporation's achievement of net operating earnings per share, after accounting for the cost of payments under the Program ("NOEPS"), of $1.70 for the Performance Year. The Corporation shall have full discretion and authority to determine whether this trigger has been achieved and whether any adjustments need to be made in the calculation of NOEPS to reflect any extraordinary events identified in part (G) below. In the event that Columbia Pipeline Group, Inc. and its subsidiaries ("CPG") are spun off from the Corporation before the expiration of the Performance Year, the NOEPS financial trigger shall be adjusted, in the manner deemed appropriate by the Committee, to reflect performance through the date immediately preceding the spinoff. If the Corporation's NOEPS for the Performance Year is less than $1.70, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

C. Group Financial Triggers

Corporate Support

For Participants in Corporate Support, the performance criterion will be NOEPS and Corporate Funds from Operations ("CFFO"). Part (D) identifies the tiers of NOEPS, CFFO and the corresponding payout percentage of Eligible Earnings that will be used to calculate the amount of the Incentive Pool for the Corporate Support Group. Fifty percent (50%) of a Participant's incentive opportunity will be based upon NOEPS and fifty percent (50%) will be based upon CFFO; provided, however, that the incentive payout percentage for Corporate Support will not exceed the highest payout percentage of the three Business Units.

Business Units

For Participants in a Business Unit, the performance criteria will be NOEPS, the Business Unit's Net Operating Earnings ("BUNOE"), and the Business Unit's Funds from Operations ("BFFO"). Part (D) identifies the tiers of NOEPS, BUNOE and BFFO that will be used to calculate the amount of the Incentive Pool for each Business Unit. Twenty-Five percent (25%) of a Participant's incentive opportunity will be based upon NOEPS, thirty-seven and a half (37.5%) will be based upon BUOE, and thirty-seven and a half (37.5%) will be based upon BFFO.

D. Goals and Payout Percentages

This Part (D) identifies the applicable performance goals for the 2015 Performance Year. Notwithstanding any provision of this document to the contrary, if CPG is spun off from the Corporation before the expiration of the Performance Year, the performance goals identified in this Part (D) shall be adjusted, in the manner deemed appropriate by the Committee, to reflect performance through the date immediately preceding the spinoff.

NOEPS Goals

NOEPS	Individual Payout Percentage
$1.80	Stretch %
$1.75	Target %
$1.70	Trigger %

CFFO Goals (millions)

CFFO	Individual Payout Percentage
$1,680M	Stretch %
$1,530M	Target %
$1,380M	Trigger %

Business Unit Goals

NiSource Gas Distribution Business Unit (millions)

BUNOE	Individual Payout Percentage
$250	Stretch %
$238	Target %
$232	Trigger %

BFFO	Individual Payout Percentage
$609	Stretch %
$537	Target %
$465	Trigger %

NIPSCO Business Unit (millions)

BUNOE	Individual Payout Percentage
$213	Stretch %
$200	Target %
$193	Trigger %

BFFO	Individual Payout Percentage
$515	Stretch %
$454	Target %
$393	Trigger %

CPG Business Unit (millions)

BUNOE	Individual Payout Percentage
$294	Stretch %
$284	Target %
$279	Trigger %

BFFO	Individual Payout Percentage
$566	Stretch %
$499	Target %
$432	Trigger %

E. Incentive Pool Creation

The individual incentive opportunity for a Corporate Support Participant shall equal:

(Participant's Eligible Earnings X NOEPS individual payout percentage X 50%)

PLUS

(Participant's Eligible Earnings X CFFO individual payout percentage X 50%)

The individual incentive opportunity for a Business Unit Participant shall equal[1]:

(Participant's Eligible Earnings X Individual Business Unit
Net Operating Earning payout percentage X 37.5%)

PLUS

(Participant's Eligible Earnings X Individual Business Unit
Funds from Operations payout percentage X 37.5%)

PLUS

(Participant's Eligible Earnings X NOEPS individual payout percentage X 25%)

Eligible Earnings consist of the Participant's base earnings for the calendar year. Additionally, Eligible Earnings for Participants who are non-exempt employees also include all shift premiums and overtime pay for the calendar year. Reimbursements for educational assistance, relocation, meals and mileage, as well as incentive payments, stock option gains, and long-term disability payments are not included in Eligible Earnings.

The individual incentive opportunity for each Participant in a Group will be added together, and the sum will equal the Incentive Pool for that Group.

[1] If the Corporation's NOEPS for the Performance Year is less than $1.70 amount shall be payable under the Plan for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

F. Calculation of Bonus

In general, Participants who are non-exempt employees will receive 100% of their individual incentive amount, as calculated under this Program. The amount of the individual incentive opportunity for Participants who are exempt employees generally will be the amount calculated under this Program, divided into two categories:

- Discretionary: 67% of the Participant's individual incentive calculation will be discretionary; the Corporation may increase or decrease this amount based on the Corporation's assessment of the Participant's performance
- Non-discretionary: 33% of the Participant's individual incentive calculation will be fixed.

Notwithstanding the foregoing, the Committee retains the power, authority and discretion to reduce, eliminate, or otherwise modify the amount calculated as payable.

G. Extraordinary Events

For purposes of calculating the amount of Cash-Based Awards, the Committee may adjust the Cash-Based Awards to reflect the following extraordinary and other similar items:

1. Equity issuances;
2. Debt issuances;
3. Discontinued operations;
4. Mergers, acquisitions, and divestitures;
5. Capital expenditures;
6. Asset write-downs;
7. Litigation or claim judgments or settlements;
8. The effect of changes in tax laws, accounting principles, or other laws or provisions affecting reported results;
9. Any spin-off or other corporate reorganization or restructuring programs;
10. Foreign exchange gains and losses;
11. Extraordinary, unusual, or other nonrecurring items as described in U.S. Generally Accepted Accounting Principles or in management's discussion and analysis of financial conditions and results of operations appearing in the Company's consolidated report to the investment community or investor letters;
12. Significant movements in gas prices; and
13. Significant changes in the law.

4. General Timing of Payment.

If payable, the Participant's incentive will be distributed to the Participant, or the Participant's estate in the event of the Participant's death before payment, in cash in a single sum as soon after the end of the applicable Performance Year, as practicable, but no later than March 15 after the end of the Performance Year, in accordance with the Corporation's payroll practices.

5. Notices.

Any notice required or permitted to be given by the Corporation or the Committee pursuant to the Plan shall be deemed given when personally delivered or deposited in the United States mail, registered or certified, postage prepaid, addressed to the Participant, his or her beneficiary, executors, administrators, successors, assigns or transferees, at the last address shown for the Participant on the records of the Corporation or subsequently provided in writing to the Corporation.

6. Miscellaneous Provisions.

1. Nothing contained herein will confer upon any Participant the right to be retained in the service of an Employer or any affiliate thereof nor limit the right of an Employer or any subsidiary thereof to discharge or otherwise deal with any Participant without regard to the existence of the Plan.

2. The provisions of the Plan shall be construed and interpreted according to the laws of the State of Indiana, except as preempted by federal law.

COLUMBUS/1751152v.7

Exhibit A

2015 CASH-BASED AWARDS
TERMS AND CONDITIONS FOR COVERED OFFICERS

NiSource Inc.
2010 Omnibus Incentive Plan

1. Background

Article XI of the Plan provides that the Committee may grant Cash-Based Awards to Participants under such terms described by the Committee, subject to the terms of the Plan. This document sets forth the terms and conditions of how Cash-Based Awards will be paid for the applicable Performance Period that begins January 1, 2015 and ends December 31, 2015, to the designated covered officers of the Corporation including the individuals listed below and any additional executive officer of the Corporation who holds the position held by one of the individuals listed below in Section 4 who is a "Named Executive Officer" within the meaning of the proxy disclosure rules of the Securities and Exchange Commission for the year-ended 2015 ("Covered Officers"). Any capitalized term that is not defined in this document shall have the meaning assigned to it in the Plan.

2. Performance Measure and Performance Target

The Performance Measure for determining Cash-Based Awards is the Corporation's Operating Income. The Performance Target is Operating Income that is greater than $0.00. If this Performance Target is not achieved, no Cash-Based Awards shall be paid.

3. Value of Awards and Creation of Incentive Pool

The total value of Cash-Based Awards paid to Covered Officers may not exceed an amount equal to one percent of the Corporation's Operating Income during the Performance Period. This amount shall represent the Incentive Pool from which Cash-Based Awards may be paid to Covered Officers.

4. Allocation of Incentive Pool

The value of Cash-Based Awards payable to each Covered Officer from the Incentive Pool shall be determined as follows:

Covered Officer	Percent of Incentive Pool
Skaggs	30% of Pool
Hamrock	15% of Pool
Smith	15% of Pool
Stanley	15% of Pool
Hightman	10% of Pool
Kettering	15% of Pool

The Cash-Based Award payable to any Covered Officer who is a Covered Officer because he or she holds the position held by one of the individuals listed above in this Section 4 shall succeed to such individual's percentage of the pool specified above. The Committee shall have no discretion to increase the value of Cash-Based Awards to an amount greater than those percentages specified in the table above.

5. Maximum Awards Payable to Covered Officers

Notwithstanding any provision to the contrary, in no event may the amount of any individual Cash-Based Award, when aggregated with other Cash-Based Awards during a Performance Period, exceed $10 million.

6. Extraordinary Events

For purposes of calculating the amount of Cash-Based Awards payable to a Covered Officer, the Committee shall adjust the Cash-Based Awards to reflect the following extraordinary and other similar items to the extent that they impact Operating Income by more than $50 million individually:

A. Asset write-downs;
B. Litigation or claim judgments or settlements;
C. The effect of changes in tax laws, accounting principles, or other laws or provisions affecting reported results;
D. Any spin-off or other corporate reorganization or restructuring programs;
E. Mergers, acquisitions or divestitures;
F. Foreign exchange gains and losses; and
G. Extraordinary, unusual, or other nonrecurring items as described in U.S. Generally Accepted Accounting Principles or in management's discussion and analysis of financial conditions and results of operations appearing in the Company's consolidated report to the investment community or investor letters.

Consistent with the foregoing, in the event that Columbia Pipeline Group, Inc. and its subsidiaries ("CPG") are spun off from the Corporation after June 30, 2015, and before the expiration of the Performance Period, the Committee shall adjust the Performance Target such that the Performance Target shall apply for the period that begins January 1, 2015, and ends on the date that immediately precedes the spinoff.

7. Discretion to Reduce Amounts Payable

Notwithstanding any provision to the contrary, the Committee shall have the discretion to reduce the amount of Cash-Based Awards payable to Covered Officers. For purposes of exercising such negative discretion, the Committee may be guided by the performance measures (including extraordinary events) as defined and set forth in Exhibit B attached to the resolutions related to the adoption of 2015 Cash-Based Award Performance Targets under the NiSource Inc. 2010 Omnibus Incentive Plan as well as an additional performance measure related to safety as approved by the Committee. The Committee may consider the following weightings for

Corporate Covered Officers: 50% NOEPS, 40% CFFO and 10% Corporate-wide safety and the following weightings for Covered Officers who lead a Business Unit: 25% NOEPS, 20% CFFO, and, with respect to the Business Units they lead, 10% Business Unit safety, 22.5% BUNOE and 22.5% BFFO. The Committee may also consider any other factors in its sole discretion in determining the actual Cash-Based Awards payable to Covered Officers.

COLUMBUS/1751202v.5

Columbia Gas of Pennsylvania, Inc.
Other Employee Benefits Adjustment
For the Twelve Months Ended December 31, 2016

1	Total Employees as of December 31, 2016	633	(a)
2	Total Other Employee Expense as of December 31, 2016	$ 5,090,000	
3	Average Labor per Employee as of December 31, 2016 (2 / 1)	8,041	
4	6 Month Average of Vacancies	38	(a)
5	Other Employee Benefits Adjustment for Vacancies (3 x 4)	$ 305,561	

(a) Ref. I&E Exhibit No. 2, Schedule 4

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-017:

Reference Columbia Statement No. 4, p. 12 and p. 40; and Columbia Ex. 4, Sch. 2, p. 11 concerning injuries and damages. Provide:

A. An electronic version of this exhibit page in executable format with all formulas intact;

B. The source documentation used to obtain both GDP Deflator columns' detail;

C. An explanation why the twelve month period December 2009 through November 2010 reflects an amount of more than double all of the other years shown;

D. An explanation why it is appropriate to reflect the December 2009 through November 2010 data in the historic average computation.

Response:

A. Please refer to I&E-RE-017 Attachment A.

B. Please refer to I&E-RE-017 Attachment B.

C. The twelve month period December 2009 through 2010 includes a workers compensation claim totaling $163,659 in December 2009 and a higher level of general liabilities claims than in the subsequent years. For these reasons this period's total claims are more than double the other years shown.

D. The historic average computation is the same methodology used in prior cases. Dollars related to Injuries & Damages can vary based on circumstances out of the control of the company. Therefore using an historic five year average provides a normalized dollar amount.

Columbia Gas of Pennsylvania, Inc.
Injuries & Damages
For the Twelve Months Ended December 31, 2016

Twelve Month Period		Adjusted Amount per "Injuries & Damages 2010-2014" Column of Co. Ex. 4, Sch. 2, p. 11
12/13-11/14		$ 261,045
12/12-11/13		368,598
12/11-11/12		335,772
I&E Recommended Three-Year Historic Average		321,805
FTY Inflation	1.8385%	5,916
FTY Amount		327,721
FPFTY Inflation	1.8623%	6,103
I&E Recommended Allowance		333,825
Company Claim (per Co. Ex. 104, Sch. 1, p.2)		429,150
I&E Recommended Adjustment		$ (95,325)

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Christopher Keller, hereby state that the facts set forth in the foregoing documents, I&E Statement No. 2 and I&E Exhibit No. 2, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Name

I&E Statement No. 2-R
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Rebuttal Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

RIDER NAS – NEW AREA SERVICE

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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 Financial Analyst.

Q. **ARE YOU THE SAME CHRISTOPHER KELLER WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?**

A. Yes.

Q. **WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Office of Consumer Advocate (OCA) witness Jerome D. Mierzwa (OCA Statement No. 3) regarding Rider NAS service expansion proposals.

Q. **DOES YOUR REBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?**

A. No.

Q. WHAT IS RIDER NAS – NEW AREA SERVICE?

A. Rider NAS is a program by Columbia Gas of Pennsylvania, Inc. (Columbia) to provide an alternative approach to paying deposits for facility extensions in a single lump sum. Prior to Rider NAS, when a prospective customer contacted the Company to inquire about securing gas service in a location not currently served, that customer was responsible for payment of any portion of the extension cost that cannot be justified by projected revenues. This is referred to as the uneconomic portion of the extension. This uneconomic share required the customer to provide an up-front deposit before service will be extended. Rider NAS gives prospective customers the option of paying all or a portion of the uneconomic share through an additional monthly charge payable over a period of 20 years rather than a lump sum payment based on the difference between the net present value (NPV) of the projected future revenue and the costs associated with adding the prospective customer.

Q. WHAT IS OCA WITNESS MIERZWA'S RECOMMENDATION WITH RESPECT TO THE COMPANY'S NPV CALCULATION?

A. In his direct testimony, Mr. Mierzwa suggests that Columbia's NPV calculation be modified to include a five percent annual revenue escalation factor. Mr. Mierzwa opines that Columbia's NPV calculation which includes customer revenue contributions based on current rates is unreasonable because Columbia's base rates will increase over the 40 year period currently included in Columbia's calculation (OCA Statement No. 3, p. 41, lns. 3-10).

Q. DO YOU AGREE WITH MR. MIERZWA'S RECOMMENDATION?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend use of the Company's NPV calculation which is based on current rates, rather than the use of an arbitrary five percent annual revenue escalation factor as proposed by Mr. Mierzwa.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Mr. Mierzwa fails to recognize that, while Columbia's base rates *will* increase over the next 40 years, any future increases in base rates will be the result of additional revenues needed to cover any increases in the specific costs of providing safe and reliable service while providing an adequate return on rate base over that time frame. Therefore, any future increases to base rates will be attributable to future increases to expenses and a return on future additions to rate base and would have no effect on the NPV calculation.

Q. DOES MR. MIERZWA PROVIDE ANY SUPPORT FOR HOW HE DETERMINED THE RECOMMENDED FIVE PERCENT REVENUE ESCALATION FACTOR?

A. No. Mr. Mierzwa arbitrarily recommends the NPV calculation be adjusted to include a five percent annual revenue escalation factor. Mr. Mierzwa provides no support for how he determined the recommended five percent as the appropriate factor. Thus, I recommend the use of the Company's NPV calculation based on current rates rather than adjusting the NPV calculation by an unsupported five percent annual revenue factor proposed by Mr. Mierzwa.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2-R
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Rebuttal Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

RIDER NAS – NEW AREA SERVICE

I&E Stmt. 2-R
R-2015-2468056
8-4-15
Harrisburg

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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 Financial Analyst.

Q. ARE YOU THE SAME CHRISTOPHER KELLER WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?

A. Yes.

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Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

<u>**VERIFICATION**</u>

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Christopher Keller, hereby state that the facts set forth in the foregoing document, I&E Statement No. 2-R, is true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Christopher Keller
Name

I&E Statement No. 2-SR
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Surrebuttal Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES
RATE BASE

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A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or "Company") witnesses Kelley K. Miller (Company Statement No. 104-R), Nicole M. Paloney (Company Statement No. 106-R), Matthew T. Hanson (Company Statement No. 109-R), and Kimberly K. Cartella (Company Statement No. 117-R).

Q. DOES YOUR SURREBUTTAL INCLUDE AN ACCOMPANYING EXHIBIT?

A. No.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING RATE CASE EXPENSE.

A. In direct testimony I recommended rate case expense be normalized over 15 months resulting in an annual expense of $824,000 ($1,030,000 ÷ 15 months x 12 months), or a reduction of $206,000 ($1,030,000 – $824,000) to the Company's annual rate case expense claim. I disagreed with the Company's claimed one-year normalization period which is not supported by the Company's historic filing frequency (I&E Statement No. 2, pp. 3-6).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. Yes. Company witness Kelley K. Miller responded to my recommendation that rate case expense be normalized over a 15-month period. Ms. Miller expressed disagreement with my recommendation stating the Company is now filing annual rate cases and anticipates filing annual rate cases in the future; therefore, she opines that a 12-month normalization period is appropriate (Company Statement No. 104-R, pp. 3-4).

Q. DO YOU AGREE WITH MS. MILLER'S RESPONSE?

A. No. As stated in my direct testimony, the Commission has cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes (I&E Statement No. 2, pp. 3-6). While the Commission allows utilities to normalize this expense, it is not appropriate to do so over a time period that is based on mere speculation of future filings or a simple statement that the Company needs to file rate cases more frequently.

Q. WERE THERE ANY UTILITY COMPANIES THAT HAVE BEEN GRANTED A NORMALIZATION PERIOD BASED ON FUTURE SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation ("PPL") permission to normalize its rate case expense over a twenty-four month period based on the expected timing of future base rate case filings.[1] That particular base rate case was filed on March 30, 2012; however, PPL did not file its next rate case until March 31, 2015, which was thirty-six months after the 2012 rate case filing.

1 Docket No. R-2012-2290597, PA Public Utility Commission Opinion and Order, p. 48.

Hence, the discrepancy between PPL's *intention to file* and its actual filing date of another rate case shows that historic filing frequencies are more reliable than future projections when determining an appropriate normalization period for rate case expense.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend that rate case expenses be normalized over 15 months as the Company's historic filing frequency does not support the 12-month normalization period claimed by the Company. I also continue to recommend that the Company consider using its DSIC tariff to increase the lag between rate case filings if the Company's continued accelerated pipeline investment is such that it plans to file annual base rate cases. This will alleviate the impact of annual filings on ratepayers while ensuring safety through pipeline investment (I&E Statement No. 2, pp. 3-6).

<u>**LABOR AND RELATED TAXES**</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING LABOR AND RELATED TAXES.

A. In direct testimony, I recommended an allowance for labor expense of $28,611,982, or a reduction of $1,827,317 ($30,439,299 - $28,611,982).

Furthermore, I recommended an allowance of $21,400,222 for capitalized labor, or a reduction of $1,366,735.

I also recommended a corresponding reduction to FICA tax expense of $132,523 and a reduction to capitalized FICA taxes of $99,120. My recommendations were based on a six-month average of vacancies (from December 1, 2014 through May 1, 2015) multiplied by the average dollar amount associated with normal staff vacancies and employee turnover (I&E Statement No. 2, pp. 6-11).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATIONS FOR LABOR AND RELATED TAXES?

A. Yes. Company witnesses Matthew T. Hanson and Nicole M. Paloney responded to my recommendations for labor expense and related taxes. Mr. Hanson stated that while the Company does carry some level of vacancies, this does not have an impact on the amount of expense incurred, and that the amount claimed by the Company for labor represents the amount expected to complete the Company's full operational work plan for the year. Mr. Hanson further stated that even if there are vacancies, the work still is completed either through overtime or by hiring external contractors which would result in being over budget for outside services and under budget for labor. In short, he states that vacancies are already inherently factored into the budgeting process (Company Statement 109-R, pp. 5-6).

Ms. Paloney argued that the capital work plan is not impacted by vacancies and she also argued that labor expense is not impacted by the level of vacancies, because these labor dollars would be incurred either way via overtime or outside contractors. She further disagreed with the breakdown of my adjustment between capitalized and expensed portions because the Company has historically met its capital spend projections (Company Statement 106-R, pp. 7-9).

Q. DO YOU AGREE WITH MR. HANSON'S RESPONSE THAT THE VACANCY RATE DOES NOT IMPACT THE TOTAL AMOUNT OF EXPENSES INCURRED?

A. No. As I stated in my direct testimony, and contrary to Mr. Hanson's statement, the Company's labor claim is reflective of full staffing of all budgeted positions and while this is ideal, this is not the reality. I also noted in my testimony that the Company has yet to provide all of the requested monthly vacancy levels (I&E Statement No. 2, pp. 11-13). Furthermore, in the Company's response to Standard Data Request GAS-RR-021, the Company states,

> Routine or normal position vacancies were not considered in the budgeted labor projections. Positions left open through retirement and/or terminations are filled with employees at wages equal to the wage of the exiting employee. The budget anticipates that any short term vacancies will be covered through *increases in overtime or outside labor*" (emphasis added).

According to the Company's response to Standard Data Request GAS-RR-026, the Company is already accounting for vacancies through its request for an increase to overtime payroll by 19.6% [(($3,587,804 + $2,683,485) – ($3,011,518 + $2,231,030)) ÷ ($3,011,518 + $2,231,030)].

Mr. Hanson's argument that any vacancy adjustment would result in a corresponding increase in outside services and overtime claims presumes that the Company addresses all employee resignations or retirements by immediately contracting temporary employees or immediately starting overtime for current employees. Immediately putting outside contractors in place for any normal turnover vacancy or immediately implement overtime is exceptionally unlikely. Additionally, it is unlikely and unsupported that the cost of replacing an employee through overtime or outside contractors would cost the same as replacing the employee.

Furthermore, the Company's argument that vacant positions automatically increase outside contract work is an argument for which its witnesses have not provided adequate supporting details to show how this difference is not already included in the Company's overtime and/or outside services ratemaking claims.

Q. DO YOU AGREE WITH MS. PALONEY'S RESPONSE IN REBUTTAL TESTIMONY THAT THE CAPITAL WORK PLAN IS NOT IMPACTED BY VACANCIES?

A. No. Ms. Paloney argued that labor expense for vacancies not filled does not imply that these labor dollars would not be incurred through overtime or outside contractors. As I explained above, the Company has already taken this into account through the requested increase in overtime payroll, and the Company has not provided adequate assurance that its outside services claim of $2.2 million does not already include a related increase due to employee vacancies. Additionally, the Company has not shown how it would be able to immediately put outside contractors in place for any normal turnover vacancy.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR LABOR AND RELATED TAXES?

A. No. I continue to recommend a reduction to the Company's claim based on a six-month average of vacancies multiplied by the average dollars associated with normal staff vacancies and employee turnover as it is reasonable to consider an average vacancy level associated with normal employee turnover, much of which would likely be covered by existing employees picking up the workload of vacant position. Some of those employees would be eligible for overtime pay and some would be exempt, depending on the position. The Company has contradicted itself on whether vacancies are or are not included in its labor claim and the Company not shown how coverage of vacancy with overtime is not already claimed in overtime and or outside service claims.

NCSC – SHARED SERVICES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR NCSC SHARED SERVICES.

A. In direct testimony, I recommended that NCSC – Shared Services be reduced to \$30,049,731, or a reduction of \$1,596,559 (\$31,646,290 - \$30,049,731) to the Company's claim. Ratepayers should not be obligated to pay for a benefit that is only available to top-level employees of NiSource and its affiliates, that is based solely on earnings goals, and is unrelated to the provision of safe and reliable service (I&E Statement No. 2, pp. 11-13).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR NCSC – SHARED SERVICES?

A. Yes. Company witness Kimberly K. Cartella (Company Statement No. 117-R) responded by stating that profit sharing is an element of the Company's retirement savings plan and if the Company did not make these contributions, the it would need to make other adjustments to its total rewards package, such as increases to base pay or 401(k) contributions to remain competitive in the market for quality employees. Ms. Cartella further stated that stock rewards are a common element of compensation at certain levels of organizations throughout the U.S. and should be allowed (Company Statement No. 117-R, pp. 2-5).

Q. DO YOU AGREE WITH MS. CARTELLA'S RESPONSE THAT THE COMPANY WOULD NEED TO MAKE OTHER ADJUSTMENTS TO ITS TOTAL REWARDS PACKAGE?

A. No. I am not recommending the Company to eliminate the benefit. I am recommending that ratepayers should not be required to fund it as they are not the beneficiaries of top executives meeting earnings goals. As I stated in my direct testimony, profit sharing is based solely on NiSource meeting it's earning per share goal and is made independent of quality of service, efficiency, or safety goals of Columbia Gas (I&E Statement No. 2, pp. 11-13).

Q. DO YOU AGREE WITH MS. CARTELLA'S RESPONSE THAT STOCK REWARDS ARE A COMMON ELEMENT OF COMPENSATION AT CERTAIN LEVELS OF ORGANIZATIONS THROUGHOUT THE U.S. AND SHOULD BE ALLOWED?

A. No. As I stated in my direct testimony, stock rewards are only available to top level NiSource employees and its affiliates and the ratepayers should not be obligated to pay for an expenses that is unrelated to providing safe and reliable service (I&E Statement No. 2, pp. 11-13). Furthermore, in the Company's response to Standard Data Request GAS-RR-027, Attachment B, page 4, which describes the stock rewards program under "What is the Plan's purpose?" it specifically states, "The Plan is designed to promote the achievement of both our short-term and long-term objectives by aligning compensation of participants with the *interests of our stockholders*" (emphasis added). Therefore, while stock rewards may be commonly offered executives, the cost of such of a plan should be paid for by the shareholders and not the ratepayer as stock rewards are clearly in the best interests of shareholders.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR NCSC – SHARED SERVICES?

A. No. I continue to recommend that the amounts attributable to profit sharing and stock rewards be disallowed as ratepayers should not be obligated to pay for an expense that is based solely on earnings goals and is in the best interest of shareholders and not ratepayers. The fact that this expense is unrelated to the provision of safe and reliable service is undisputed by Ms. Cartella.

<u>OTHER EMPLOYEE BENEFITS</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING OTHER EMPLOYEE BENEFITS.

A. In direct testimony, I recommended that other employee benefits be reduced to an annual amount of $4,784,436, or a reduction of $305,561 ($5,090,000 - $4,784,439) to the Company's claim. My recommendation was based on my prior adjustment to labor for vacancies (I&E Statement No. 2, pp. 13-14).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS?

A. Yes. Company witness Matthew T. Hanson responded to my recommendation that other employee benefits be reduced by $305,561. Mr. Hanson stated that while the Company does carry some level of vacancies, this does not have an impact on the amount of expense incurred by the Company and that the amount claimed by the Company for labor represents the amount expected to complete the Company's full operational work plan for the year. Mr. Hanson further stated that even if there are vacancies, the work still is completed either through overtime or by hiring external contractors which would result in the Company being over budget for outside services and under budget for labor (Company Statement 109-R, pp. 5-6).

Q. DO YOU AGREE WITH MR. HANSON'S RESPONSE THAT THE AMOUNT OF VACANCIES DOES NOT HAVE AN IMPACT ON THE AMOUNT OF THE EXPENSE INCURRED BY THE COMPANY, AND THAT THE WORK STILL NEEDS TO BE COMPLETED EITHER THROUGH OVERTIME OR EXTERNAL CONTRACTORS?

A. This argument is fully addressed in my Labor and Related Taxes section above. The Company's labor claim is reflective of full staffing of all budgeted positions as it stated in Standard Data Request GAS-RR-021 and while this is ideal, this is not reflective of the level of expense the Company can expect going forward. .

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS?

A. No. I continue to recommend a reduction to the Company's claim based on my related adjustment to labor.

<u>INJURIES AND DAMAGES</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INJURIES AND DAMAGES.

A. In direct testimony, I recommended that injuries and damages be reduced to an annual amount of $333,825, or a reduction of $95,325 ($429,150 - $333,825) to the Company's claim. My recommendation was based on a three-year historic average for injuries and damages based on the twelve months ended November 30, 2012, November 30, 2013, and November 30, 2014. This three-year average provides a fair and reasonable increase in injuries and damages. This three-year average also eliminates a period where the Company paid out higher claim amounts than it has experienced in most recent years, i.e., the twelve months ended (TME) November 30, 2010 included a workers' compensation claim of $163,659 in December 2009 and a higher level of general liabilities than in subsequent years (I&E Statement No. 2, pp. 14-16).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR INJURIES AND DAMAGES?

A. Yes. Company witness Kimberly K. Miller responded to my recommendation that injuries and damages be reduced to $333,825 by stating that I arbitrarily selected a three-year average to produce a lower result, and that the Company has consistently used a five-year average for injuries and damages (Company Statement No. 104-R, pp. 4-5).

Q. DO YOU HAVE ANY RESPONSE TO MS. MILLER RESPONSE THAT YOU ARBITRARILY CHOSE A THREE-YEAR AVERAGE TO PRODUCE A LOWER RESULT?

A. Yes. My recommendation, through the use of a three-year historical average, more accurately represents the Company's current costs for injuries and damages as the trend in this expense is downward. As I stated in my direct testimony, the Company acknowledged that the amount for injuries and damages for the TME November 30, 2010 is abnormally higher than subsequent years due to a workers' compensation claim totaling $163,659 in December 2009 and a higher level of general liabilities. Therefore, using a three-year average is more appropriate in determining the amount for the FPFTY for injuries and damages instead of a five-year average (I&E Statement No. 2, pp. 14-16).

Q. DO YOU HAVE ANY RESPONSE TO MS. MILLER'S RESPONSE THAT THE COMPANY HAS CONSISTENTLY USED A FIVE-YEAR AVERAGE FOR INJURIES AND DAMAGES?

A. Yes. While the Company has in fact used a five-year average in prior filings, Company Exhibit. 4, Sch. 2, p. 11 clearly shows that the amount for the TME November 30, 2010 of $777,789 does not accurately reflect what the Company has experienced in recent years when compared to the four subsequent years, which range from $261,045 to $368,598.

Year	Injuries and Damages
December 2013 – November 2014	$261,045
December 2012 – November 2013	$368,598
December 2011 – November 2012	$335,772
December 2010 – November 2011	$325,288
December 2009 – November 2010	$777,789

While historic numbers and methodologies are helpful in determining an appropriate expense level they are not absolute. The reasonable expectation of an expense level in the future is the best guidance. Ms. Miller's absolute reliance on previously used methodologies in light of different recent information is arbitrary and self-serving.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR INJURIES AND DAMAGES?

A. No. I continue to recommend the use of a three year average for injuries and damages as this is fair and reasonable and provides a more accurate estimate of expenses to be incurred going forward.

SUMMARY OF I&E'S UPDATED POSITION

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my recommended adjustments.

	Company Claim	I&E Adjustment	I&E Recommended Allowance
O&M Expenses:			
Rate Case Expense	$1,030,000	($206,000)	$824,000
Labor	$30,439,299	($1,827,317)	$28,611,982
FICA Tax		($132,523)	
NCSC – Shared Services	$31,646,290	($1,596,559)	$30,049,731
Other Employee Benefits	$5,090,000	($305,561)	$4,784,439
Injuries & Damages	$429,150	($95,325)	$333,825
Total O&M Expense Adjustments		($4,163,285)	

	Company Claim	I&E Adjustment	I&E Recommended Allowance
Rate Base Adjustments:			
Capitalized Labor	$22,766,957	($1,366,735)	$21,400,222
Capitalized FICA Tax		($99,120)	
Total Rate Base Adjustments		($1,465,855)	

Q. WHAT IS I&E'S TOTAL UPDATED REVENUE REQUIREMENT RECOMMENDATION?

A. I&E's total recommended revenue requirement for the Company is $560,556,790. This recommended revenue requirement represents an increase of $17,464,175 to the I&E adjusted present rate revenues of $543,092,615. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimonies of I&E Witnesses Maurer (I&E St. No. 1-SR) and Hubert (I&E St. No. 3-SR).

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY REBUTTAL?

A. Yes, I understand that on July 8, 2015 the Commission entered an Order regarding the Company's Universal Service and Energy Conservation Plan at Docket No. M-2014-2424462. Among other things this Order directed that relevant parties should address the issue of funding the Hardship fund through a means other than the Rider USP. The Company did not address the Commission's directive in its rebuttal testimony.

Q. WHY IS THE COMMISSION CONCERNED WITH HARDSHIP FUNDING THROUGH THE RIDER USP?

A. The Commission stated in its Order that

> With the exception of PGW,[2] we are not aware of any other utility that collects hardship fund grant funds – partially or in-full – by billing non-CAP residential customers. Hardship Fund grants are traditionally and primarily funded through voluntary contributions (*i.e.*, from employees, customers, fund raising efforts, etc.), matching funds from the company, and shareholder/company non-recoverable contributions. Some utilities do recover the costs associated with Hardship Fund administration from non-CAP residential customers, but not for eligible customer grant amounts. We are concerned that Columbia may have placed too much reliance on funding its Hardship Fund from sources other than direct donations from shareholders, employees, customers, and other convened entities.[3]

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[2] PGW is a city-owned utility and is funded by taxpayer dollars. Therefore, contributions by PGW to its Hardship Fund program are recovered via base rates.

[3] Order Entered July 8, 2015, Docket No. M-2014-2424462, page 38

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Company follow the Commission directive, and fund the Hardship fund through voluntary donations and not mandatory contribution via the Rider USP.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2-SR
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

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Q. **ARE YOU THE SAME CHRISTOPHER KELLER WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?**

A. Yes.

Q. **WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or "Company") witnesses Kelley K. Miller (Company Statement No. 104-R), Nicole M. Paloney (Company Statement No. 106-R), Matthew T. Hanson (Company Statement No. 109-R), and Kimberly K. Cartella (Company Statement No. 117-R).

Q. DOES YOUR SURREBUTTAL INCLUDE AN ACCOMPANYING EXHIBIT?

A. No.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING RATE CASE EXPENSE.

A. In direct testimony I recommended rate case expense be normalized over 15 months resulting in an annual expense of $824,000 ($1,030,000 ÷ 15 months x 12 months), or a reduction of $206,000 ($1,030,000 – $824,000) to the Company's annual rate case expense claim. I disagreed with the Company's claimed one-year normalization period which is not supported by the Company's historic filing frequency (I&E Statement No. 2, pp. 3-6).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. Yes. Company witness Kelley K. Miller responded to my recommendation that rate case expense be normalized over a 15-month period. Ms. Miller expressed disagreement with my recommendation stating the Company is now filing annual rate cases and anticipates filing annual rate cases in the future; therefore, she opines that a 12-month normalization period is appropriate (Company Statement No. 104-R, pp. 3-4).

Q. DO YOU AGREE WITH MS. MILLER'S RESPONSE?

A. No. As stated in my direct testimony, the Commission has cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes (I&E Statement No. 2, pp. 3-6). While the Commission allows utilities to normalize this expense, it is not appropriate to do so over a time period that is based on mere speculation of future filings or a simple statement that the Company needs to file rate cases more frequently.

Q. WERE THERE ANY UTILITY COMPANIES THAT HAVE BEEN GRANTED A NORMALIZATION PERIOD BASED ON FUTURE SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation ("PPL") permission to normalize its rate case expense over a twenty-four month period based on the expected timing of future base rate case filings.[1] That particular base rate case was filed on March 30, 2012; however, PPL did not file its next rate case until March 31, 2015, which was thirty-six months after the 2012 rate case filing.

1 Docket No. R-2012-2290597, PA Public Utility Commission Opinion and Order, p. 48.

Hence, the discrepancy between PPL's *intention to file* and its actual filing date of another rate case shows that historic filing frequencies are more reliable than future projections when determining an appropriate normalization period for rate case expense.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend that rate case expenses be normalized over 15 months as the Company's historic filing frequency does not support the 12-month normalization period claimed by the Company. I also continue to recommend that the Company consider using its DSIC tariff to increase the lag between rate case filings if the Company's continued accelerated pipeline investment is such that it plans to file annual base rate cases. This will alleviate the impact of annual filings on ratepayers while ensuring safety through pipeline investment (I&E Statement No. 2, pp. 3-6).

LABOR AND RELATED TAXES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING LABOR AND RELATED TAXES.

A. In direct testimony, I recommended an allowance for labor expense of $28,611,982, or a reduction of $1,827,317 ($30,439,299 - $28,611,982).

Furthermore, I recommended an allowance of $21,400,222 for capitalized labor, or a reduction of $1,366,735.

I also recommended a corresponding reduction to FICA tax expense of $132,523 and a reduction to capitalized FICA taxes of $99,120. My recommendations were based on a six-month average of vacancies (from December 1, 2014 through May 1, 2015) multiplied by the average dollar amount associated with normal staff vacancies and employee turnover (I&E Statement No. 2, pp. 6-11).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATIONS FOR LABOR AND RELATED TAXES?

A. Yes. Company witnesses Matthew T. Hanson and Nicole M. Paloney responded to my recommendations for labor expense and related taxes. Mr. Hanson stated that while the Company does carry some level of vacancies, this does not have an impact on the amount of expense incurred, and that the amount claimed by the Company for labor represents the amount expected to complete the Company's full operational work plan for the year. Mr. Hanson further stated that even if there are vacancies, the work still is completed either through overtime or by hiring external contractors which would result in being over budget for outside services and under budget for labor. In short, he states that vacancies are already inherently factored into the budgeting process (Company Statement 109-R, pp. 5-6).

Ms. Paloney argued that the capital work plan is not impacted by vacancies and she also argued that labor expense is not impacted by the level of vacancies, because these labor dollars would be incurred either way via overtime or outside contractors. She further disagreed with the breakdown of my adjustment between capitalized and expensed portions because the Company has historically met its capital spend projections (Company Statement 106-R, pp. 7-9).

Q. DO YOU AGREE WITH MR. HANSON'S RESPONSE THAT THE VACANCY RATE DOES NOT IMPACT THE TOTAL AMOUNT OF EXPENSES INCURRED?

A. No. As I stated in my direct testimony, and contrary to Mr. Hanson's statement, the Company's labor claim is reflective of full staffing of all budgeted positions and while this is ideal, this is not the reality. I also noted in my testimony that the Company has yet to provide all of the requested monthly vacancy levels (I&E Statement No. 2, pp. 11-13). Furthermore, in the Company's response to Standard Data Request GAS-RR-021, the Company states,

> Routine or normal position vacancies were not considered in the budgeted labor projections. Positions left open through retirement and/or terminations are filled with employees at wages equal to the wage of the exiting employee. The budget anticipates that any short term vacancies will be covered through *increases in overtime or outside labor*" (emphasis added).

According to the Company's response to Standard Data Request GAS-RR-026, the Company is already accounting for vacancies through its request for an increase to overtime payroll by 19.6% [(($3,587,804 + $2,683,485) – ($3,011,518 + $2,231,030)) ÷ ($3,011,518 + $2,231,030)].

Mr. Hanson's argument that any vacancy adjustment would result in a corresponding increase in outside services and overtime claims presumes that the Company addresses all employee resignations or retirements by immediately contracting temporary employees or immediately starting overtime for current employees. Immediately putting outside contractors in place for any normal turnover vacancy or immediately implement overtime is exceptionally unlikely. Additionally, it is unlikely and unsupported that the cost of replacing an employee through overtime or outside contractors would cost the same as replacing the employee.

Furthermore, the Company's argument that vacant positions automatically increase outside contract work is an argument for which its witnesses have not provided adequate supporting details to show how this difference is not already included in the Company's overtime and/or outside services ratemaking claims.

Q. DO YOU AGREE WITH MS. PALONEY'S RESPONSE IN REBUTTAL TESTIMONY THAT THE CAPITAL WORK PLAN IS NOT IMPACTED BY VACANCIES?

A. No. Ms. Paloney argued that labor expense for vacancies not filled does not imply that these labor dollars would not be incurred through overtime or outside contractors. As I explained above, the Company has already taken this into account through the requested increase in overtime payroll, and the Company has not provided adequate assurance that its outside services claim of $2.2 million does not already include a related increase due to employee vacancies. Additionally, the Company has not shown how it would be able to immediately put outside contractors in place for any normal turnover vacancy.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR LABOR AND RELATED TAXES?

A. No. I continue to recommend a reduction to the Company's claim based on a six-month average of vacancies multiplied by the average dollars associated with normal staff vacancies and employee turnover as it is reasonable to consider an average vacancy level associated with normal employee turnover, much of which would likely be covered by existing employees picking up the workload of vacant position. Some of those employees would be eligible for overtime pay and some would be exempt, depending on the position. The Company has contradicted itself on whether vacancies are or are not included in its labor claim and the Company not shown how coverage of vacancy with overtime is not already claimed in overtime and or outside service claims.

NCSC – SHARED SERVICES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR NCSC SHARED SERVICES.

A. In direct testimony, I recommended that NCSC – Shared Services be reduced to $30,049,731, or a reduction of $1,596,559 ($31,646,290 - $30,049,731) to the Company's claim. Ratepayers should not be obligated to pay for a benefit that is only available to top-level employees of NiSource and its affiliates, that is based solely on earnings goals, and is unrelated to the provision of safe and reliable service (I&E Statement No. 2, pp. 11-13).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR NCSC – SHARED SERVICES?

A. Yes. Company witness Kimberly K. Cartella (Company Statement No. 117-R) responded by stating that profit sharing is an element of the Company's retirement savings plan and if the Company did not make these contributions, the it would need to make other adjustments to its total rewards package, such as increases to base pay or 401(k) contributions to remain competitive in the market for quality employees. Ms. Cartella further stated that stock rewards are a common element of compensation at certain levels of organizations throughout the U.S. and should be allowed (Company Statement No. 117-R, pp. 2-5).

Q. DO YOU AGREE WITH MS. CARTELLA'S RESPONSE THAT THE COMPANY WOULD NEED TO MAKE OTHER ADJUSTMENTS TO ITS TOTAL REWARDS PACKAGE?

A. No. I am not recommending the Company to eliminate the benefit. I am recommending that ratepayers should not be required to fund it as they are not the beneficiaries of top executives meeting earnings goals. As I stated in my direct testimony, profit sharing is based solely on NiSource meeting it's earning per share goal and is made independent of quality of service, efficiency, or safety goals of Columbia Gas (I&E Statement No. 2, pp. 11-13).

Q. DO YOU AGREE WITH MS. CARTELLA'S RESPONSE THAT STOCK REWARDS ARE A COMMON ELEMENT OF COMPENSATION AT CERTAIN LEVELS OF ORGANIZATIONS THROUGHOUT THE U.S. AND SHOULD BE ALLOWED?

A. No. As I stated in my direct testimony, stock rewards are only available to top level NiSource employees and its affiliates and the ratepayers should not be obligated to pay for an expenses that is unrelated to providing safe and reliable service (I&E Statement No. 2, pp. 11-13). Furthermore, in the Company's response to Standard Data Request GAS-RR-027, Attachment B, page 4, which describes the stock rewards program under "What is the Plan's purpose?" it specifically states, "The Plan is designed to promote the achievement of both our short-term and long-term objectives by aligning compensation of participants with the *interests of our stockholders*" (emphasis added). Therefore, while stock rewards may be commonly offered executives, the cost of such of a plan should be paid for by the shareholders and not the ratepayer as stock rewards are clearly in the best interests of shareholders.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR NCSC – SHARED SERVICES?

A. No. I continue to recommend that the amounts attributable to profit sharing and stock rewards be disallowed as ratepayers should not be obligated to pay for an expense that is based solely on earnings goals and is in the best interest of shareholders and not ratepayers. The fact that this expense is unrelated to the provision of safe and reliable service is undisputed by Ms. Cartella.

OTHER EMPLOYEE BENEFITS

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING OTHER EMPLOYEE BENEFITS.

A. In direct testimony, I recommended that other employee benefits be reduced to an annual amount of $4,784,436, or a reduction of $305,561 ($5,090,000 - $4,784,439) to the Company's claim. My recommendation was based on my prior adjustment to labor for vacancies (I&E Statement No. 2, pp. 13-14).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS?

A. Yes. Company witness Matthew T. Hanson responded to my recommendation that other employee benefits be reduced by $305,561. Mr. Hanson stated that while the Company does carry some level of vacancies, this does not have an impact on the amount of expense incurred by the Company and that the amount claimed by the Company for labor represents the amount expected to complete the Company's full operational work plan for the year. Mr. Hanson further stated that even if there are vacancies, the work still is completed either through overtime or by hiring external contractors which would result in the Company being over budget for outside services and under budget for labor (Company Statement 109-R, pp. 5-6).

Q. DO YOU AGREE WITH MR. HANSON'S RESPONSE THAT THE AMOUNT OF VACANCIES DOES NOT HAVE AN IMPACT ON THE AMOUNT OF THE EXPENSE INCURRED BY THE COMPANY, AND THAT THE WORK STILL NEEDS TO BE COMPLETED EITHER THROUGH OVERTIME OR EXTERNAL CONTRACTORS?

A. This argument is fully addressed in my Labor and Related Taxes section above. The Company's labor claim is reflective of full staffing of all budgeted positions as it stated in Standard Data Request GAS-RR-021 and while this is ideal, this is not reflective of the level of expense the Company can expect going forward. .

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS?

A. No. I continue to recommend a reduction to the Company's claim based on my related adjustment to labor.

<u>INJURIES AND DAMAGES</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INJURIES AND DAMAGES.

A. In direct testimony, I recommended that injuries and damages be reduced to an annual amount of $333,825, or a reduction of $95,325 ($429,150 - $333,825) to the Company's claim. My recommendation was based on a three-year historic average for injuries and damages based on the twelve months ended November 30, 2012, November 30, 2013, and November 30, 2014. This three-year average provides a fair and reasonable increase in injuries and damages. This three-year average also eliminates a period where the Company paid out higher claim amounts than it has experienced in most recent years, i.e., the twelve months ended (TME) November 30, 2010 included a workers' compensation claim of $163,659 in December 2009 and a higher level of general liabilities than in subsequent years (I&E Statement No. 2, pp. 14-16).

Q. DID ANY COMPANY WITNESS SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR INJURIES AND DAMAGES?

A. Yes. Company witness Kimberly K. Miller responded to my recommendation that injuries and damages be reduced to $333,825 by stating that I arbitrarily selected a three-year average to produce a lower result, and that the Company has consistently used a five-year average for injuries and damages (Company Statement No. 104-R, pp. 4-5).

Q. DO YOU HAVE ANY RESPONSE TO MS. MILLER RESPONSE THAT YOU ARBITRARILY CHOSE A THREE-YEAR AVERAGE TO PRODUCE A LOWER RESULT?

A. Yes. My recommendation, through the use of a three-year historical average, more accurately represents the Company's current costs for injuries and damages as the trend in this expense is downward. As I stated in my direct testimony, the Company acknowledged that the amount for injuries and damages for the TME November 30, 2010 is abnormally higher than subsequent years due to a workers' compensation claim totaling $163,659 in December 2009 and a higher level of general liabilities. Therefore, using a three-year average is more appropriate in determining the amount for the FPFTY for injuries and damages instead of a five-year average (I&E Statement No. 2, pp. 14-16).

Q. DO YOU HAVE ANY RESPONSE TO MS. MILLER'S RESPONSE THAT THE COMPANY HAS CONSISTENTLY USED A FIVE-YEAR AVERAGE FOR INJURIES AND DAMAGES?

A. Yes. While the Company has in fact used a five-year average in prior filings, Company Exhibit. 4, Sch. 2, p. 11 clearly shows that the amount for the TME November 30, 2010 of $777,789 does not accurately reflect what the Company has experienced in recent years when compared to the four subsequent years, which range from $261,045 to $368,598.

Year	Injuries and Damages
December 2013 – November 2014	$261,045
December 2012 – November 2013	$368,598
December 2011 – November 2012	$335,772
December 2010 – November 2011	$325,288
December 2009 – November 2010	$777,789

While historic numbers and methodologies are helpful in determining an appropriate expense level they are not absolute. The reasonable expectation of an expense level in the future is the best guidance. Ms. Miller's absolute reliance on previously used methodologies in light of different recent information is arbitrary and self-serving.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR INJURIES AND DAMAGES?

A. No. I continue to recommend the use of a three year average for injuries and damages as this is fair and reasonable and provides a more accurate estimate of expenses to be incurred going forward.

SUMMARY OF I&E'S UPDATED POSITION

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my recommended adjustments.

	Company Claim	I&E Adjustment	I&E Recommended Allowance
O&M Expenses:			
Rate Case Expense	$1,030,000	($206,000)	$824,000
Labor	$30,439,299	($1,827,317)	$28,611,982
FICA Tax		($132,523)	
NCSC – Shared Services	$31,646,290	($1,596,559)	$30,049,731
Other Employee Benefits	$5,090,000	($305,561)	$4,784,439
Injuries & Damages	$429,150	($95,325)	$333,825
Total O&M Expense Adjustments		($4,163,285)	

	Company Claim	I&E Adjustment	I&E Recommended Allowance
Rate Base Adjustments:			
Capitalized Labor	$22,766,957	($1,366,735)	$21,400,222
Capitalized FICA Tax		($99,120)	
Total Rate Base Adjustments		($1,465,855)	

Q. WHAT IS I&E'S TOTAL UPDATED REVENUE REQUIREMENT RECOMMENDATION?

A. I&E's total recommended revenue requirement for the Company is $560,556,790. This recommended revenue requirement represents an increase of $17,464,175 to the I&E adjusted present rate revenues of $543,092,615. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimonies of I&E Witnesses Maurer (I&E St. No. 1-SR) and Hubert (I&E St. No. 3-SR).

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY REBUTTAL?

A. Yes, I understand that on July 8, 2015 the Commission entered an Order regarding the Company's Universal Service and Energy Conservation Plan at Docket No. M-2014-2424462. Among other things this Order directed that relevant parties should address the issue of funding the Hardship fund through a means other than the Rider USP. The Company did not address the Commission's directive in its rebuttal testimony.

Q. WHY IS THE COMMISSION CONCERNED WITH HARDSHIP FUNDING THROUGH THE RIDER USP?

A. The Commission stated in its Order that

> With the exception of PGW,[2] we are not aware of any other utility that collects hardship fund grant funds – partially or in-full – by billing non-CAP residential customers. Hardship Fund grants are traditionally and primarily funded through voluntary contributions (*i.e.*, from employees, customers, fund raising efforts, etc.), matching funds from the company, and shareholder/company non-recoverable contributions. Some utilities do recover the costs associated with Hardship Fund administration from non-CAP residential customers, but not for eligible customer grant amounts. We are concerned that Columbia may have placed too much reliance on funding its Hardship Fund from sources other than direct donations from shareholders, employees, customers, and other convened entities.[3]

[2] PGW is a city-owned utility and is funded by taxpayer dollars. Therefore, contributions by PGW to its Hardship Fund program are recovered via base rates.
[3] Order Entered July 8, 2015, Docket No. M-2014-2424462, page 38

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Company follow the Commission directive, and fund the Hardship fund through voluntary donations and not mandatory contribution via the Rider USP.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Christopher Keller, hereby state that the facts set forth in the foregoing document, I&E Statement No. 2-SR, is true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Christopher Keller
Name

I&E Statement No. 3
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Direct Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Test Year
Rate Base
Present Rate Revenues
Cost of Service
Scaleback
Customer Cost Analysis
Customer Charges
CAC Rider

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy B. Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

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 EMPLOYMENT EXPERIENCE?

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

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

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT ISSUES DO YOU ADDRESS IN YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") requested $46,171,228 overall revenue increase, comprised of a base rate revenue increase of $43,788,431, as well as increases related to the Rider

Customer Choice ("Rider CC"), the Gas Procurement Charge Rider ("Rider GPC"), the Rider Universal Service Plan ("Rider USP"), and the newly proposed Choice Administration Charge Rider ("Rider CAC"). My testimony specifically addresses the following issues:

- Fully Projected Future Test Year ("FPFTY");
- Use of the FPFTY as it applies to Rate Base;
- The effect of projected use per customer on present rate revenues;
- Competitive Discounts;
- Rate Schedule Grouping;
- Use of the most representative cost of service study;
- Manner of scale back;
- Customer Cost Analysis;
- Customer Charges;
- Creation of Rider CAC.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED BY A COMPANY IN A RATE PROCEEDING?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. Previously in rate case proceedings, in order to meet its burden of proof, a utility could only use a historic test year ("HTY") or a future test year ("FTY"). A historic test year is a twelve-month period selected by a company that represents a recent full year of actual data. A future test year begins the day after the historic test year ends and is used in order to allow for the time it takes to adjudicate a rate proceeding by permitting a company to select a future time period upon which to base its financial information. This is necessary so that the rates set by the Commission reflect current and synchronized financial information. By using a future test year, a utility makes a projected annualized and normalized estimate of future revenues and expenses and a corresponding measure of value at the end of the period.

Q. DESCRIBE THE FPFTY.

A. On February 14, 2012, Act 11 of 2012 ("Act 11") was signed into law, which amended Chapters 3, 13 and 33 of the Public Utility Code (Title 66 of the Pennsylvania Consolidated Statues). In particular, Chapter 3 of the Code was amended to provide that utilities may use a FPFTY to attempt to meet their burden of proof in rate cases. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under 66 Pa.C.S. § 1308(d).

Q. COULD YOU ILLUSTRATE HOW ACT 11 IMPACTS THE TEST YEARS?

A. Yes. Using the Company's HTY and FTY, without Act 11 and with the Company having filed its rate case on March 19, 2015, the Company's HTY ended November 30, 2014 and its rates would have been based on the FTY ending November 30, 2015. At the end of the suspension period set by the Commission, the Company's new rates would have been placed into effect on January 1, 2016. With the addition of the FPFTY, however, the Company has the ability to project plant additions, revenues, and expenses out one more year, using as the FPFTY the twelve-month period that begins with the first month that the new rates will be placed into effect, or January 1, 2016 through December 31, 2016.

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. The Company used the twelve-month period ending November 30, 2014 as the historic test year, the twelve-month period ending November 30, 2015 as the future test year, and the twelve-month period ending December 31, 2016 as the fully projected future test year.

Q. AT THIS TIME, HAS THE COMMISSION ADOPTED RULES AND REGULATIONS REGARDING THE USE OF THE FPFTY?

A. No. On August 2, 2012, the Commission entered its Final Implementation Order at Docket No. M-2012-2293611 addressing Act 11 ("*Implementation Order*"). In the *Implementation Order*, the Commission initiated a separate proceeding at Docket No. L-2012-2317273 for the purposes of adopting rules and regulations regarding the use of the FPFTY in accordance with 66 Pa.C.S. § 315 (relating to burden of proof). However, at this time, the proceeding is still pending, and no such regulations have been promulgated.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE PROPER CONSTRUCT OF A FPFTY?

A. Yes. 66 Pa.C.S. Section 315(e) as amended by Act 11 states that the FPFTY shall be the 12-month period beginning with the first month that the new rates will be placed in effect after application of the full suspension period permitted under section 1308(d). Therefore, I believe Columbia has utilized the correct period for its FPFTY.

Q. WHAT TEST YEAR HAS THE COMPANY USED TO CALCULATE ITS REQUESTED REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Although the Commission has not yet developed the procedures and requirements for the use of a FPFTY , the Company selected a FPFTY ending December 31,

2016. As shown on page 7 of the *Implementation Order*, the Commission has shown interest in seeing full documentation to support the methods and assumptions used to develop the FPFTY.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE SELECTED TEST YEAR AND THE CLAIMED REVENUE INCREASE REQUEST IN THIS PROCEEDING?

A. The Company's claimed revenue increase request in this proceeding of $46,171,228 includes the revenue requirement associated with the capital invested prior to the new proposed rates' effective date as well as the capital to be invested during the FPFTY. Under the pre-Act 11 filing rules, only the capital invested prior to the new rate effective date would have been included.

Q. WHAT PORTION OF THE REQUESTED REVENUE INCREASE IS ASSOCIATED SOLELY WITH THE INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2016?

A. The portion of the requested revenue increase associated solely with the inclusion of the FPFTY is approximately $23,791,000. Prior to the authorization of the FPFTY under Act 11, the Company presumably would have filed a revenue requirement of approximately $22,381,000 in this proceeding. The difference between this revenue requirement and the as filed revenue requirement of approximately $46,172,000 reflects the $23,791,000 impact of the FPFTY (I&E Ex. No. 3, Sch. 1).

RATE BASE

Q. WHAT IS MEASURE OF VALUE, ALSO REFERRED TO AS RATE BASE?

A. The measure of value, or rate base, is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS THE DEPRECIATED ORIGINAL COST PLANT IN SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is determined by subtracting the book reserve depreciation, which is the accumulation of all prior annual depreciation expense, and other items such as salvage value from the original cost of the plant in service that is used and useful in the public service. Prior to the passage of Act 11, that calculation would have been performed at a specific point in time that would have been at the end of the FTY. Under the FPFTY in Act 11, the depreciated original cost of the plant in service is now determined by taking a "snapshot" look at the depreciated original cost value of used and useful utility plant estimated to be in service at the end of the FPFTY.

Q. WHAT OTHER ADDITIONS AND DEDUCTIONS TO THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT ARE ALLOWED?

A. Some of the additions to the depreciated original cost of a company's investment in utility include materials and supplies, gas in storage, prepayments, and cash working capital. Some of the deductions include deferred income taxes and customer deposits. Some additions are applicable to a specific utility or utility type. The FPFTY depreciated original cost claimed by Columbia in this proceeding is $1,561,922,944, shown on Columbia Exhibit No. 108, page 3. The claimed additions to the Company's depreciated original cost are as follows:

1. Materials and Supplies;
2. Gas Storage Underground;
3. Prepayments;

The deductions to the depreciated original cost are:

1. Deferred Income Taxes;
2. Customer Deposits;
3. Customer Advances.

Q. HOW IS THE MEASURE OF VALUE USED WITHIN THE RATEMAKING FORMULA?

A. The measure of value is one part of the financial equation used by the Commission, along with allowable expenses and rate of return, to determine the level of income a utility will be granted an opportunity to earn and the revenue level needed to achieve that return. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Measure of Value x Rate of Return) + Allowable Expenses.

Each item in the revenue requirement equation is synchronized to the test year period. If the date of any of the items in this equation is changed, all the other necessary data that a utility must file in a rate proceeding, including the test year income statement, actual and projected customer levels and usage, cost of service study to determine expense responsibility among the various customer classes, and other financial information used to determine the utility's rate of return, must also be changed.

Q. WHAT IS THE TOTAL MEASURE OF VALUE CLAIMED BY THE COMPANY FOR THE FTY ENDING NOVEMBER 30, 2015?

A. The Company's claimed measure of value for the FTY ending November 30, 2015, is $1,182,458,138 (Columbia Ex. No. 108, p. 3 of 11).

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE DOES THE COMPANY CLAIM WILL BE ASSOCIATED SOLELY WITH THE INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2016?

A. The Company's claimed measure of value for the FPFTY ending December 31, 2016, is $1,325,130,928 (Columbia Ex. No. 108, p. 3 of 11). Therefore, the

Company claims that $142,672,790 ($1,325,130,928 – $1,182,458,138) of rate base is associated solely with the inclusion of the FPFTY.

Q. DOES COLUMBIA'S $1,325,130,928 RATE BASE CLAIM FOR THE FPFTY ENDING DECEMBER 31, 2016, INCLUDE NET FORECASTED PLANT IN SERVICE?

A. Yes. Columbia Exhibit No. 108, Schedule 1, page 1 shows that the Company's plant in service at November 30, 2014, is $1,582,006,386. Pages 1-13 of Columbia Exhibit No. 108, Schedule 1 provide the Company's projected capital expenditures, plant additions, and retirements by month from December 2014 through December 2016, which support the Company's forecasted plant in service of $1,945,029,486 at December 31, 2016, included in the Company's $1,325,130,928 rate base claim for the FPFTY ending December 31, 2016 (Columbia Ex. No. 108, p. 3, col. 5).

Q. HOW MUCH NET PLANT IS THE COMPANY PREDICTING IT WILL ADD IN THE FUTURE TEST YEAR ENDING NOVEMBER 30, 2015, AND THE FOLLOWING THIRTEEN MONTHS ENDING DECEMBER 31, 2016?

A. The Company is predicting it will add $174,360,500 of net plant during the future test year ending November 30, 2015, and $188,662,600 of net plant during the following thirteen months ending December 31, 2016 (Columbia Ex. No. 108, p. 3, cols. 2 & 4, ln. 2).

Q. HOW HAS THE REGULATORY CONCEPT OF "USED AND USEFUL" TRADITIONALLY BEEN APPLIED TO DETERMINE WHETHER CERTAIN CAPITAL PROJECTS COULD BE PROPERLY INCLUDED IN A UTILITY'S RATE BASE?

A. Historically, a fundamental principle of utility regulation was that a public utility should be permitted to include projects in rate base and earn a reasonable return on its investments after they became "used and useful" for the utility's public service. Since the Company has elected to use a fully projected future test year for this base rate filing, the traditional interpretation of the "used and useful" requirement for rate base inclusion of plant under Act 11 has not be fully explored by the Commission to date and its precise application is presently uncertain. One of the main components to influence rate base, and thus revenue requirements, is additions to plant, also known as capital additions.

Q. HOW DO CAPITAL ADDITIONS INFLUENCE RATE BASE?

A. In regard to plant assets, rate base has two main components, plant balances and accumulated reserve for depreciation. Capital additions cause increases to plant-related rate base. Additionally, depreciation expense causes rate base to decrease. If capital additions were equal to depreciation expense, the plant-related rate base would remain constant. If plant-related rate base increases from one year to the next, it is because capital additions are greater than the depreciation expense.

Q. WHEN DID COLUMBIA LAST FILE A BASE RATE CASE?

A. Columbia's immediately preceding base rate case was filed March 21, 2014, only twelve months before the Company filed this case. In the previous proceeding the Company used the twelve-month period ending November 30, 2013 as the HTY, the twelve-month period ending November 30, 2014 as the FTY, and the twelve-month period ending December 31, 2015 as a FPFTY

Q. HAS THE COMMISSION APPROVED REPORTING REQUIREMENTS IN THE RESOLUTION OF PRIOR PROCEEDINGS RELATED TO PROJECTED CAPITAL ADDITIONS USED IN SETTING RATES USING THE FPFTY?

A. Yes. The Joint Petitions for Settlement filed by the parties to the previous two proceedings at Docket Nos. R-2012-2321748 and R-2014-2406274, and as approved by the Commission, required that Columbia provide to the Commission's Bureaus of Technical Utility Service and Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate, updates to CPA Exhibit No. 108, Schedule 1.

The Joint Petition for Settlement filed by the parties to the 2012 base rate proceeding required that Columbia provide, on or before October 1, 2013, an update to CPA Exhibit No. 108, Schedule 1, including actual capital expenditures, plant additions and retirements by month for the twelve months ending June 30, 2013. Another update through June 30, 2014 was required to be submitted on or before October 1, 2014. Additionally, as indicated in the Settlement, the Company was required to prepare and include as part of its next base rate case a comparison of its actual expenses and rate base additions for the twelve months ended June 30, 2014 to its projections.

The Joint Petition for Settlement filed by the parties to the 2014 base rate proceeding required that Columbia provide, on or before April 1, 2015, an update to CPA Exhibit No. 108, Schedule 1, including actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2014. Another update through December 31, 2015 is required to be submitted on or before April 1, 2016. Additionally, as indicated in the 2014 Settlement, the Company agreed to prepare and include as part of its next base rate case a comparison of its actual expenses and rate base additions for the twelve months ended December 31, 2015 to its projections.

Q. DID COLUMBIA PROVIDE THE REQUIRED UPDATE FOR THE TWELVE MONTHS ENDING JUNE 30, 2013 ON OR BEFORE OCTOBER 1, 2013?

A. Yes.

Q. HOW DO THE PROJECTED CAPITAL ADDITIONS AND RETIREMENTS IDENTIFIED IN THE PREVIOUS PROCEEDING AT DOCKET NO. R-2012-2321748 COMPARE TO ACTUALS FOR THE MONTHS OF JUNE 2012 THROUGH JUNE 2013 CONTAINED IN COLUMBIA'S INVESTMENT REPORT THAT WAS FILED PURSUANT TO THE SETTLEMENT OF THE 2012 BASE RATE PROCEEDING?

A. As shown on I&E Exhibit No. 3, Schedule 2, actual capital additions fell short of projections by approximately $4.48 million (2.7%) and actual retirements exceeded projections by approximately $1.26 million (8.7%) (I&E Ex. No. 3, Sch. 2, cols. B and G, ln. 14). Therefore, actual total plant in service as of June 30, 2013 was approximately $5.74 million (-$4.48 million - $1.26 million) <u>less</u> than the Company's projected plant in service at June 30, 2013.

Q. HAS THE COMPANY ADDRESSED THIS DISCREPANCY BETWEEN ITS INVESTMENT/RETIREMENT PROJECTIONS AND ACTUALS?

A. Yes. In response to informal discovery the Company provided an update containing the Company's actual investments and retirements for the period June 2012 through December 2013. The Company's update showed that as of December 31, 2013 actual capital additions not only met projections, but exceeded projections for the period June 2012 through December 2013 by approximately $6.0 million (2.3%). However, the difference between actual and projected retirements became even greater over the six month period from July 2013 through

December 2013. As of December 31, 2013 actual retirements exceeded projections by approximately $4.85 million (22.5%). Therefore, actual total plant in service as of December 31, 2013 was approximately $1.15 million ($6 million - $4.85 million) greater than the Company's projected plant in service at December 31, 2013.

Q. DID COLUMBIA PROVIDE THE REQUIRED UPDATE FOR THE TWELVE MONTHS ENDING JUNE 30, 2014 ON OR BEFORE OCTOBER 1, 2014?

A. No. Columbia's 2012 base rate case was filed September 28, 2012, only eighteen months before the Company filed its 2014 base rate case on March 21, 2014. Therefore, since there was an overlapping time period used to support the two cases, December 1, 2012 through June 30, 2014, the Company did not have the data to provide an update for the twelve months ending June 30, 2014 at March 21, 2014, and thus Columbia did not provided the required update.

Q. NOW THAT THE COMPANY HAS THE DATA TO PROVIDE AN UPDATE FOR THE TWELVE MONTHS ENDING JUNE 30, 2014, WERE YOU ABLE TO SUBSEQUENTLY PREPARE A COMPARISON OF COLUMBIA'S ACTUAL CAPITAL EXPENDITURES, PLANT ADDITIONS, AND RETIREMENTS TO ITS PROJECTIONS?

A. Yes. The Company's response to I&E-RB-16 provides the necessary data needed for this comparison. As shown on I&E Exhibit No. 3, Schedule 2, actual capital additions for the twelve months ending June 30, 2014 exceeded projections by approximately $35.08 million (20.5%) and actual retirements exceeded projections by approximately $1.64 million (10.9%) (I&E Ex. No. 3, Sch. 2, cols. B and G, ln. 27). Therefore, actual total plant in service as of June 30, 2014 was approximately $33.4 million ($35.08 million - $1.64 million) greater than the Company's projected plant in service at June 30, 2014.

Q. DID COLUMBIA PROVIDE THE REQUIRED UPDATE FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014 ON OR BEFORE APRIL 1, 2015?

A. Yes. The required update was provided as Columbia Exhibit NMP-1 in the current filing.

Q. HOW DO THE PROJECTED CAPITAL ADDITIONS AND RETIREMENTS IDENTIFIED IN THE PREVIOUS PROCEEDING AT DOCKET NO. R-2014-2406274 COMPARE TO ACTUALS FOR THE MONTHS OF JANUARY 2014 THROUGH DECEMBER 2014 CONTAINED IN COLUMBIA'S INVESTMENT REPORT THAT WAS FILED PURSUANT TO PARAGRAPH 25 OF THE APPROVED SETTLEMENT IN COLUMBIA'S 2014 BASE RATE PROCEEDING?

A. As shown on I&E Exhibit No. 3, Schedule 2, actual capital additions exceeded projections once again; this instance by approximately $11.59 million (6.04%). However, actual retirements fell short of projections by approximately $1.37 million (7.38%) (I&E Ex. No. 3, Sch. 2, cols. D and I, ln. 34). Therefore, actual total plant in service as of December 31, 2014 was approximately $12.96 million (11.59 million + $1.37 million) greater than the Company's projected plant in service at December 31, 2014.

Q. WHAT ARE SOME OF THE REASONS THE COMPANY PROVIDES FOR EXCEEDING CAPITAL ADDITION PROJECTIONS FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014?

A. Columbia indicates that the estimate used in the 2014 base rate proceeding was developed at a broad level with changes occurring due to a number of reasons. Shifting of capital occurred due to a delay in the construction of the training facility. Portions of the variances associated with this period happened because capital assigned to Account 376 – Mains for the estimate came in at actual to Account 378.2 – Measuring & Regulating Equipment, reflecting the broad based approach to developing the estimate. Variances can also be linked to additional projects related to pressure, such as the ERX program, along with valves and other related equipment.

Q. HAS THE TIME ARRIVED FOR COLUMBIA TO PROVIDE THE REQUIRED UPDATE FOR THE TWELVE MONTHS ENDING DECEMBER 30, 2016 OR HAS THE COMPANY SATISFIED THE REQUIREMENT TO PREPARE AND INCLUDE AS PART OF ITS NEXT BASE RATE CASE A COMPARISON OF ITS ACTUAL EXPENSES AND RATE BASE ADDITIONS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016 TO ITS PROJECTIONS?

A. No. As stated previously, Columbia's immediately preceding base rate case was filed March 21, 2014, only twelve months before the Company filed this case. Therefore, since there is an overlapping time period used to support the two cases, December 1, 2013 through December 31, 2015, the Company does not currently have the data to provide an update for the twelve months ending December 31, 2015, and thus Columbia has not provided the required update or satisfied the requirement.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING PLANT ADDITIONS THAT ARE PROJECTED TO BE IN SERVICE DURING THE FPFTY AND THUS INCLUDED IN RATE BASE FOR RATEMAKING PURPOSES?

A. Yes. In the proceeding at Docket No. L-2012-2317273, it is expected that the Commission will address the appropriate standard to be established for "used and useful" facilities that are projected to be in service during the FPFTY to be included in the rate base for ratemaking purposes. In addition to addressing that standard, I also recommend that the Company continue to provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2016, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending December 31, 2015. An additional update should be provided for actuals through December 31, 2016, no later than April 1, 2017.

Q. DO YOU CONSIDER IT ESSENTIAL THAT THE COMPANY BE DIRECTED TO PROVIDE THESE UPDATES?

A. Yes. Through use of the FPFTY, a utility is allowed to require ratepayers in essence to pre-pay a return on a utility's projected investment in future facilities that are not only not completed and providing service at the time the new rates take effect, but also are not subject to any ironclad guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be a mandate for the utility to provide timely updates to ensure the accuracy and verification of the Company's projections. Therefore, requiring Columbia to provide updates demonstrating that actual results are consistent with projections used in setting rates under a FPFTY methodology would allow the Commission to measure and verify the accuracy of the Company's projected investments in future facilities on a timely basis.

PRESENT RATE REVENUE

Q. WHAT IS COLUMBIA'S CLAIM FOR PRESENT RATE REVENUES FOR THE FPFTY ENDING DECEMBER 31, 2016?

A. The Company is claiming that it will receive $534,899,150 in present rate revenue (Columbia Ex. No. 103, p. 9, col. 3, ln. 29).

Q. IS THIS $534,899,150 FIGURE BASED ON A PROJECTED NUMBER OF CUSTOMERS AND PROJECTED SALES VOLUMES FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016?

A. Yes. The Company projected the number of customers and projected normalized usage by class to arrive at the $534,899,150 in total present rate revenue. The proper number of customers and sales volumes is critical in the determination of present and proposed revenue.

Q. WHAT TWO AREAS OF PRESENT RATE REVENUE DO YOU WISH TO ADDRESS?

A. First, I will address the projected decline in average customer usage. Second, I will address the competitive discounts granted to certain customers.

RESIDENTIAL USAGE PER CUSTOMER

Q. WHAT IS THE COMPANY'S CLAIM REGARDING RESIDENTIAL USAGE?

A. The Company claims that residential usage is declining. According to the Company, Residential customer usage projections should include a reduction to account for limited end uses for natural gas, accelerated appliance replacements, high efficiency appliance installations, modifications to new and existing buildings which are designed to decrease energy consumption, changes in consumer usage behavior in response to energy price changes, and other economic influences (Columbia St. No. 2, pp. 15-16).

Q. DID THE COMPANY MAKE THE SAME CLAIM CONCERNING RESIDENTIAL USAGE DECLINE IN ITS PREVIOUS BASE RATE PROCEEDING AT DOCKET NO. R-2014-2406274?

A. Yes. Ms. Efland states on page 13 of Columbia Statement No. 2 at Docket No. R-2014-2406274 that "With the return of more temperate weather, the data should smooth out and reveal the continuation of the underlying downward trend."

Q. IN THE PREVIOUS PROCEEDING, DID THE COMPANY MAKE A PROJECTION CONCERNING THE AVERAGE USE PER RESIDENTIAL CUSTOMER FOR THE FUTURE TEST YEAR ENDING NOVEMBER 30, 2014, GUIDED BY ITS CLAIM THAT RESIDENTIAL USAGE IS DECLINING?

A. Yes. As shown on I&E Exhibit No. 3, Schedule 3, the Company projected an average composite use per Residential customer of 87.39 Dth per year for the twelve months ending November 30, 2014 (I&E Ex. No. 3, Sch. 3, col. B, ln. 38).

Q. WAS MS. EFLAND CORRECT IN HER PROJECTED DECLINE IN RESIDENTIAL USE PER CUSTOMER FOR THE TWELVE MONTHS ENDING NOVEMBER 30, 2014?

A. No. Based on data for that period which is now available, the actual weather normalized usage per Residential customer for the twelve months ending November 30, 2014 was 91.8 Dth (I&E Ex. No. 3, Sch. 6, p. 2). Therefore, Ms. Efland's claim that Residential usage will continue to decline and her subsequent projected decline in Residential use per customer for the twelve months ending November 30, 2014 were both incorrect. In fact, the opposite occurred; actual data shows that Residential use per customer increased during this period by 1.7 Dth (90.1 Dth – 91.8 Dth = 1.7 Dth)[1].

Q. WHAT AVERAGE USE PER RESIDENTIAL CUSTOMER IS THE COMPANY PROJECTING IN THE CURRENT PROCEEDING?

A. Based on the Company's proof of revenue schedules (Columbia Ex. No. 103, Sch. 1, pp. 13-18) and the Company's projected number of customers (I&E Ex.

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[1] I&E Exhibit No. 3, Schedule 6, page 2.

No. 3, Sch. 4), I determined the Company is projecting that the average usage per RSS customer will be 83.8 Dth per year (I&E Ex. No. 3, Sch. 5, col. B, ln. 2). The Company is also projecting that the average usage per Residential Distribution Service ("RDS") customer will be 90.02 Dth per year (I&E Ex. No. 3, Sch. 5, col. B, ln. 16) and the average usage per Residential CAP customer will be 126.46 Dth per year at the end of the FPFTY (I&E Ex. No. 3, Sch. 5, col. B, ln. 29). Therefore, I conclude that the Company is projecting an average composite use per Residential customer of 87.44 Dth per year (I&E Ex. No. 3, Sch. 5, col. B, ln. 38).

Q. WHAT DATA DOES THE COMPANY USE AS PART OF ITS PROJECTION OF USAGE DECLINE FOR RESIDENTIAL CUSTOMERS?

A. The Company analyzed usage for the past twenty-two years (Columbia St. No. 2, pp. 12-14).

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTED AVERAGE COMPOSITE RESIDENTIAL USAGE?

A. No. I believe the Company has understated its projected residential usage.

Q. WHAT LEVEL OF RESIDENTIAL USAGE DO YOU RECOMMEND?

A. I believe that the average composite use per Residential customer will be 92.92 Dth per year for the FPFTY ending December 31, 2016 (I&E Ex. No. 3, Sch. 5, col. H, ln. 38). With respect to efforts to calculate projected usage by residential customers today, I believe a 20-year time period is too long.

Comparing usage to twenty years ago, which predated customer initiatives the Company uses to support its assertion of usage decline, tends to exaggerate the impact of decreased consumption by placing undue emphasis on older data, where consumption was higher, which is not truly reflective of current consumption patterns. This, in turn, dilutes the most recent actual changes in usage, causing the Company to improperly reflect declines in consumption it believes are likely to be experienced going forward and understate projected usage. Based on recent history and the Company's unreliable projections in past cases, it is not likely that consumption will continue to decrease at the level projected by the Company.

Q. HOW DID YOU DETERMINE THE 92.92 DTH PER YEAR PER RESIDENTIAL CUSTOMER?

A. Using the data contained in the Company's response to I&E-RS-1-D (I&E Ex. No. 3, Sch. 6), I calculated the average change in usage for Residential customers over the most recent six-year period (2009-2014) to be an increase of 0.56 Dth per year (I&E Ex. No. 3, Sch. 7, col. C, ln. 13). Based on the actual weather normalized usage per customer for 2014 of 91.8 Dth, I project that the average

Residential customer will use 92.92 Dth for the FPFTY ending December 31, 2016 (I&E Ex. No. 3, Sch. 7, col. B, ln. 16).

Q. **DOES THE MORE RECENT DATA INDICATE THAT USAGE HAS REMAINED FAIRLY LEVEL?**

A. Yes. Between 2008 and 2014 average usage per Residential customer has stayed at approximately 90 Dth per year. The data also shows that weather normalized Residential usage actually increased in 2007, 2010, 2013, and again in 2014.

Q. **WHAT USAGE SHOULD BE ADJUSTED SO THAT THE TOTAL USAGE PER RESIDENTIAL CUSTOMER EQUALS THE 92.92 DTH PER YEAR DESCRIBED ABOVE?**

A. I recommend that the average use per Residential RSS customer be increased to 91.47 Dth per year so that the average composite usage for all Residential customers is 92.92 Dth per year (I&E Ex. No. 3, Sch. 5, col. H, ln. 2).

Q. **HOW MUCH SHOULD THE COMPANY'S PROJECTED RESIDENTIAL RSS SALES VOLUME BE INCREASED SO THAT THE AVERAGE USE PER RESIDENTIAL RSS CUSTOMER IS 91.47 DTH PER YEAR?**

A. As shown on I&E Exhibit No. 3, Schedule 4, line 3, if Residential RSS customer usage is increased by approximately 2,128,350 Dth (25,409,026 Dth – 23,280,676

Dth), the average use per customer increases by 7.67 Dth per year to 91.47 Dth per year.

Q. WHAT TOTAL ADJUSTMENT TO RESIDENTIAL PRESENT RATE REVENUES YOU ARE RECOMMENDING AS A RESULT OF YOUR ANALYSIS OF RESIDENTIAL USE PER CUSTOMER?

A. My recommended average use per RSS customer increases the present revenues for the Residential class by $20,730,130, as shown on I&E Exhibit No. 3, Schedule 8, column C, line 15.

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDED $20,730,130 INCREASE IN PRESENT REVENUES, SHOULD THERE ALSO BE A CORRESPONDING INCREASE IN THE COST OF GAS EXPENSE?

A. Yes. If the Commission accepts my recommendation, the Company must purchase more gas than what is reflected in the filing.

Q. WHAT IS THE CORRESPONDING INCREASE IN THE COST OF GAS EXPENSE?

A. If the Commission accepts this present revenue adjustment, there should be a corresponding increase of $11,469,892 in the cost of gas expense for the additional gas, as shown on I&E Exhibit No. 3, Schedule 8, column C, line 16.

COMPETITIVE DISCOUNTS

Q. WHAT ARE COMPETITIVE DISCOUNTS?

A. Competitive discounts occur when a company reduces or waives all or part of any tariff charge. This is sometimes referred to as flexing of rates.

Q. DOES THE COMPANY FLEX RATES FOR ANY OF ITS CUSTOMERS?

A. Yes. The Company provides service to 44 customers (flex customers) at less than the full tariff rate. These customers are listed on the Company's proprietary response to I&E-RS-2-D (I&E Ex. No. 3, Sch. 9).

Q. ARE THERE VARIOUS REASONS FOR PROVIDING SERVICE TO CUSTOMERS AND NOT CHARGING THE FULL TARIFF RATES?

A. Yes. The various claimed reasons include competition from other Local Distribution Companies (LDCs), interstate pipelines, and alternative fuel.

Q. WHAT IS THE MOST PREVALENT REASON FOR NOT CHARGING THE FULL TARIFF RATE?

A. The most prevalent reason for flexing rates is competition from other LDCs, which is the issue that I would like to address in my direct testimony.

Q. DOES COLUMBIA FACE COMPETITION FROM OTHER LOCAL DISTRIBUTION COMPANIES?

A. Yes. In western Pennsylvania, the service territories of Equitable Gas Company LLC (Equitable), Peoples Natural Gas Company, LLC (Peoples) and Peoples-TWP, LLC (Peoples-TWP) overlap. Therefore, some customers have a choice of multiple LDCs.

Q. DID THE COMPANY PROVIDE A SCHEDULE THAT SHOWS WHAT EACH OF THE 44 FLEX CUSTOMERS WOULD PAY IF THEY PAID FULL PRESENT RATES?

A. Yes. The Company's proprietary response to I&E-RS-2-D showed the 44 flex customers, the rate schedule, the customer's annual bill, and the customer's annual bill if they paid Columbia's full tariff rates (I&E Ex. No. 3, Sch. 9).

Q. HOW MANY OF THE 44 FLEX CUSTOMERS RECEIVE A DISCOUNT SOLELY AS A RESULT OF COMPETITION FROM ANOTHER LDC?

A. The Company's proprietary response to I&E-RS-2-D showed that 25 of the flex customers receive a discount solely as a result of competition from other LDCs.

Q. WHAT IS THE TOTAL AMOUNT OF REVENUE COLUMBIA DOES NOT RECEIVE AS A RESULT OF GRANTING THESE DISCOUNTS?

A. As a result of flexing rates for other LDCs, the Company does not receive approximately $1,705,788 in annual revenue from 25 customers (I&E Ex. No. 3, Sch. 10, col. D, ln. 29).

Q. WHERE DOES THE COMPANY RECOVER THIS $1,705,788 THAT IS NOT PAID BY THE 25 FLEX CUSTOMERS?

A. The Company recovers this $1,705,788 from customers who pay the full tariff rates.

Q. AT THIS TIME, DO YOU HAVE ANY RECOMMENDATION CONCERNING FLEX RATE CUSTOMERS WHOSE TARIFFED CHARGES ARE DISCOUNTED DUE TO COMPETITION FROM OTHER LDCS?

A. No. The situation whereby captive ratepayers pay for the revenue shortfall associated with discounted rate agreements is currently the subject of the Commission initiated generic investigation at Docket No. I-2012-2320323. Therefore, at this time I have no recommendation and will await the Commission's decision addressing whether flex discounts solely as a result of competition from other LDCs should be permitted to continue or, if permitted to continue, under what circumstances it will be considered appropriate.

COST OF SERVICE

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study 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. DID THE COMPANY PROVIDE A COST OF SERVICE STUDY IN ITS FILING?

A. Yes. The Company provided three cost of service studies in Columbia Exhibit No. 111. Schedule 1 of Columbia Exhibit No. 111 provides the results of a study using the Customer-Demand allocation method. The second cost of service study is provided in Schedule 2 of Columbia Exhibit No. 111 and utilizes the Peak and Average demand allocation method. The third cost of service study is provided in

Schedule 3 of Columbia Exhibit No. 111 and is an average of the Customer-Demand study and the Peak and Average study.

The cost of service studies presented by Columbia are sponsored by Mr. Brian E. Elliott. Columbia's studies each use a basic three step process of cost analysis: (1) functionalization; (2) classification of functionalized costs into demand, commodity, and customer cost categories; and (3) class allocation of functionalized, classified costs among the rate classes.

Q. HOW DO THE CUSTOMER-DEMAND AND THE PEAK AND AVERAGE COST OF SERVICE STUDIES PREPARED BY COLUMBIA DIFFER?

A. The two cost of service studies prepared by Columbia differ in that they are based on two alternative methods of allocating mains to the various classes of service. The Customer-Demand method classifies distribution mains as partially customer related and partially demand related. The customer portion of mains is then allocated to classes based on number of customers, while the demand portion of mains is allocated to classes based on contributions to peak (design) day demand. This methodology has been rejected in other natural gas base rate cases.

The second cost of service study sponsored by Mr. Elliott utilizes the Peak and Average methodology. This methodology allocates distribution mains to classes based partially on annual consumption (average demand) and partially on contributions to peak day demand. This methodology has been accepted by the Commission. There is simply no demonstrated reason here to consider allocating a percentage of the cost of distribution mains based on the number of customers. Although mains serve customers, it is the throughput that determines the type of main investment. Because it is the load that determines the main investment, not the number of customers served, the Peak &Average allocation methodology is the most appropriate allocation methodology because it is based on this premise of load based investment. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served. To illustrate this imagine two separate streets: Street A has only one commercial customer that exhibits a maximum demand of 10 Dth and Street B has 10 residential customers, each with a peak demand of 1 Dth. The distribution main serving the 10 residential customers on Street B would have to be sized to deliver 10 Dth at peak. The distribution main on Street A would also have to be sized to deliver 10 Dth at peak to serve the 1 commercial customer. So while mains serve customers, the number of customers does not determine the main investment.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE IMPACT OF THE TWO COST OF SERVICE METHODOLOGIES?

A. Yes. The SDS/LGSS rate group's relative return at present rates based on allocating mains on the Customer-Demand method is 2.26, which implies that the cost of providing service is less than the revenue received from that class (Columbia Ex. No. 111, Sch. 1, p. 2). Conversely, according to the study utilizing the Peak & Average method, the relative return for the SDS/LGSS rate group at present rates is 0.79 which implies that the cost of providing service is more than the revenue received from this rate group (Columbia Ex. No. 111, Sch. 2, p. 2).

Q. WHY DOES SUCH A LARGE DIFFERENCE OCCUR?

A. This difference is due primarily to the fact that the Customer-Demand study places more of a cost obligation on the customer component of the distribution system, i.e., the system has to reach all customers, which would have a greater impact on the largest class of customers as defined by number of customers, rather than the demand component of the distribution system, i.e., the system has to be sized to meet peak demand, which would have a greater impact on largest class of customers as defined by volume.

Q. WHICH COST OF SERVICE STUDY DID THE COMPANY EMPLOY TO ALLOCATE THE PROPOSED REVENUE INCREASE?

A. Company witness Balmert testifies that he most relied upon the Average study, which has an equal weighting of the Customer-Demand and Peak & Average studies, to provide guidance for the revenue allocation and rate design process (Columbia St. No. 11, p. 4).

Q. WHICH COST OF SERVICE STUDY DO YOU RECOMMEND THAT THE COMMISSION USE AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. I recommend that the Commission rely on the cost of service study that is based on allocating mains based on the Peak & Average method.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO ALLOCATE MAINS BASED ON THE PEAK AND AVERAGE METHOD?

A. The Peak and Average method is the most appropriate method. It is reasonable to allocate distribution mains investment on the basis of annual as well as peak demands because Distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand study. The basic reason why Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED USE OF THE PEAK & AVERAGE METHOD?

A. Yes. The Commission has previously reflected its recognition that distribution mains are built on the basis of year-round demands as well as peak demands. In the National Fuel Gas Distribution Company ("NFGD") 1994 base rate proceeding, the Commission accepted the Peak & Average methodology, stating "[t]he Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact." (*Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 83 Pa. PUC 262 (1994).

Q. HOW DID THE COMPANY CLASSIFY AND ALLOCATE THE MAINS AND MAINS-RELATED ACCOUNTS FOR THE PEAK & AVERAGE STUDY?

A. The Peak & Average study sponsored by Company witness Elliott reflects a 50 percent allocation of distribution mains investment based on design peak demand and 50 percent on the basis of annual demands.

Q. DO YOU AGREE WITH THIS MANNER OF CLASSIFYING AND ALLOCATING THE FIXED COST OF MAINS AND MAINS-RELATED ACCOUNTS?

A. Yes. The Commission previously determined in a 1994 Opinion and Order in the Pennsylvania American Water Company case at Docket No. R-00932670, Order entered July 26, 1994, at pages 111- 115, that direct customer costs include "the depreciation, return and income taxes associated with meter and service investment, the operation and maintenance expense for meters and services, and the expense associated with meter reading and billing." Mains are not included in any of these categories, and therefore should not be considered or classified as a customer cost. The basis for this determination is that the quantity and investment in mains does not change significantly if one customer joins or leaves the system. Mains are built to deliver gas, and the cost of mains cannot be assigned to one specific customer. Therefore, no portion of the fixed costs or depreciation expense associated with mains should be allocated to the customer cost function.

In a more recent Opinion and Order, the Commission reaffirmed that the cost of mains should be allocated on a combination of throughput and demand, and therefore not allocated to the customer function (PPL Gas Utilities, Docket No. R-00061398, order entered February 8, 2007).

Q. BEFORE ADDRESSING REVENUE ALLOCATION AMONG THE VARIOUS RATE CLASSES, IS COLUMBIA PROPOSING ANY CHANGES TO THE MANNER IN WHICH THE RATE SCHEDULES ARE GROUPED IN ALLOCATING THE COST OF SERVICE?

A. Yes. The Large General Sales Service ("LGSS") customers, previously presented in the cost of service study as its own rate class, have been split between and combined with either the existing Small Distribution ("SDS") or Large

Distribution Service ("LDS") classes of customers, based upon each class' cost of service. SDS and the lower band of LGSS have been combined and presented in the Company's cost of service studies as "SDS/LGSS." LDS and the upper band of LGSS have likewise been combined and presented in the Company's cost of service studies as "LDS/LGSS."

The merging of the LGSS base rate charges with the base rate charges of the SDS and LDS rate classes is addressed by Mr. Balmert in Columbia Statement No. 11, pages 17-22. As indicated by Mr. Balmert, this is possible because the only difference between the LGSS rate class and the SDS and LDS classes is the upstream supply and capacity charges. As for the distribution service, there is no difference in the service between that of SDS customers and LGSS customers whose annual usage is less than 540,000 therms or a material difference in the cost to serve these customers. Therefore, cost recovery rates for the two rate classes should be the same. Likewise, there is no difference in distribution service between that of LDS customers and LGSS customers whose annual usage is greater 540,000 therms or a material difference in the cost to serve these customers. Therefore, cost recovery rates for these two rate classes should also be the same.

Q. IS THIS REVISION REASONABLE?

A. Yes.

INCREASE REQUEST

Q. WHAT PERCENT INCREASE IS COLUMBIA PROPOSING FOR THE VARIOUS CUSTOMER CLASSES AS PRESENTED IN THE COST OF SERVICE STUDIES?

A. The Company's proposed revenue distribution is presented in the following table (Columbia Ex. No. 111, Sch. 3, pp. 1-2).

Company Proposed Revenue Distribution				
Class	**Present Rates**	**Proposed Rates**	**Increase**	**Percent**
RSS/RDS	$387,285,568	$423,124,673	$35,839,105	9.25%
SGSS/SCD/SGDS	$110,408,593	$116,565,397	$6,156,804	5.58%
SDS/LGSS	$18,822,163	$20,606,757	$1,784,594	9.48%
LDS/LGSS	$16,642,308	$19,032,697	$2,390,389	14.4%
MLDS	$1,740,519	$1,740,853	$334	0.02%
Total	**$534,899,150**	**$581,070,377**	**$46,171,228**	**8.63%**

It should be noted that the Company's proposed amounts in the table above reflect the effects of the Company's proposed CAC Rider, as well as the Company's existing Riders.

Q. DESCRIBE HOW COLUMBIA IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. The Company is attempting to move the rate groups towards their respective costs of service. Considering that the Main Line Distribution Service ("MLDS") rate class exhibited a relative rate of return above 1.0 at present rates in Columbia's preferred cost of service study, which utilizes the average of the Customer-Demand and Peak & Average studies, the present level of revenues was maintained for this class. The relatively small increase in revenue for the MLDS class shown below is mostly due to an increase in miscellaneous revenue allocated to this rate class. Also, slightly attributable to the small increase in revenue for the MLDS class is the Company's attempt to offset revenue recovery of the proposed CAC Rider through a small decrease to the volumetric charges.

The residential classes (RSS/RDS) received an increase intended to move the classes toward parity with the overall total Company return. The LDS/LGSS rate group also received an increase intended to raise the relative rate of return from 0.84227 to 0.84275. The limit on the increases proposed for the SGSS/SCD/SGDS and SDS/LGSS rate groups is an effort to lower the relative rates of return for both groups to 1.2013 (Columbia Ex. No. 111, Sch. 3, p. 1, ln. 14).

Q. WHAT ASPECTS OF RATE STRUCTURE DOES THE COMMISSION CONSIDER WHEN ESTABLISHING PROPOSED RATES?

A. One of the considerations in establishing proposed rates is the resulting rate of return by customer class and the corresponding relative rate of return by class (how the rate of return for each class compares to the system average rate of return). The optimum goal should be to establish proposed rates so that the revenue received from a particular class is equal to the corresponding costs of providing service to that class.

A relative rate of return above 1.00 for a class indicates that the cost of providing service is less than the revenue received from that class. A relative rate of return below 1.00 for a class indicates that the cost of providing service is more than the revenue received from that class. The relative rate of return for each class, as shown by the Company's Peak & Average study is shown on Columbia Exhibit No. 111, Schedule 2, page 1, line 14.

Q. **AS PREVIOUSLY INDICATED, THE COMPANY'S PROPOSED CLASS REVENUE INCREASE ALLOCATION IS BASED UPON THE COMPANY'S PREFERRED COST OF SERVICE STUDY, WHICH UTILIZES THE AVERAGE OF THE CUSTOMER-DEMAND AND PEAK & AVERAGE STUDIES. HAVE YOU EVALUATED THE REASONABLENESS OF THE COMPANY'S PROPOSED CLASS INCREASES UTILIZING PEAK & AVERAGE METHOD, WHICH YOU RECOMMEND BE USED AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?**

A. Yes. Based on the results of the Peak & Average cost of service study and the Company's proposed revenue allocation, the SGSS/SCD/SGDS, LDS/LGSS, and

MLDS classes move closer to the system average rate of return. However, the relative rate of return for the residential class has moved slightly away from the system average rate of return, from 1.09 under present rates to 1.11 under proposed rates. Additionally, the relative rate of return for the SDS/LGSS class has moved slightly away from the system average rate of return, from 0.79 under present rates to 0.77 under proposed rates. This indicates that under proposed rates the residential (RSS/RDS) class would be moving further over parity (system average of 1.0) and the SDS/LGSS class would be moving further under parity (Columbia Ex. No. 111, Sch. 2, pp. 1-2). The Commission should consider the movements in relative rates of return when establishing proposed rates.

The following table compares the Company's cost of service utilizing the Peak & Average method and its revenues under proposed rates as filed.

Customer Class	**Cost of Service (Peak & Average)**	**Proposed Revenues**	**Difference**
RSS/RDS	$410,065,183	$423,115,183	$13,050,000
SGSS/SCD/SGDS	$116,568,299	$116,568,299	$0
SDS/LGSS	$23,012,096	$20,608,596	($2,403,500)
LDS/LGSS	$31,037,447	$19,037,447	($12,000,000)
MLDS	$387,353	$1,740,853	$1,353,500
Total	$581,070,377	$581,070,377	$0

It appears that the residential class (RSS/RDS) received an increase in proportion to their cost-based revenue requirement at proposed revenues levels, but was also allocated an additional $13,050,000 increase in order to lower the overall returns for the groups that are over-contributing (MLDS) and as a result of the limited increases proposed for the SDS/LGDSS and LDS/LGSS groups. In effect, the residential class (RSS/RDS) is recovering over 90% of the SDS/LGSS and LDS/LGSS revenue shortfall.

Q. DO YOU RECOMMEND AN ALTERNATE CLASS REVENUE INCREASE ALLOCATION THAT IS CONSISTENT WITH COMMISSION PRACTICE IN WHICH COST OF SERVICE RESULTS ARE CONSIDERED UTILIZING THE PEAK & AVERAGE METHOD?

A. Yes. My recommended revenue allocation adjusts the Company's proposed revenue allocation by re-allocating $3,500,000 from the RSS/RDS rate group to the SGSS/SCD/SGDS and SDS/LGSS rate groups. The result, as shown on I&E Exhibit No. 3, Schedule 11, is that the rates of return of the various customer classes move closer to the system average. Additionally, due to the limited increases for the SDS/LGSS and LDS/LGSS rate groups, my recommended revenue allocation makes the relative rates of return for the RSS/RDS and SGSS/SCD/SGDS rate groups the same. With both groups producing approximately the same relative rate of return, they are contributing the same proportion of revenue shortfall created by the other rate groups (I&E Ex. No. 3, Sch. 11, ln. 16).

SCALEBACK

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE OF $46,171,228?

A. If the Commission grants Columbia less than the full increase it has requested, I recommend that the proposed revenue increases for the RSS/RDS, SGSS/SCD/SGDS, and SDS/LGS rate groups be reduced, as shown on I&E Exhibit No. 3, Schedule 12, to produce the level of revenue the Commission allows the Company the opportunity to recover.

Q. DESCRIBE HOW THE SCALE BACK ON I&E EXHIBIT NO. 3, SCHEDULE 12 SHOULD BE APPLIED.

A. This schedule shows how the scale back should be applied based on the increase the Commission allows in this proceeding. It is important to recall the first column of this schedule of my exhibit is the amount of the scale back and not the amount of increase. For example, if the Commission grants an increase of $45,171,228 ($46,171,228 - $1,000,000), the $1,000,000 decrease should be allocated entirely to the RSS/RDS rate group (I&E Ex. No. 3, Sch. 12, ln. 2). If the Commission grants an increase of $42,171,228 ($46,171,228 - $4,000,000), 80% of the $4,000,000 decrease should be allocated to the RSS/RDS group and 20% to the SGSS/SCD/SGDS group (I&E Ex. No. 3, Sch. 12, ln. 6). If the Commission grants an increase of $12,171,228 ($46,171,228 - $34,000,000), 77% of the $34,000,000 decrease should be allocated to the RSS/RDS group, 22% to the SGSS/SCD/SGDS group, and 1% to the SDS/LGSS group (I&E Ex. No. 3, Sch. 12, ln. 21).

Q. WHAT IF THE COMMISSION GRANTS AN INCREASE BETWEEN THE REVENUE LEVELS YOU SELECTED?

A. The amounts on I&E Exhibit No. 3, Schedule 12 should be interpolated to achieve the increase and ultimate revenue level the Commission approves in this case.

Q. HOW DOES YOUR SCALE BACK RECOMMENDATION AFFECT THE RELATIVE RATES OF RETURN FOR THE RSS/RDS AND SGSS/SCD/SGDS RATE GROUPS?

A. Since I have recommended no scale back for the LDS/LGSS or MLDS groups due to there being either a limited increase proposed for the group or no proposed increase for the group, my scale back recommendation as shown on I&E Exhibit No. 3, Schedule 12 is an effort to keep the relative rates of return for the RSS/RDS and SGSS/SCD/SGDS groups as close to one another as possible. With both groups, the RSS/RDS and SGSS/SCD/SGS rate groups, producing approximately the same relative rate of return, they are contributing the same proportion of revenue shortfall.

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION REDUCES THE INCREASE BELOW $5,913,028?

A. If the Commission further reduces the allowed increase below $5,913,028 ($46,171,228 - $40,258,200), I recommend that the revenues for all classes, excluding the MLDS class, be reduced so that the increase for each class is proportional to the percentage increase shown on I&E Exhibit No. 3, Schedule 13, line 22. I recommend that the MLDS rates not be scaled back, since the Company has proposed no increase in base rates for this class.

CUSTOMER COST ANALYSIS

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

A. A customer cost analysis is part of a cost of service study that includes only customer costs. It is used to determine the appropriate customer charges for the various classes.

Q. DID THE COMPANY PREPARE AN ANALYSIS TO SUPPORT ITS PROPOSAL TO INCREASE THE CUSTOMER CHARGES?

A. Yes. The Company completed two customer charge analyses presented in Columbia Exhibit No. 111, Schedule 1, pp. 14-18, though it refers to them as a "system charge." Pages 14 through 16 contain the Company's customer charge study based on the Customer-Demand COSS and includes the customer portion of mains costs. The other study included on pages 17 and 18 of Schedule 1 is similar, but excludes the customer component of mains and other operations. Columbia's analysis including the customer portion of mains costs results in a Residential customer charge of $35.90 per month (Columbia Ex. No. 111, Sch. 1, p. 14, col. E, ln. 40) while its analysis excluding the customer component of mains produces a customer charge of $18.15 per month (Columbia Ex. No. 111, Sch. 1, p. 17, col. E, ln. 37).

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED WHAT ITEMS SHOULD BE RECOVERED IN A CUSTOMER CHARGE?

A. Yes. In its Order entered August 5, 2004, in the Aqua Pennsylvania base rate case at Docket No. R-0038805 ("Aqua"), the Commission endorsed the company's analysis, presented in rebuttal testimony, which demonstrated the direct costs to be recovered in a customer charge. Based on the analysis in Aqua, the Commission found that the determination of a customer charge should be limited to the following items: Transmission and Distribution Operating and Maintenance Expenses associated with meters and services, Customer Accounts Expenses, expenses associated with Employee Health Plans, Federal and State Payroll Taxes, expenses for PUC/OCA Assessments, and the depreciation expenses and rate base related return and income taxes related to meters, services, office buildings, office furniture and equipment and computers.

Q. DOES THE COMPANY RECOGNIZE WHAT THE COMMISSION HAS DETERMINED TO BE APPROPRIATE ITEMS TO BE INCLUDED IN THE CUSTOMER CHARGE?

A. It would appear so, yes. As an alternative to the Company's more-inclusive customer cost analyses presented in Columbia Exhibit No. 111, Schedule 1, pages 14-16, Mr. Elliott has prepared an additional customer cost analysis, which excludes the customer component of mains and other operations (Columbia St. No. 11, pp. 17-18). An update to this analysis calculated under the Peak and Average method has been provided by the Company in its response to I&E-RS-27-D (I&E Ex. No. 3, Sch. 14). Based on the Company's analysis, the Company claims that it incurs $17.93 per month in customer costs for each RSS/RDS customer, $23.78 per month in customer costs for each SGSS/SCD/SGDS customer, $179.33 per month is customer costs for each SDS/LGSS customer, $1,026.02 per month in customer costs for each LDS/LGSS customer, and $362.75 per month in customer costs for each MLDS customer (I&E Ex. No. 3, Sch. 14, ln. 37).

Q. WHAT ITEMS CLAIMED BY THE COMPANY SHOULD NOT BE INCLUDED IN ITS CUSTOMER COST ANALYSIS AND RECOVERED IN THE CUSTOMER CHARGE?

A. In the Aqua case, the Commission found that Aqua met its statutory burden of establishing the reasonableness of its proposed customer charges based upon the company's direct customer cost analysis attached to the company's rebuttal testimony that supported the reasonableness of the company's proposed customer charges. Therefore, guided by the Commission's conclusions in that case, I have determined that the following items should be removed from Columbia's customer cost analysis: (1) miscellaneous customer accounts expenses and uncollectibles revenue; (2) customer assistance expense, informational and instructional expenses, and miscellaneous customer service and information expenses; (3) demonstration and advertising expenses; and (4) all claimed administrative and general expenses with the exception of employee pension and benefits.

Q. HAVE YOU CALCULATED WHAT THE MONTHLY CUSTOMER COSTS SHOULD BE FOR COLUMBIA?

A. Yes. My customer cost calculation, guided by the analysis and Commission decision in the Aqua case, is presented on Schedule 15 of I&E Exhibit No. 3. Based on my customer cost analysis, I determined that the Company incurs $16.93 per month in customer costs for each RS/RDS customer, $23.36 per month in customer costs for each SGSS/SCD/SGDS customer, $191.69 per month in customer costs for each SDS/LGSS customer, $1,146.97 per month in customer costs for each LDS/LGSS customer, and $336.35 per month in customer costs for each MLDS customer (I&E Ex. No. 3, Sch. 15, ln. 38).

Q. WHAT IS YOUR RATIONALE FOR REMOVING CUSTOMER ASSISTANCE EXPENSE FROM THE COMPANY'S CUSTOMER COST ANALYSIS?

A. In a recent PPL Electric ("PPL") base rate case, Order entered December 28, 2012, at Docket No. R-2012-2290597, the Commission identified the specific costs that are appropriately included in a customer charge. This determination by the Commission in the 2012 PPL case supports my recommendation here to remove claimed customer assistance expense from the Company's customer cost analysis for the determination of the appropriate customer charge. In the PPL case, I noted that such universal service rider costs were specifically excluded from customer service costs that would be recovered in a customer charge.

Q. WHAT IS YOUR RATIONALE FOR REMOVING ALL CLAIMED ADMINISTRATIVE AND GENERAL EXPENSES WITH THE EXCEPTION OF EMPLOYEE PENSION AND BENEFITS?

A. As explained above, the company's direct customer cost analysis contained in Aqua's rebuttal testimony, on which I have based my customer cost analysis, only includes administrative and general expenses associated with Employee Health Plans and Payroll Taxes. Therefore, guided by the Commission's conclusion in that case, I have determined that these are the only allowable administrative and general expenses.

RESIDENTIAL RATE DESIGN

Q. DESCRIBE COLUMBIA'S CURRENT AND PROPOSED RESIDENTIAL RATES.

A. Columbia's current Residential rates consist of a $16.75 per month customer charge and a single delivery rate of $4.2138 for each Dth of gas delivered. Under Columbia's proposed Residential rate design a customer would pay a monthly customer charge of $20.60, based upon its over-inclusive customer cost analysis and a single delivery rate of $4.7354 per Dth for all gas delivered. Customers will continue to pay on a volumetric basis through Riders PGC, GPC, MFC, CC, and USP. Additionally, the Company is not seeking to modify its three year pilot residential Weather Normalization Adjustment ("WNA") which the parties agreed to in its rate case proceeding at Docket No. R-2012-2321748.

Q. WHAT IS THE CLAMED BASIS FOR COLUMBIA'S PROPOSED 23% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE?

A. The claimed basis for increasing the residential customer charge is the Company's over-inclusive customer cost analyses.

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE LEVEL OF CUSTOMER CHARGE FOR THE RESIDENTIAL CLASS?

A. I recommend that the present $16.75 per month residential customer charge be increased to 16.93 per month. There is no cost basis for increasing the present customer charge for residential customers to the level requested by the Company. As shown in my customer cost analysis, the Company incurs $16.93 per month in direct and indirect costs to serve the residential class (I&E Ex. No. 3, Sch. 15, col. E, ln. 38). Therefore, I recommend that the present $16.75 per month customer charge for residential customers should not be increased by more than $0.18 per month ($16.93 - $16.75).

<u>CUSTOMER CHARGES – SGSS/SCD/SGDS</u>

Q. IS THE COMPANY PROPOSING TO INCREASE THE MONTHLY CUSTOMER CHARGES FOR SGSS, SCD, AND SGDS CLASS CUSTOMERS?

A. Yes. Columbia proposes to increase the customer charge for SGSS, SCD, and SGDS customers using less than 6,440 therms annually from $21.25 to $27.75 per month. Columbia proposes to increase the customer charges for SGSS, SCD, and SGDS customers using between 6,440 and 64,400 therms annually from $48.00 to $55.50 per month (Columbia Ex. No. 103, Sch. 8, p. 6, lns. 13-14).

Q. WHAT IS THE COMPANY'S CLAIMED BASIS FOR ITS PROPOSED CUSTOMER CHARGES FOR THE SGSS, SCD, AND SGDS CLASSES?

A. The claimed basis for its proposed SGSS, SCD, and SGDS customer charges is the Company's over-inclusive customer cost analysis.

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE LEVEL OF CUSTOMER CHARGE FOR THE SGSS, SCD, AND SGDS CLASSES USING LESS THAN 6,440 THERMS ANNUALLY?

A. As described above, my customer cost analysis shows that the Company incurs approximately $23.36 per month in direct and indirect SGSS, SCD, and SGDS class customer costs to provide service. There is no cost basis for increasing the present customer charges for SGSS, SCD, and SGDS customers using less than 6,440 therms annually from $21.25 to $27.75 per month. Therefore, I recommend that the present $21.25 per month customer charge for SGSS, SCD, and SGDS class customers using less than 6,440 therms annually should not be increased by more than $2.11 per month ($23.36 - $21.25).

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE LEVEL OF CUSTOMER CHARGE FOR THE SGSS, SCD, AND SGDS CLASSES USING BETWEEN 6,440 AND 64,400 THERMS ANNUALLY?

A. I recommend that the present $48.00 per month customer charge for SGSS, SCD, and SGDS class customers using between 6,440 and 64,400 therms annually remain at its current level. Keeping the customer charge at a level that customers are familiar with paying still exceeds the $23.36 per month in customer costs incurred by this class in order for Columbia to provide them with service.

Q. DESCRIBE COLUMBIA'S RESIDENTIAL WNA?

A. Columbia's three year pilot residential WNA, which began in October 2013, is a temperature-based weather normalization mechanism that permits the Company to calculate the non-gas portion of customers' bills based upon normal weather.

Q. HAS THE COMMISSION IMPOSED ANY REPORTING REQUIREMENTS RELATED TO THE COMPANY'S THREE-YEAR PILOT RESIDENTIAL WNA?

A. Yes. The Joint Petition for Settlement filed by the parties to the prior proceeding at Docket No. R-2012-2321748, and as approved by the Commission, required that Columbia provide to the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate, on or before October 1, 2014, all reports and records supporting the operation of its WNA for the preceding year.

The residential WNA has been in effect since October 2013. During the course Company's prior base rate proceeding at Docket No. R-2014-2406274, Company witness Kempic discussed the resulting effect of the WNA during its inaugural winter (2013-2014). Mr. Kempic indicated on page 11 of Columbia Statement No. 1 that during the months of November 2013, January 2014, and February 2014 Columbia's residential customers have been credited $4,456,028 in distribution costs as a result of the WNA and the colder than normal weather from November 2013 through February 2014. Additionally, Columbia's website indicates that a customer savings during the period of November 2014 through February 2015 of approximately $3.8 million is attributable to the WNA.[2]

CHOICE ADMINISTRATION CHARGE RIDER ("RIDER CAC")

Q. WHAT IS THE INTENDED PURPOSE OF THE COMPANY'S PROPOSED RIDER CAC?

A. The intended purpose of Rider CAC is to isolate and unbundle costs incurred by Columbia that relate to the Company's cost in administering transportation services on behalf of its customers. In addition to incurring costs associated with the distribution of natural gas from city gates to customer delivery points, the Company incurs costs associated with procuring natural gas supplies for its sales customers and maintaining and administering activities associated with its end-use customers' transportation service (includes both Choice and General Distribution Service ("GDS"). Columbia indicates that because the Commission has required unbundling of the expenses Columbia incurs to procure natural gas supplies on behalf of its sales customers through its Rider GPC, expenses incurred to administer and maintain transportation services should also be unbundled and reflected as a separate non-reconcilable rider, Rider CAC (Columbia St. No. 12, pp. 6-7). Company witness Krajovic explains that Rider CAC merely assigns the costs required to make available the Choice program to Choice customers.

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[2] https://www.columbiagaspa.com/billing-payment-options/rate-adjustment-information/rate-adjustment-faq

Q. WHAT RATE SCHEDULES DOES COLUMBIA PROPOSE BE SUBJECT TO RIDER CAC?

A. Columbia is proposing that all transportation rate schedules, including Residential Distribution Service ("RDS"), Small Commercial Distribution ("SCD"), Small General Distribution Service ("SGDS"), Small Distribution Service ("SDS"), Large Distribution Service ("LDS"), and Main Line Distribution Service ("MLDS") be subject to Rider CAC.

Columbia proposes to recover the total Choice and GDS program costs by billing the Rider CAC two different ways. Rider CAC is proposed to be applied to Choice Service customers through the usage based Pass-through Charge on each bill and to GDS customers through a fixed charge labeled "Choice Administration Charge" on each bill (Columbia Ex. No. 14, Sch. 2, Attachment 2, Thirteenth Revised Tariff Page No. 164). The Rider CAC rate that is applicable to rate schedules RDS and SCD is $0.00499 per therm, and the Rider CAC fixed charge for rate schedules SGDS, SDS, LDS, and MLDS is $13.67 per account per bill (Columbia St. No. 12, p. 6).

Q. DOES THE COMPANY CURRENTLY RECOVER THROUGH DISTRIBUTION RATES COSTS THAT COLUMBIA IS INCLUDING IN RIDER CAC?

A. Yes. However, as part of the rate design proposed in this case the Company has deducted these costs from the Company's base distribution revenue requirement and calculated proposed distribution rates on this adjusted base distribution revenue requirement.

Q. WHAT ARE THE COSTS INCURRED BY THE COMPANY THAT ARE PROPOSED TO BE RECOVERED THROUGH RIDER CAC?

A. Rider CAC is designed to recover expenses the Company incurs solely to administer, enhance, and maintain gas transportation programs (Columbia St. No. 12, p. 7). More specifically, Rider CAC includes labor costs for employees whose job responsibilities are directly impacted by the Choice Program and GDS, and IT programming costs the Company incurs to enhance and maintain the systems that support the Choice Program and GDS (Columbia St. No. 12, p. 8).

Q. DO YOU AGREE WITH THE COMPANY'S RATIONALE FOR PROPOSING RIDER CAC?

A. No. It is not appropriate to recover CAC costs solely from Choice customers. Ms. Krajovic claims that "Columbia's Sales Service customers are currently paying for the administration and maintenance of programs for which they receive no benefit." This statement is incorrect. By having Choice programs in place and available, all customers benefit, including Sales Service customers, should they decide to participate. Under the Company's proposal, Choice and transportation customers would pay for these programs to have them available for Columbia's Sales Service customers when such customers decide to participate. This penalizes those who exercise Choice participation or use transportation distribution service.

Q. MS. KRAJOVIC BELIEVES THAT ESTABLISHING A NEW RIDER TO PLACE COSTS ON TRANSPORTATION CUSTOMERS IS IN THE INTEREST OF UNBUNDLING RATES, SPECIFICALLY THE UNBUNDLING OF COSTS UNDERLYING THE GAS PROCUREMENT CHARGE, AS INITIATED IN DOCKET NO. L-2008-2069114. IS THAT ACCURATE?

A. No. The purpose of that docket was to promote effective competition for natural gas supply. There is a distinction between the cost allocated to the GPC and the costs allocation Columbia is proposing in Rider CAC. The GPC is designed to allocate costs of services for sales customers that are being recovered through distribution rates that NGSs are already providing to Choice customers. However, the costs Columbia is attempting to charge through Rider CAC are simply costs required to make Choice products available to customers.

Because promotion of Choice and improvement of the competitive gas supply market in Pennsylvania is a stated goal of the Commission, the Company should not be proposing a new rider to increase the costs of transportation customers and provide a disincentive to Choice. The Commission gave just the opposite direction when it mandated the establishment of the GPC so that the costs associated with those areas of the LDC that were used in the provision of gas supply services would be properly recovered from just the customers that receive gas supply from the Company.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

JEREMY B. HUBERT

PROFESSIONAL EXPERIENCE AND EDUCATION

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Mechanical Engineering, 2003

- Attended EUCI Introduction to Rate Design for Electric Utilities, Philadelphia, PA, 2007
- Attended EUCI Introduction to Cost of Service Concepts and Techniques for Electric Utilities, Philadelphia, PA, 2007
- Attended NARUC Rate School, San Diego, CA, 2008
- PUC Gas Safety Seminar, 2008
- Participated in the NARUC sponsored PUC partnership with the country of Kosovo. This three year partnership between the PUC and Kosovo to initially assist them in the review and development of retail electricity tariffs commenced with a trip to Kosovo the first full week of November 2013 and consisted of several days of meetings and discussions with Kosovo's Energy Regulatory Office (ERO) in Pristina, the capital, 2013

EXPERIENCE:

11/2006 - Present

Bureau of Investigation and Enforcement (f/k/a Office of Trial Staff), Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Review and analyze financial, economic, and engineering records and testimony which are submitted by jurisdictional utilities in order for them to justify proposed changes in tariffed rates, and to identify any issues regarding revenues, the cost of service, rate design, rate base, 1307(f) gas costs and quality of service.

Technical review of base rate filings may include analysis of depreciation studies, examination of income statements, including (but not limited to) the operating revenue accounts and adjustments thereto, in order to determine whether the utility's revenues based on normalized sales volumes are reasonable for ratemaking purposes, analysis of bill frequency analyses and proofs of revenue in order to determine the appropriateness of the utility's customer classifications in rate design, performing bill comparisons at present and proposed rates, or analysis of cost of service studies in order to determine the reasonableness of a utility's allocation methodology of costs to the various customer classes, and whether a rate increase has been distributed among those customer classes in a fair and reasonable manner.

Additional duties include attending prehearing and settlement conferences, responding orally to cross examination questions in formal rate hearings, providing technical assistance to attorneys in the preparation of briefs, review of company and complainant briefs and reply briefs, and review of ALJ recommended decisions and exceptions and reply exceptions to ALJ recommended decisions.

10/2005 – 11/2006

Pennsylvania Department of Transportation - Harrisburg, Pennsylvania

Materials Technician – Responsible, primarily, for performing a variety of technical duties associated with the routine testing of coarse aggregates according to AASHTO and PTMs.

05/2005 – 10/2005

Gatter & Diehl, Inc. Consulting Engineers - Harrisburg, Pennsylvania

Mechanical Designer – Responsible, primarily, for assisting engineers and CADD technicians in the design aspects of HVAC, plumbing, and fire protection systems.

TESTIMONY SUBMITTED:

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

- Village Water Company, Docket No. R-00072351
- United Water of Pennsylvania, Inc., Docket No. A-210013F0017
- Total Environmental Solutions, Inc.
  Treasure Lake Division, Docket No. R-00072493
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,
  Docket No. R-2008-2012502
- PECO Energy Company, Docket No. R-2008-2028394
- PPL Gas Utility Corporation, 1307(f) proceeding,
  Docket No. R-2008-2039634
- Newtown Artesian Water Company, Docket No. R-2008-2042293
- Equitable Gas Company, Docket No. R-2008-2029325
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,

Docket No. R-2009-2083181

- Columbia Gas of Pennsylvania, 1307(f) proceeding, Docket No. R-2009-2093219
- UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2009-2105909
- Pennsylvania American Water Company, Docket No. R-2009-2097323
- PPL Electric, Energy Efficiency and Conservation Plan, Docket No. M-2009-2093216
- Utilities, Inc. of Pennsylvania, Docket No. R-2009-2117402
- Aqua Pennsylvania, Inc., Docket No. R-2009-2132019
- Newtown Artesian Water Company, Docket No. R-2009-2117550
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2009-2149262
- National Fuel Gas Distribution Corporation, 1307(f) proceeding, Docket No. R-2010-2150861
- T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797
- Columbia Gas of Pennsylvania, 1307(f) proceeding, Docket No. R-2010-2161920
- UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
- Total Environmental Solutions, Inc. Treasure Lake Water Division, Docket No. R-2010-2171918
- Total Environmental Solutions, Inc. Treasure Lake Sewer Division, Docket No. R-2010-2171924
- Wellsboro Electric Company, Docket No. R-2010-2172662
- Columbia Gas of Pennsylvania, Inc., Docket Nos. R-2010-2215623 R-2010-2201974
- Columbia Gas of Pennsylvania, Inc., 1307(f) proceeding Docket No. R-2011-2228696
- The Newtown Artesian Water Company, Docket Nos. R-2010-2215623 R-2010-2201974
- United Water Pennsylvania, Inc. Docket No. R-2011-22332985
- Aqua Pennsylvania, Inc., Docket No. R-2011-2267958
- PECO Energy Company – Gas Division, 1307(f) proceeding, Docket No. R-2012-2302784
- PPL Electric Utilities Corporation, Docket No. R-2012-2290597
- Columbia Gas of Pennsylvania, Inc., Docket Nos. R-2012-2321748 M-2012-2323645
- Columbia Gas of Pennsylvania, Inc., 1307(f) proceeding Docket No. R-2013-2351073
- Peoples TWP LLC, Docket No. R-2013-2355886
- Duquesne Light Company, Docket No. R-2013-22372129

- National Fuel Gas Distribution Corporation, 1307(f) proceeding, Docket No. R-2014-2399610
- City of Bethlehem – Bureau of Water, Docket No. R-2013-2390244
- Columbia Gas of Pennsylvania, Inc. 1307(f) proceeding, Docket No. R-2014-2408268
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2014-2406274
- PECO Energy Company, 1307(f) proceeding, Docket No. R-2014-2420283
- Duquesne Light Company, Default Service Plan Docket No. P-2014-2418242
- West Penn Power Company, Docket No. R-2014-2428742
- West Penn Power Company, Docket No. M-2013-2341991
- Pennsylvania Electric Company, Docket No. R-2014-2428743
- Pennsylvania Electric Company, Docket No. M-2013-2341994
- Pennsylvania Power Company, Docket No. R-2014-2428744
- Pennsylvania Power Company, Docket No. M-2013-2341993
- Metropolitan Edison Company, Docket No. R-2014-2428745
- Metropolitan Edison Company, Docket No. M-2013-2341990

I&E Exhibit No. 3
Witness: Jeremy B. Hubert
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Exhibit to Accompany

the

Direct Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:
Test Year
Rate Base
Present Rate Revenues
Cost of Service
Scaleback
Customer Cost Analysis
Customer Charges
CAC Rider

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RS

Question No. I&E-RS-26-D:

Reference Columbia Statement No. 1, page 16, lines 3-11. Provide the additional level of revenue deficiency associated solely with the inclusion of the fully projected future test year ending December 31, 2016 compared to a future test year ending November 30, 2015. Include all assumptions used.

Response:

The additional level of revenue deficiency associated solely with the inclusion of the fully projected future test year, or fully forecasted rate year ("FFRY") is $23,791,370.

Please refer to I&E-RS-26-D Attachment A, which details the calculation.

There are several claim adjustments that are included in the FFRY revenue requirement filed in this case that would have been included as part of the future test year (FTY) had this case been filed under the pre-Act 11 rules. The adjustments are:

- Tax Refund Amortization – change in the refund as described in Witness Fischer's testimony (Statement No. 10).
- Labor for Safety, Front Line Leaders, Damage Prevention Coordinators, Restoration, etc. – Witness Davidson (Statement No. 15) discusses these items.
- Increased O&M Safety Initiatives – Witness Davidson (Statement No. 15) and Witness Kempic (Statement No. 1) describes these expenses.
- Increased O&M for Training – the proposed recovery of this expense is discussed by Witness Davidson (Statement No. 15) and Witness Kempic (Statement No. 1).
- Emergency Repair Program Adjustment – Witness Krajovic (Statement No. 12) proposes the recovery of this adjustment.

- Rider Customer Choice - Witness Krajovic (Statement No. 12) also proposes the recovery of this adjustment.

Under the pre-Act 11 filing rules, the Company would have filed a revenue requirement of $22,381,113 (Attachment, Line 23). The difference between this revenue requirement deficiency and the as filed revenue requirement deficiency of $46,172,483 reflects the $23,791,370 impact of the FFRY.

Columbia Gas of Pennsylvania
Revenue Requirement with FTY ended November 30, 2015

Description (A)	Reference (B)	(C)	(D)	(E)	(F)
ure Test Year Rate Base	Exh. 102, Sch 3, Pg 3, Col 2, Ln 28	1,182,458,138			
d for Return on Rate Base	Exh. 102, Sch 3, Pg 3, Col 6, Ln 25	8.14%			
erating Income Requirement	Line 1 x Line 2		96,252,092		
Operating Income @ Present Rates	Exh. 102, Sch 3, Pg 3, Col 2, Ln 26		87,187,993		
erating Income Deficiency before Adjustments	Line 3 - Line 4		9,064,099		
enue Conversion Factor	Exh. 102, Sch 3, Pg 5, Ln 18		1.67602331		
Revenue Requirement Before Adjustments	Line 5 x Line 6			15,191,642	
ustments To FTY as filed;					
Refund Amortization	Exh. 107, Pg 8, Col 2, Ln 19	908,760			
enue Conversion Factor	Exh. 102, Sch 3, Pg 5, Ln 17	1.67602331			
Tax Refund - Revenue Requirement Impact	Line 9 x Line 10		1,523,103		
or - Includes positions related to safety, damage prevention, restoration, etc.	Exh. 104, Sch 10, Pg 2	1,223,720			
side Services - Safety Initiatives	Exh. 104, Sch 11, Pg 2	813,000			
ts & Leases - CPA Training Center	Exh. 104, Sch 12, Pg 2	602,000			
C - Shared NGD Operations - O&M for Training & Safety Initiatives	Exh. 104, Sch 14, Pg 2	2,880,000			
ergency Repair Program Adjustment	Exh. 104, Sch 2, Pg 24, Ln 2	100,000			
er Customer Choice Adjustment	Exh. 104, Sch 2, Pg 24, Ln 1	47,648			
Total O&M Adjustments	Line 12 thru 17		5,666,368		
enue Requirement Impact of all FTY Adjustments	Line 11 + Line 18			7,189,471	
ure Test Year Revenue Requirement with Adjustments	Line 7 + Line 19				22,381,113
y Forecasted Rate Year Revenue Requirement	Exh. 102, Sch 3, Pg 3, Col 5, Ln 13				46,172,483
itional level of Revenue Deficiency associated with usion of Fully Forecasted Rate Year	Line 21 - Line 20				23,791,370

Docket No. R-2015-2468056

		Additions					Retirements				
		Actuals (A)	Difference (B)=(A)-(C)	Projected (As Filed) R-2012-2321748 (C)	Difference (D)=(A)-(E)	Projected (As Filed) R-2014-2406274 (E)	Actuals (F)	Difference (G)=(F)-(H)	Projected (As Filed) R-2012-2321748 (H)	Difference (I)=(F)-(J)	Projected (As Filed) R-2014-2406274 (J)
1	June 2012	$12,830,640		$14,977,300			($1,789,253)		($1,123,800)		
2	July 2012	$13,399,498		$14,625,000			($795,189)		($1,097,300)		
3	August 2012	$13,330,210		$14,080,400			($990,099)		($1,056,500)		
4	September 2012	$12,021,735		$15,502,003			($1,080,577)		($2,172,923)		
5	October 2012	$19,421,418		$14,202,500			($1,616,986)		($1,065,600)		
6	November 2012	$16,233,971		$13,034,000			($1,753,984)		($978,000)		
7	December 2012	$17,662,571		$9,945,400			($1,887,668)		($746,200)		
8	January 2013	$4,295,938		$8,435,500			($930,082)		($632,900)		
9	February 2013	$4,750,867		$8,151,300			($985,149)		($611,600)		
10	March 2013	$7,841,469		$11,422,000			($849,593)		($857,000)		
11	April 2013	$11,183,587		$13,705,300			($1,639,073)		($1,028,300)		
12	May 2013	$13,646,074		$15,047,800			($587,396)		($1,918,445)		
13	June 2013	$18,014,081		$15,986,900			($841,349)		($1,199,500)		
14	TOTAL (June 2012 -June 2013)	$164,632,059	($4,483,344) 2.7%	$169,115,403			($15,746,398)	($1,258,330) 8.7%	($14,488,068)		
15	July 2013	$12,189,097		$16,104,400			($1,364,184)		($1,208,300)		
16	August 2013	$9,646,654		$16,230,100			($1,076,747)		($1,217,800)		
17	September 2013	$25,813,963		$16,452,100			($1,361,009)		($1,234,000)		
18	October 2013	$21,405,454		$16,412,800			($1,889,711)		($1,231,500)		
19	November 2013	$17,532,204		$13,837,400			($1,985,513)		($1,038,200)		
20	December 2013	$17,324,918		$14,390,700			($2,922,262)		($1,079,700)		
21	January 2014	$3,388,088		$8,581,500		$7,993,800	($641,155)		($643,900)		($602,500)
22	February 2014	$7,263,737		$8,297,300		$7,412,300	($866,639)		($622,600)		($805,500)
23	March 2014	$9,135,521		$11,549,300		$11,753,500	($610,510)		($866,600)		($1,352,500)
24	April 2014	$27,968,120		$17,888,300		$20,686,000	($1,562,743)		($1,342,200)		($1,591,200)
25	May 2014	$23,464,309		$15,024,800		$13,219,500	($1,222,338)		($1,127,300)		($996,600)
26	June 2014	$30,845,196		$16,132,900		$21,088,400	($1,182,562)		($3,428,530)		($1,589,600)
27	TOTAL (July 2013 - June 2014)	$205,977,262	$35,075,662 20.5%	$170,901,600			($16,685,373)	($1,644,743) 10.9%	($15,040,630)		
28	July 2014	$11,383,938				$15,639,300	($1,250,479)				($1,178,900)
29	August 2014	$17,423,763				$19,554,900	($1,143,895)				($1,473,900)
30	September 2014	$14,107,571				$26,968,100	($1,746,571)				($2,032,700)
31	October 2014	$20,168,006				$17,405,500	($2,496,311)				($1,312,100)
32	November 2014	$24,917,322				$14,176,800	($1,517,403)				($2,325,942)
33	December 2014	$13,348,436				$15,924,300	($2,988,622)				($3,339,691)
34	TOTAL (January 2014 - December 2014)	$203,414,006			$11,591,606 6.04%	$191,822,400	($17,229,227)			$1,371,906 7.38%	($18,601,133)
35	January 2015	$1,718,523			($6,024,877)	$7,743,400	($919,579)			($333,579)	($586,000)
36	February 2015	$4,688,425			($2,280,075)	$6,968,500	($351,134)			$170,566	($521,700)
37	March 2015	Not Available				$11,595,500	Not Available				($890,200)
38	April 2015	Not Available				$12,455,300	Not Available				($932,000)
39	May 2015	Not Available				$12,459,600	Not Available				($929,700)
40	June 2015	Not Available				$20,920,200	Not Available				($1,571,300)
41	July 2015	Not Available				$15,915,300	Not Available				($1,193,500)
42	August 2015	Not Available				$21,437,700	Not Available				($1,606,700)
43	September 2015	Not Available				$17,935,800	Not Available				($1,345,800)
44	October 2015	Not Available				$15,824,700	Not Available				($1,183,300)
45	November 2015	Not Available				$14,133,500	Not Available				($1,085,700)
46	December 2015	Not Available				$21,261,400	Not Available				($3,996,439)
47	TOTAL (January 2015 - December 2015)					$178,650,900					($15,842,389)

I&E Exhibit No. 3
Schedule 2

I&E Exhibit No. 3
Schedule 3

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended November 30, 2014

Line	Description	Bills	Total Normal Usage (Dth/cust.)	Total Consumption (Dth)	Base Rate ($/Dth)	Revenue ($)
		Columbia Ex 103 Schedule No. 1 Docket No. R-2014-2406274		*Columbia Ex 103 Schedule No. 1 Docket No. R-2014-2406274*		
		(A)	(B)	(C)	(D)	(E)
1	**Rate Schedule RSS - Residential Sales Service**					
2		273,064 customers	83.86	22,898,207.0		
3	Customer Charge	3,317,995			16.75	55,576,416
4	Commodity Charge:					
5	All Gas Consumed			22,898,207.0	3.5017	80,182,651
6	Rider USP - Universal Service Plan			22,898,207.0	0.6188	14,169,410
7	Rider CC - Customer Choice			22,898,207.0	0.0000	0
8	Gas Procurement Charge			22,898,207.0	0.0535	1,225,054
9	Subtotal					151,153,531
0	STAS					93,715
1	Base Rate Revenue					151,247,246
2	Gas Cost			22,898,207.0	5.5316	126,663,722
3	Merchant Function Charge			22,898,207.0	0.0706	1,616,613
4	Total Rate Schedule RSS	3,317,995		22,898,207.0		279,527,581
5	**Rate Schedule RDS - Residential Distribution Service (Choice)**					
6		89,902 customers	90.46	8,132,569.4		
7	Customer Charge	1,079,897			16.75	18,088,275
8	Commodity Charge:					
	All Gas Consumed			8,132,569.4	3.5017	28,477,818
	Rider USP - Universal Service Plan			8,132,569.4	0.6188	5,032,434
	Rider CC			8,132,569.4	0.0000	0
2	Choice Administration Charge			8,132,569.4	0.0000	0
3	Subtotal					51,598,527
	STAS					31,991
5	Base Rate Revenue					51,630,518
5	Gas Cost			8,132,569.4	0.7996	6,502,802
7	Total Rate Schedule RDS	1,079,897		8,132,569.4		58,133,320
3	**Rate Schedule RCC - Residential Distribution Service (CAP)**					
		20,610 customers	120.84	2,490,430.7		
	Customer Charge	249,716			16.75	4,182,743
	Commodity Charge:					
	All Gas Consumed			2,490,430.7	3.5017	8,720,741
	Subtotal			2,490,430.7		12,903,484
	STAS					8,000
	Base Rate Revenue					12,911,484
	Gas Cost			2,490,430.7	0.7996	1,991,348
	Total Rate Schedule RCC	249,716		2,490,430.7		14,902,832
	Total Residential	383,576 customers	87.39	33,521,207.1		

Columbia Gas of Pennsylvania, Inc.
Customers by Rate Schedule
For the Periods 2015 and 2016

Line No.	Description	Nov. 15 (1)	Dec. 15 (2)	Dec. 16 (3)
1	**Rate Schedule RSS - Residential Sales Service**			
2	Rate Schedule RSS	274,429	274,397	277,778
3	**Rate Schedule RDGSS - Residential Distributed Generation Sales Service**			
4	Rate Schedule RDGSS	20	22	22
5	**Rate Schedule SGSS - Small General Sales Service**			
6	Less Than 6,440 Therms Annually	23,483	23,147	23,214
7	6,440 - 64,400 Therms Annually	3,135	3,261	3,261
8	Total Rate Schedule SGSS	26,618	26,408	26,475
9	**Rate Schedule NSS - Negotiated Sales Service**			
10	Less Than 6,440 Therms Annually	0	0	0
11	6,440 - 64,400 Therms Annually	0	0	0
12	> 64,400 to ≤ 110,00 Therms Annually	0	0	0
13	>110,000 to ≤ 540,000 Therms Annually	0	0	0
14	>540,000 to ≤ 1,074,000 Therms Annually	1	1	1
15	Total Rate Schedule NSS	1	1	1
16	**Rate Schedule LGSS - Large General Sales Service**			
17	> 64,400 to ≤ 110,000 Therms Annually	42	42	42
18	>110,000 to ≤ 540,000 Therms Annually	33	33	33
19	>540,000 to ≤ 1,074,000 Therms Annually	2	2	2
20	>1,074,000 to ≤ 3,400,000 Therms Annually	0	0	0
21	>3,400,000 to ≤ 7,400,000 Therms Annually	0	0	0
22	> 7,400,000 Therms Annually	0	0	0
23	Total Rate Schedule LGSS	77	77	77

24	**Tariff Sales Summary by Customer Class**			
25	Total Residential Sales	274,449	274,419	277,800
26	Total Small General Service Sales Sales	26,618	26,408	26,475
27	Total Negotiated Sales Service	1	1	1
28	Total Large General Service Sales	77	77	77
29	Total Tariff Sales	301,145	300,905	304,353

Columbia Gas of Pennsylvania, Inc.
Customers by Rate Schedule
For the Periods 2015 and 2016

Line No.	Description	Nov. 15 (1)	Dec. 15 (2)	Dec. 16 (3)
1	**Rate Schedule RDS - Residential Distribution Service (Choice)**			
2	Total Rate Schedule RDS	87,583	89,526	90,355
3	**Residential Distribution Service (CAP)**			
4	Rate Schedule RCC	21,640	19,689	19,872
5	**Rate Schedule RDGDS - Residential Distributed Generation Distribution Service (Choice)**			
6	Total Rate Schedule RDGDS	6	6	6
7	**Rate Schedule SCD - Small Commercial Distribution (Choice)**			
8	Total Rate Schedule SCD	8,261	8,308	8,327
9	**Rate Schedule SGDS - Small General Distribution Service**			
10	Less Than 6,440 Therms Annually	652	652	652
11	6,440 - 64,400 Therms Annually	1,598	1,598	1,598
12	Flex	9	9	9
13	Total Rate Schedule SGDS	2,259	2,259	2,259
14	**Rate Schedule SDS - Small Distribution Service**			
15	> 64,400 to ≤ 110,00 Therms Annually	175	175	175
16	>110,000 to ≤ 540,000 Therms Annually	208	208	208
17	Flex	9	9	9
18	Total Rate Schedule SDS	392	392	392
19	**Rate Schedule LDS - Large Distribution Service**			
20	> 540,000 to <= 1,074,000 Therms Annually	47	47	46
21	> 1,074,000 to <= 3,400,000 Therms Annually	27	27	27
22	> 3,400,000 to <= 7,500,000 Therms Annually	4	4	4
23	> 7,500,000 Therms Annually	1	1	1
24	Flex	19	19	19
25	Total Rate Schedule LDS	98	98	97

Columbia Gas of Pennsylvania, Inc.
Customers by Rate Schedule
For the Periods 2015 and 2016

Line No.	Description	Nov. 15 (1)	Dec. 15 (2)	Dec. 16 (3)
1	**Rate Schedule MLDS - Main Line Distribution Service - Class I**			
2	> 274,000 to <= 540,000 Therms Annually	0	0	0
3	> 540,000 to <= 1,074,000 Therms Annually	3	3	3
4	> 1,074,000 to <= 3,400,000 Therms Annually	0	0	0
5	> 3,400,000 to <= 7,500,000 Therms Annually	0	0	0
6	> 7,500,000 Therms Annually	0	0	0
7	Flex	1	1	1
8	Total Rate Schedule MLDS - Class I	4	4	4
9	**Rate Schedule MLDS - Main Line Distribution Service - Class II**			
10	> 274,000 to <= 540,000 Therms Annually	0	0	0
11	> 540,000 to <= 1,074,000 Therms Annually	0	0	0
12	> 1,074,000 to <= 3,400,000 Therms Annually	1	1	1
13	> 3,400,000 to <= 7,500,000 Therms Annually	0	0	0
14	> 7,500,000 Therms Annually	0	0	0
15	Flexed	5	5	5
16	Total Rate Schedule MLDS - Class II	6	6	6
17	**Distribution Service Summary by Customer Class**			
18	Total Residential Distribution Service	109,229	109,221	110,233
19	Total Small Distribution Service (SCD, SGDS, SDS)	10,912	10,959	10,978
20	Total Large Distribtuion Serivce	98	98	97
21	Total Mainline Distribtuion Serivce	10	10	10
22	Total Distribution Service	120,249	120,288	121,318
23	**Total Company**	**421,394**	**421,193**	**425,671**

Residential Customers
For the Twelve Months Ending December 31, 2016

Line No.	Description	Per Company (A) Bills	(B) Total Normal Usage (Dth/cust.)	(C) Total Consumption (Dth)	(D) Base Rate ($/Dth)	(E) Revenue ($)	(F) Increase to Present Rate Revenues ($)	Per BI&E (G) Bills	(H) Total Normal Usage (Dth/cust.)	(I) Total Consumption (Dth)	(J) Base Rate ($/Dth)	(K) Revenue ($)
		Columbia Ex 103 Schedule No. 1		*Columbia Ex 103 Schedule No. 1*								
1	Rate Schedule RSS - Residential Sales Service											
2		277,800 customers	83.80	23,280,676.1				277,800 customers	91.47	25,409,026.4		
3	Customer Charge	3,377,134			16.75	56,566,995		3,377,134			16.75	56,566,995
4	Commodity Charge:											
5	All Gas Consumed			23,280,676.1	4.2138	98,100,113	$8,968,442			25,409,026.4	4.2138	107,068,555
6	Rider USP - Universal Service Plan			23,280,676.1	0.8800	20,486,995				23,280,676.1	0.8800	20,486,995
7	Rider CC - Customer Choice			23,280,676.1	0.0009	20,953				23,280,676.1	0.0009	20,953
8	Gas Procurement Charge			23,280,676.1	0.0695	1,618,007	$147,920			25,409,026.4	0.0695	1,765,927
9	Subtotal					176,793,063						185,909,425
10	STAS					0						0
11	Base Rate Revenue					176,793,063						185,909,425
12	Gas Cost			23,280,676.1	5.3891	125,461,892	$11,469,892			25,409,026.4	5.3891	136,931,784
13	Merchant Function Charge			23,280,676.1	0.0676	1,573,774	$143,876			25,409,026.4	0.0676	1,717,650
14	Total Rate Schedule RSS	3,377,134		23,280,676.1		303,828,729		3,377,134				324,558,859
15	Rate Schedule RDS - Residential Distribution Service (Choice)											
16		90,361 customers	90.02	8,134,026.3				90,361 customers	90.02	8,134,026.3		
17	Customer Charge	1,069,855			16.75	17,920,071		1,069,855			16.75	17,920,071
18	Commodity Charge:											
19	All Gas Consumed			8,134,026.3	4.2138	34,275,160				8,134,026.3	4.2138	34,275,160
20	Rider USP - Universal Service Plan			8,134,026.3	0.8800	7,157,943				8,134,026.3	0.8800	7,157,943
21	Rider CC			8,134,026.3	0.0009	7,321				8,134,026.3	0.0009	7,321
22	Choice Administration Charge			8,134,026.3	0.0000	0				8,134,026.3	0.0000	0
23	Subtotal					59,360,495						59,360,495
24	STAS					0						0
25	Base Rate Revenue					59,360,495						59,360,495
26	Gas Cost			8,134,026.3	0.7266	5,910,184				8,134,026.3	0.7266	5,910,184
27	Total Rate Schedule RDS	1,069,855		8,134,026.3		65,270,679		1,069,855		8,134,026.3		65,270,679
28	Rate Schedule RCC - Residential Distribution Service (CAP)											
29		19,872 customers	126.46	2,512,973.7				19,872 customers	126.46	2,512,974		
30	Customer Charge	257,325			16.75	4,310,194		257,325			16.75	4,310,194
31	Commodity Charge:											
32	All Gas Consumed			2,512,973.7	4.2138	10,589,169				2,512,973.7	4.2138	10,589,169
33	Subtotal			2,512,973.7		14,899,363				2,512,973.7		14,899,363
34	STAS					0						0
35	Base Rate Revenue					14,899,363						14,899,363
36	Gas Cost			2,512,973.7	0.7266	1,825,927				2,512,973.7	0.7266	1,825,927
37	Total Rate Schedule RCC	257,325		2,512,973.7		16,725,290		257,325		2,512,973.7		16,725,290
38	**Total Residential**	388,033 customers	87.44	33,927,676.1		385,824,698	$20,730,130	388,033 customers	92.92	36,056,026		406,554,828

I&E Exhibit No. 3
Schedule 5

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RS

Question No. I&E-RS-1-D:

Reference Columbia Statement No. 2, p. 14, and the Company's description of the residential annual Dth per customer. For each data point depicted on the graph, provide the annual Dth per residential customer.

Response:

See I&E-RS-1-D Attachment A.

	Columbia Gas of Pennsylvania Residential Annual Dth per Customer Normalized for Weather
1991	117.9
1992	119.2
1993	118.6
1994	116.5
1995	114.8
1996	115.7
1997	112.3
1998	108.2
1999	106.6
2000	107.9
2001	106.5
2002	103.4
2003	103.4
2004	101.3
2005	96.0
2006	90.0
2007	92.6
2008	91.2
2009	89.0
2010	89.5
2011	89.0
2012	86.8
2013	90.1
TME Nov 2014	91.8
TME Jan 2015	91.0
TME Feb 2015	90.1
Future Test Year	88.2
Fully Forecasted Rate Year	87.4

Columbia Gas of Pennsylvania, Inc.
Residential Throughput Data
2003-2014
Docket No. R-2015-2468056

Normalized Usage per Customer

		(Dth)	Change
	(A)	(B)	(C)
1	2003	103.40	
			-2.10
2	2004	101.30	
			-5.30
3	2005	96.00	
			-6.00
4	2006	90.00	
			2.60
5	2007	92.60	
			-1.40
6	2008	91.20	
			-2.20
7	2009	89.00	
			0.50
8	2010	89.50	
			-0.50
9	2011	89.00	
			-2.20
10	2012	86.80	
			3.30
11	2013	90.10	
			1.70
12	TME November 2014	91.80	
13	SIX YEAR AVERAGE	Residential (Dth)	0.56
14	2015	92.36	
16	**December 2016**	**92.92**	

I&E Exhibit No. 3
Schedule 8

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2015-2468056
Summary of Increase to Present Rate Revenues Per BI&E
Fully Projected Future Test Year Ending December 31, 2016

	Customer Class	Company Claim	BI&E Proposed Adjustment	Adjusted Revenue Per BI&E
	(A)	(B) Co. Ex. No. 103 Schedule 1 pp. 13-18	(C)	(D)
	RESIDENTIAL CUSTOMERS			
	RSS - Residential Sales Service			
1	Non - Gas Revenues	$175,175,056	$8,968,442	$184,143,498
2	Gas Procurement Charge	$1,618,007	$147,920	$1,765,927
3	Merchant Function Charge	$1,573,774	$143,876	$1,717,650
4	Gas Costs	$125,461,892	$11,469,892	$136,931,784
5	STAS	$0	$0	$0
6	Total RSS Present Rate Revenue	$303,828,729	$20,730,130	$324,558,859
	RDS - Residential Distribution Service (Choice)			
7	Non - Gas Revenues	$59,360,495	$0	$59,360,495
8	Gas Costs	$5,910,184	$0	$5,910,184
9	STAS	$0	$0	$0
10	Total RDS Present Rate Revenue	$65,270,679	$0	$65,270,679
	RCC - Residential Distribution Service (CAP)			
11	Non - Gas Revenues	$14,899,363	$0	$14,899,363
12	Gas Costs	$1,825,927	$0	$1,825,927
13	STAS	$0	$0	$0
14	Total RCC Present Rate Revenue	$16,725,290	$0	$16,725,290
15	**Total Residential Present Rate Revenue (Lines 6+10+14)**	$385,824,698	$20,730,130	$406,554,828
16	**Total Residential Gas Cost (Lines 4+8+12)**	$133,198,003	$11,469,892	$144,667,895

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RS

Question No. I&E-RS-2-D:

Reference Columbia Standard Data Request, GASCOS No. 01-21, Volume 1, question COS-015, detailing the volumes and revenues from customers that pay less than the tariff (negotiated or market-based) rate for service. Provide a schedule in working Excel format with all formulas intact, providing the following details for each customer paying less than full tariff rates:

A. Name and account number;
B. Applicable rate schedule;
C. Reason for discount;
D. Annual customer charge;
E. Annual usage;
F. Annual usage charge;
G. Total bill;
H. Annual customer charge at full tariff rate;
I. Annual bill at full tariff rates;
J. Total bill at full tariff rate;
K. Annual discount off full tariff rates; and
L. Date the Company last verified the alternative.

Response:

A-L: Please see CONFIDENTIAL Attachment A to this response, which shows the annual usage for the twelve months ending November 30, 2014 priced out at the current effective rates. Note: While the data that Columbia provided in response to Standard Data Request COS-015 included prior period adjustments that occurred during the twelve months ended November 30, 2014, Attachment A does not include data regarding prior period adjustments.

HIGHLY CONFIDENTIAL

Customer (A)	Tariff (B)	Reason (C)	Current Customer Charge (D)	Annual Usage (E)	Current Usage Charge (F)	Total Bill (G)	Current Tariff Cust Chrg (H)	Bill at Tariff (I)	Total Bill at Tariff (J)	Annual Discount from Tariff (K)	Date Last Verified Alternative (L)
			$	Therms	$/Therm	$	$	$	$	$	
A											

3

[1] New flex as of 1/1/2014.

Columbia Gas of Pennsylvania, Inc.

Docket No. R-2015-2468056

Competitive Discount for

Bypass to LDC

Line	Rate Schedule	Total Annual Bill Under Discounted Tariff Rates	Total Annual Bill Under Full Tariff Rates	Discount Off Full Tariff Rates
	(A)	(B)	(C)	(D)
1				
27				
29	TOTAL	$1,171,157	$2,876,945	$1,705,788

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
I&E ALLOCATION OF RATE INCREASE TO CUSTOMER CLASSES UNDER COLUMBIA'S PROPOSED REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RSS/RDS (D) $	SGSS/SCD/SGDS (E) $	N/A (F) $	SDS/LGSS (G) $	LDS/LGSS (H) $	MLDS (I) $
1	TOTAL REVENUE [PAGE 6]		581,070,377	423,115,183	116,568,299	-	20,608,596	19,037,447	1,740,853
2	**I&E Recommended Revenue Re-allocation**		0	**(3,500,000)**	**2,700,000**	-	**800,000**	0	0
3			581,070,377	419,615,183	119,268,299	-	21,408,596	19,037,447	1,740,853
4	PRODUCTS PURCHASED [PAGE 7]		190,479,760	133,198,003	51,541,083	-	4,656,534	812,004	272,136
5	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		177,902,792	135,650,717	24,794,632	-	6,612,118	10,823,331	21,994
6	DEPRECIATION & AMORTIZATION [PAGE 5]		54,751,328	37,228,070	9,920,805	-	2,839,009	4,742,174	21,271
7	TAXES OTHER THAN INCOME [PAGE 9]		3,221,085	2,250,280	556,146	-	156,259	257,933	467
8	TOTAL EXPENSES & TAXES OTHER THAN INCOME		426,354,965	308,327,070	86,812,666	-	14,263,920	16,635,442	315,867
9	OPERATING INCOME BEFORE TAXES		154,715,412	111,288,113	32,455,632	-	7,144,676	2,402,005	1,424,985
10	INCOME TAXES		47,210,745	34,974,181	10,216,558	-	2,004,351	(570,896)	586,552
11	INVESTMENT TAX CREDIT	12	(360,240)	(238,789)	(67,235)	-	(20,159)	(33,938)	(119)
12	NET INCOME TAXES		46,850,505	34,735,393	10,149,322	-	1,984,192	(604,834)	586,433
13	OPERATING INCOME		107,864,907	76,552,721	22,306,310	-	5,160,485	3,006,839	838,552
14	RATE BASE [PAGE 10]		1,325,130,928	870,122,765	254,286,899	-	75,034,940	125,304,335	381,990
15	RATE OF RETURN EARNED ON RATE BASE		8.140%	8.798%	8.772%	0.000%	6.877%	2.400%	219.522%
16	UNITIZED RETURN		1.000	**1.080**	**1.080**	0.000	0.840	0.290	26.970

I&E Exhibit No. 3
Schedule 11

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2015-2468056
I&E Recommended Scale Back

	Total Scale Back Amount	Scale Back Allocation	RSS/RDS			SGSS/SCD/SGDS			SDS/LGS		
	(A)	(B)		(C)	(D)		(E)	(F)		(G)	(H)
			Scale Back		Relative Rate of Return	Scale Back		Relative Rate of Return	Scale Back		Relative Rate of Return
1	$500,000	100-0-0%	100%	$500,000	1.08	0%	$0	1.08	0%	$0	0.85
2	$1,000,000	100-0-0%	100%	$1,000,000	1.08	0%	$0	1.08	0%	$0	0.85
3	$1,500,000	100-0-0%	100%	$1,500,000	1.08	0%	$0	1.09	0%	$0	0.85
4	$1,600,000	80-20-0%	80%	$1,280,000	1.08	20%	$320,000	1.08	0%	$0	0.85
5	$2,000,000	80-20-0%	80%	$1,600,000	1.08	20%	$400,000	1.08	0%	$0	0.85
6	$4,000,000	80-20-0%	80%	$3,200,000	1.08	20%	$800,000	1.08	0%	$0	0.86
7	$6,000,000	80-20-0%	80%	$4,800,000	1.08	20%	$1,200,000	1.08	0%	$0	0.87
8	$8,000,000	80-20-0%	80%	$6,400,000	1.07	20%	$1,600,000	1.08	0%	$0	0.88
9	$10,000,000	77-23-0%	77%	$7,700,000	1.08	23%	$2,300,000	1.07	0%	$0	0.89
10	$12,000,000	77-23-0%	77%	$9,240,000	1.07	23%	$2,760,000	1.07	0%	$0	0.91
11	$14,000,000	77-23-0%	77%	$10,780,000	1.07	23%	$3,220,000	1.07	0%	$0	0.92
12	$16,000,000	77-23-0%	77%	$12,320,000	1.07	23%	$3,680,000	1.07	0%	$0	0.93
13	$18,000,000	77-23-0%	77%	$13,860,000	1.07	23%	$4,140,000	1.06	0%	$0	0.94
14	$20,000,000	77-23-0%	77%	$15,400,000	1.07	23%	$4,600,000	1.06	0%	$0	0.95
15	$22,000,000	77-23-0%	77%	$16,940,000	1.07	23%	$5,060,000	1.06	0%	$0	0.96
16	$24,000,000	77-23-0%	77%	$18,480,000	1.07	23%	$5,520,000	1.06	0%	$0	0.98
17	$26,000,000	77-23-0%	77%	$20,020,000	1.07	23%	$5,980,000	1.06	0%	$0	0.99
18	$28,000,000	77-23-0%	77%	$21,560,000	1.06	23%	$6,440,000	1.06	0%	$0	1.00
19	$30,000,000	77-22-1%	77%	$23,100,000	1.06	22%	$6,600,000	1.06	1%	$300,000	0.98
20	$32,000,000	77-22-1%	77%	$24,640,000	1.06	22%	$7,040,000	1.06	1%	$320,000	0.99
21	$34,000,000	77-22-1%	77%	$26,180,000	1.06	22%	$7,480,000	1.06	1%	$340,000	1.00
22	$38,000,000	77-22-1%	77%	$29,260,000	1.06	22%	$8,360,000	1.06	1%	$380,000	1.03
23	$40,000,000	77-22-1%	77%	$30,800,000	1.05	22%	$8,800,000	1.06	1%	$400,000	1.04
24	$40,258,200	77-22-1%	77%	$30,998,814	1.05	22%	$8,856,804	1.06	1%	$402,582	1.04
25			**Total SGSS/SCD/SGDS Increase** (I&E Recommended Allocation)				**$8,856,805**				

I&E Exhibit No. 3
Schedule 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ RE-ALLOCATED AND SCALED BACK RATES
I&E ALLOCATION OF RATE INCREASE TO CUSTOMER CLASSES UNDER COLUMBIA'S PROPOSED REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RSS/RDS (D) $	SGSS/SCD/SGDS (E) $	N/A (F) $	SDS/LGSS (G) $	LDS/LGSS (H) $	MLDS (I) $
1	TOTAL REVENUE [PAGE 6]		581,070,377	423,115,183	116,568,299	-	20,608,596	19,037,447	1,740,853
2	**I&E Recommended Revenue Re-allocation**			**(3,500,000)**	**2,700,000**		**800,000**		
	Scale Back Amount		**(40,258,200)**	**(30,998,814)**	**(8,856,804)**		**(402,582)**		
3			540,812,177	388,616,369	110,411,495	-	21,006,014	19,037,447	1,740,853
4	PRODUCTS PURCHASED [PAGE 7]		190,479,760	133,198,003	51,541,083	-	4,656,534	812,004	272,136
5	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		177,902,792	135,650,717	24,794,632	-	6,612,118	10,823,331	21,994
6	DEPRECIATION & AMORTIZATION [PAGE 5]		54,751,328	37,228,070	9,920,805	-	2,839,009	4,742,174	21,271
7	TAXES OTHER THAN INCOME [PAGE 9]		3,221,085	2,250,280	556,146	-	156,259	257,933	467
8	TOTAL EXPENSES & TAXES OTHER THAN INCOME		426,354,965	308,327,070	86,812,666	-	14,263,920	16,635,442	315,867
9	OPERATING INCOME BEFORE TAXES		114,457,212	80,289,299	23,598,828	-	6,742,094	2,402,005	1,424,985
10	INCOME TAXES		31,290,459	22,715,561	6,714,095	-	1,845,148	(570,896)	586,552
11	INVESTMENT TAX CREDIT	12	(360,240)	(238,789)	(67,235)	-	(20,159)	(33,938)	(119)
12	NET INCOME TAXES		30,930,219	22,476,772	6,646,859	-	1,824,989	(604,834)	586,433
13	OPERATING INCOME		83,526,993	57,812,527	16,951,969	-	4,917,105	3,006,839	838,552
14	RATE BASE [PAGE 10]		1,325,130,928	870,122,765	254,286,899	-	75,034,940	125,304,335	381,990
15	RATE OF RETURN EARNED ON RATE BASE		6.303%	6.644%	6.666%	0.000%	6.553%	2.400%	219.522%
16	UNITIZED RETURN		1.000	1.050	1.060	0.000	1.040	0.380	34.830
17	**Proposed Rate Revenue**		581,070,377	419,615,183	119,268,299	0	21,408,596	19,037,447	1,740,853
18	**Scale Back**		**(40,258,200)**	**(30,998,814)**	**(8,856,804)**	0	**(402,582)**	0	0
19			540,812,177	388,616,369	110,411,495	0	21,006,014	19,037,447	1,740,853
20	**Present Rate Revenue**		534,899,150	387,276,078	110,411,494	0	18,824,003	16,647,057	1,740,519
21	**Revenue Increase**		5,913,027	1,340,292	1	0	2,182,011	2,390,390	334
22	**Percent Increase**		1.11%	0.35%	0.00%		11.59%	14.36%	0.02%

I&E Exhibit No. 3
Schedule 13

CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION EXCLUDING MAINS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: B. E. ELLIOTT

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	RSS/RDS (E)	SGSS/SCD/SGDS (F)	N/A (G)	SDS/LGSS (H)	LDS/LGSS (I)	MLDS (J)
				$	$	$	$	$	$	$
1	874.00	MAINS & SERVICES [SERVICES ONLY][1]	15	3,844,869	3,535,626	301,361	-	5,998	1,884	-
2	876.00	M & R - INDUSTRIAL	17	274,004	-	67,254	-	91,526	115,224	-
3	878.00	METERS & HOUSE REGULATORS	27	2,538,487	1,952,274	559,508	-	20,156	6,194	355
4	879.00	CUSTOMER INSTALLATIONS	15	5,575,022	5,126,623	436,970	-	8,697	2,732	-
5	890.00	M & R - INDUSTRIAL	17	185,003	-	45,409	-	61,797	77,797	-
6	892.00	SERVICES [2]	15	1,613,871	1,484,067	126,495	-	2,518	791	-
7	893.00	METERS & HOUSE REGULATORS	27	244,982	188,408	53,996	-	1,945	598	34
8		TOTAL DISTRIBUTION		14,276,238	12,286,998	1,590,994	-	192,636	205,220	390
9	901.00	SUPERVISION	6	-	-	-	-	-	-	-
10	902.00	METER READING	6	836,787	762,740	72,901	-	921	201	25
11	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSES	6	9,650,214	8,796,267	840,727	-	10,615	2,316	290
12	903.00	INTEREST ON CUSTOMER DEPOSITS	9	89,468	65,556	23,912	-	-	-	-
13	904.00	UNCOLLECTIBLES-DIS REVENUE	7	4,450,409	4,093,887	356,522	-	-	-	-
14	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	8	78,025	1	6,157	-	36,360	32,143	3,364
15	905.00	MISCELLANEOUS	6	36,677	33,432	3,195	-	40	9	1
16	921.00	OFFICE SUPPLIES & EXPENSES	6	-	-	-	-	-	-	-
17		TOTAL CUSTOMER ACCOUNTS		15,141,580	13,751,881	1,303,414	-	47,936	34,669	3,680
18	907.00	SUPERVISION	6	-	-	-	-	-	-	-
19	908.00	CUSTOMER ASSISTANCE	6	576,029	525,074	50,184	-	634	138	-
20	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	73,183	66,707	6,376	-	81	18	2
21	910.00	MISCELLANEOUS	6	1,102,347	1,004,800	96,036	-	1,213	265	33
22	910.00	LARGE CUSTOMER RELATIONS	21	-	-	-	-	-	-	-
23	921.00	OFFICE SUPPLIES & EXPENSES	6	-	-	-	-	-	-	-
24	931.00	RENTS - GENERAL	6	-	-	-	-	-	-	-
25	932.00	MAINTENANCE	6	-	-	-	-	-	-	-
26		TOTAL CUST SERVICE & INFORMATION		1,751,559	1,596,581	152,596	-	1,927	420	35
27	912.00	DEMONSTRATION	6	677,253	617,323	59,002	-	745	163	20
28	913.00	ADVERTISING	6	19,504	17,778	1,699	-	22	5	1
29		TOTAL SALES		696,757	635,101	60,701	-	766	167	21
30		CUSTOMER-RELATED BENEFITS	24	1,536,890	1,084,752	261,071	-	72,249	118,648	169
31		TOTAL CUST-RELATED O&M [LINES 8, 19, 27, 30 & 31]		33,403,023	29,355,313	3,368,777	-	315,514	359,124	4,295
32		DEPRECIATION EXPENSE [PAGE 2, LINE 42]		22,060,729	18,120,443	2,886,465	-	425,713	614,496	13,611
33		INCOME TAXES		13,767,272	12,165,932	1,418,374	-	88,214	86,302	8,450
34		RETURN ON RATE BASE [PAGE 2, LINE 25]		27,981,368	24,726,716	2,882,783	-	179,292	175,404	17,174
35		TOTAL ANNUAL CUSTOMER-BASED COST		97,212,392	84,368,404	10,556,400	-	1,008,732	1,235,326	43,530
36		AVERAGE ANNUAL CUSTOMER BILLS [3]		5,155,145	4,704,314	443,882	0	5,625	1,204	120
37		**MONTHLY CUSTOMER BASED COST/BILL [LINE 36 / LINE 37]**		**$ 18.86**	**$ 17.93**	**$ 23.78**	**$ -**	**$ 179.33**	**$ 1,026.02**	**$ 362.76**

[1] MAINS AND SERVICES @ 26.522% OF TOTAL ACCOUNT 874.
[2] SERVICES @ 99.241% OF ACCOUNT 892.
[3] AVERAGE ANNUAL CUSTOMER BILLS INCLUDE FINAL BILLS.

I&E Exhibit No. 3
Schedule 14

BI&E RECOMMENDED TOTAL CUSTOMER COSTS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RSS/RDS (E) $	SGSS/SCD/SGDS (F) $	N/A (G) $	SDS/LGSS (H) $	LDS/LGSS (I) $	MLDS (J) $
1	874.00	MAINS & SERVICES [SERVICES ONLY][1]	15	3,844,869	3,535,626	301,361	-	5,998	1,884	-
2	876.00	M & R - INDUSTRIAL	17	274,004	-	67,254	-	91,526	115,224	-
3	878.00	METERS & HOUSE REGULATORS	27	2,538,487	1,952,274	559,508	-	20,156	6,194	355
4	879.00	CUSTOMER INSTALLATIONS	15	5,575,022	5,126,623	436,970	-	8,697	2,732	-
5	890.00	M & R - INDUSTRIAL	17	185,003	-	45,409	-	61,797	77,797	-
6	892.00	SERVICES [2]	15	1,613,871	1,484,067	126,495	-	2,518	791	-
7	893.00	METERS & HOUSE REGULATORS	27	244,982	188,408	53,996	-	1,945	598	34
8		TOTAL DISTRIBUTION		14,276,238	12,286,998	1,590,994	-	192,636	205,220	390
9	901.00	SUPERVISION	6	-	-	-	-	-	-	-
10	902.00	METER READING	6	836,787	762,740	72,901	-	921	201	25
11	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSES	6	9,650,214	8,796,267	840,727	-	10,615	2,316	290
12	903.00	INTEREST ON CUSTOMER DEPOSITS	9	89,468	65,556	23,912	-	-	-	-
13	904.00	UNCOLLECTIBLES-DIS REVENUE	7	-	-	-	-	-	-	-
14	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	8	-	-	-	-	-	-	-
15	905.00	MISCELLANEOUS	6	-	-	-	-	-	-	-
16	921.00	OFFICE SUPPLIES & EXPENSES	6	-	-	-	-	-	-	-
17		TOTAL CUSTOMER ACCOUNTS		10,576,469	9,624,562	937,540	-	11,536	2,517	315
18	907.00	SUPERVISION	6	-	-	-	-	-	-	-
19	908.00	CUSTOMER ASSISTANCE	6	-	-	-	-	-	-	-
20	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	-	-	-	-	-	-	-
21	910.00	MISCELLANEOUS	6	-	-	-	-	-	-	-
22	910.00	LARGE CUSTOMER RELATIONS	21	-	-	-	-	-	-	-
23	921.00	OFFICE SUPPLIES & EXPENSES	6	-	-	-	-	-	-	-
24	931.00	RENTS - GENERAL	6	-	-	-	-	-	-	-
25	932.00	MAINTENANCE	6	-	-	-	-	-	-	-
26		TOTAL CUST SERVICE & INFORMATION		-	-	-	-	-	-	-
27	912.00	DEMONSTRATION	6	-	-	-	-	-	-	-
28	913.00	ADVERTISING	6	-	-	-	-	-	-	-
29		TOTAL SALES		-	-	-	-	-	-	-
30	920-931	CUSTOMER-RELATED A&G		2,310,458	1,630,744	392,477	-	108,615	178,367	254
31		CUSTOMER-RELATED BENEFITS	24	1,536,890	1,084,752	261,071	-	72,249	118,648	169
32		TOTAL CUST-RELATED O&M [LINES 8, 19, 27, 30 & 31]		28,700,054	24,627,057	3,182,082	-	385,035	504,752	1,127
33		DEPRECIATION EXPENSE [PAGE 2, LINE 42]		22,060,729	18,120,443	2,886,465	-	425,713	614,496	13,611
34		INCOME TAXES		13,767,272	12,165,932	1,418,374	-	88,214	86,302	8,450
35		RETURN ON RATE BASE [PAGE 2, LINE 25]		27,981,368	24,726,716	2,882,783	-	179,292	175,404	17,174
36		TOTAL ANNUAL CUSTOMER-BASED COST		92,509,423	79,640,147	10,369,706	-	1,078,254	1,380,954	40,362
37		AVERAGE ANNUAL CUSTOMER BILLS [3]		5,155,145	4,704,314	443,882	0	5,625	1,204	120
38		**MONTHLY CUSTOMER BASED COST/BILL [LINE 36 / LINE 37]**		**$ 17.95**	**$ 16.93**	**$ 23.36**	**$ -**	**$ 191.69**	**$ 1,146.97**	**$ 336.35**

[1] MAINS AND SERVICES @ 26.522% OF TOTAL ACCOUNT 874.
[2] SERVICES @ 99.241% OF ACCOUNT 892.
[3] AVERAGE ANNUAL CUSTOMER BILLS INCLUDE FINAL BILLS.

I&E Exhibit No. 3
Schedule 15

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Jeremy B. Hubert, hereby state that the facts set forth in the foregoing document, I&E Statement No. 3, I&E Exhibit No. 3 [Non-Proprietary], and I&E Exhibit No. 3 [Proprietary], are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Jeremy B. Hubert
Jeremy B. Hubert

I&E Statement No. 3-R
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Rebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Cost of Service
Revenue Allocation

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy B. Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. ARE YOU THE SAME JEREMY B. HUBERT WHO SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3 ON JUNE 19, 2015?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to present a response to the direct testimonies submitted by Robert D. Knecht on behalf of the Pennsylvania Office of Small Business Advocate's ("OSBA"), Frank Plank on behalf of the Columbia Industrial Intervenors ("CII"), and James L. Crist, P.E. on behalf of the Pennsylvania State University ("PSU"). I will describe the Bureau of Investigation and Enforcement's ("I&E") positions concerning cost of service methodologies and the impact of the allocated revenue increase on non-flex rate LDS customers.

COST OF SERVICE

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE?

A. As stated in my direct testimony, the Company relied on the results of both the Customer-Demand and the Peak & Average methodologies to provide guidance for the revenue allocation and rate design process (I&E St. No. 3, p. 33).

Q. DID YOU RECOMMEND A CHANGE IN WHAT COST OF SERVICE STUDY SHOULD BE USED AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. Yes. In my direct testimony, I recommended that the Peak and Average methodology be used to allocate the cost of distribution plant and related expenses (I&E St. No. 3, p. 34).

Q. DID OTHER PARTIES SUBMIT DIRECT TESTIMONY CONCERNING COST ALLOCATION STUDIES?

A. Yes. OSBA Witness Knecht provided direct testimony recommending that the Commission rely on a combination of the Company's two cost of service studies, the Peak and Average and Customer/Demand, to determine proposed rates (OSBA St. No.1, p.15). As described in my direct testimony the Customer/Demand method utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KNECHT'S RECOMMENDATION THAT THE COMMISSION RELY ON A COMBINATION OF THE COMPANY'S TWO COST OF SERVICE STUDIES?

A. Yes, as I stated in my direct testimony the Customer/Demand cost of service study should not be relied upon because the Customer/Demand places more of a cost obligation on the customer component of the distribution system, i.e., the system has to reach all customers, which would have a greater impact on the largest class of customers as defined by number of customers, rather than the demand component of the distribution system, i.e., the system has to be sized to meet peak demand, which would have a greater impact on largest class of customers as defined by volume. As systems are built to deliver gas year round and on peak times, and mains cannot be assigned to a single customer, the reliance of the customer component in the Customer-Demand methodology is not in the public interest as it does not match the way in which distributions systems are broadly designed.

Q. SHOULD THE RECOMMENDATION OF MR. KNECHT BE ACCEPTED BY THE COMMISSION?

A. No. As stated in my direct testimony, the Commission generally considers the Peak and Average method as the most useful guide in allocating revenue requirement (I&E St. No. 3, p. 35). The Commission has previously reflected its recognition that distribution mains are built on the basis of year-round demands as well as peak demands. Mr. Knecht did not provide any reasonable rationale to accept a methodology that the Commission has previously rejected.

REVENUE ALLOCATION

Q. DID YOU ADDRESS THE COMPANY'S ORIGINAL REVENUE INCREASE BY CLASS?

A. Yes. I recommended a revenue allocation that adjusted the Company's proposed revenue allocation by re-allocating $3,500,000 from the RSS/RDS rate group to the SGSS/SCD/SGDS and SDS/LGSS rate groups (I&E St. No. 3, p. 42, I&E Ex. No. 3, Sch. 11).

Q. DID ANY OTHER PARTY ADDRESS THE ALLOCATION OF REVENUE TO THE VARIOUS CLASSES BEFORE SCALING BACK RATES?

A. Yes. Both CII witness Plank and PSU witness Crist assert that LDS flex and non-flex should be separated for purposes of evaluating revenue allocation. Mr. Plank recommended that any rate increase to the LDS class be modified to reflect a lower rate increase than that proposed by Columbia to ensure that non-flex customers do not receive an increase that is significantly higher than the system average (CII St. No. 1, p. 8). Mr. Crist's recommendation is of a similar nature, however slightly more explicit, in that his proposal states that only 58% of the increased proposed by Columbia for the LDS class should be allowed, and the remaining 47.2% should be allocated to the non-competitive customers in the other classes, except MLDS/MLSS (PSU St. No. 1, p. 8).

Q. WHAT IS THE BASIS FOR MR. PLANK AND MR. CRIST'S RECOMMENDATION TO REVISE THE COMPANY'S ALLOCATION OF ITS PROPOSED REVENUE INCREASE BY CLASS?

A. Mr. Plank and Mr. Crist indicate that their recommendations are based on the fact that approximately half of the total volumes in the LDS class are flexed and cannot be increased in this proceeding. Therefore, all of the Company's proposed revenue increase for the LDS class is proposed to be recovered from the full tariff LDS customers. Mr. Crist's recommendation consists of re-allocating approximately $1,124,286 (47.2%) of the total $2,381,961 Company proposed increase for the LDS class to the non-flex customers in other classes via the same ratio of revenue allocation proposed by the Company, excluding the MLDS class (PSU St. No. 1, pp. 8-9).

Q. WHY DOES MR. CRIST RECOMMEND THAT THE INCREASE IN REVENUE THAT THE COMPANY HAS ALLOCATED TO THE NON-COMPETITIVE CUSTOMERS OF THE LDS CLASS BE ALLOCATED TO ALL NON-COMPETITIVE CUSTOMERS OF ALL CLASSES?

A. Mr. Crist claims that re-allocating the recovery of 42.7% of the increase in revenue that the Company has allocated to the LDS class is reasonable because all other classes benefit from retaining these flex rate LDS customers through a reduced revenue requirement that gets assigned to all other classes (PSU St. No. 1, pp. 7-8).

Q. WHAT IS MR. PLANK'S RATIONALE FOR HIS ASSERTION THAT LDS FLEX AND NON-FLEX SHOULD BE SEPARATED FOR PURPOSES OF EVALUATING REVENUE ALLOCATION, AND THAT NON-FLEX LDS CUSTOMERS SHOULD NOT RECEIVE AN INCREASE THAT IS SIGNIFICANTLY HIGHER THAN THE SYSTEM AVERAGE?

A. Mr. Plank's rationale is based solely on the size of the percentage increase to non-flex rate LDS customers, resulting from the fact that some rate LDS customers have flexible rate contracts and will not receive any rate increase (CII St. No. 1, pp. 6-8).

Q. DO YOU AGREE WITH THE RECOMMENDATIONS SET FORTH IN THE DIRECT TESTIMONIES OF MR. PLANK AND MR. CRIST THAT THE INCREASE IN REVENUE THAT THE COMPANY HAS ALLOCATED TO THE NON-COMPETITIVE CUSTOMERS OF THE LDS CLASS SHOULD BE ALLOCATED TO ALL NON-COMPETITIVE CUSTOMERS OF ALL CLASSES?

A. No. There are several reasons why Mr. Plank and Mr. Crist's recommendations should be rejected. First, Mr. Plank and Mr. Crist failed to address the results of the cost of service study by arbitrarily recommending that less revenue be collected from tariff rate LDS customers. Second, Mr. Plank and Mr. Crist failed to demonstrate that the revenue received through the proposed LDS tariff rates will recover the costs to serve LDS tariff rate customers. Third, a portion of the revenue shortfall is the result of flexing rates to compete with other Local Distribution Companies ("LDCs"). Fourth, the size of the increase is a function of many things and should not be the primary consideration for allocating revenue. Finally, the argument set forth by Mr. Crist that all other classes benefit from flex rate customers on the system also applies to the existence of every other class on the system. This is not unique to flex customers, and thus does not support his recommendation.

Q. PLEASE ADDRESS THE FIRST REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. Their recommendations should be rejected because it ignores the results of the Company's cost of service study. Under the Company's total requested revenue increase, revenue received from the LDS/LGSS COSS rate group is much less than the cost to provide service to that COSS rate group, justifying a large rate increase for the LDS/LGSS COSS rate group. This is evident by a relative rate of return for the LDS/LGSS COSS rate group of 0.29 under proposed rates (I&E Ex. No. 3, Sch. 11, col. H, ln. 16). The purpose of a cost of service study is to assign costs to rate classes that *cause* the utility to incur those costs, and design class rates to recover those costs. Following this logic, since none of the other classes *caused* any of the LDS class revenue shortfall, the LDS revenue shortfall should not be arbitrarily shifted to other classes.

Q. CAN YOU ELABORATE ON HOW MR. PLANK AND MR. CRIST'S RECOMMENDATION TO ARBITRARILY SHIFT REVENUE VIOLATES THE PURPOSE OF AND RATIONALE FOR A COST OF SERVICE STUDY?

A. Yes. The rate of return generated by each class is determined based off its own costs and recovery. The LDS class includes both flex and non-flex customers, and both groups contribute to the costs of the LDS class as a whole. Mr. Plank and Mr. Crist's recommendations attempt to separate the recovery to be paid by the full tariff LDS customers without separating the cost to serve those LDS customers paying full tariff rates from those LDS customers paying flex rates. I&E is mindful of the increase to non-flexed LDS customers, resulting from the Company's allocation of its proposed revenue increase; however, I do not believe that the LDS flex and non-flex customers should be separated for purposes of evaluating revenue allocation.

Q. PLEASE ADDRESS THE SECOND REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. Their recommendations should be rejected because they have not demonstrated that the proposed rates to be charged to LDS tariff rate customers will recover the cost of providing service to tariff rate customers. Neither Mr. Plank nor Mr. Crist have shown how much of the LDS revenue shortfall is the result of the LDS tariff rates being too low, and how much is the result of the revenue shortfall from LDS discount customers. Therefore, subsequent to applying Mr. Crist's arbitrary increase or $1,257,675 to LDS tariff rate customers, it is impossible to determine if the resulting rates charged to LDS tariff rate customers will recover more or less revenue than the cost of providing service to the LDS tariff rate customers. Therefore, Mr. Plank and Mr. Crist's attempt to separate the revenue to be recovered from full tariff rate LDS customers cannot be accomplished without separating the cost to serve those LDS customers paying full tariff rates from those LDS customers paying flex rates.

Q. PLEASE ADDRESS THE THIRD REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. As described in my direct testimony, Columbia competes with other LDCs for customers. The Commission is currently reviewing if such competition is in the public interest through a generic investigation at Docket No. P-2011-2277868. On June 18, 2014, ALJ Barnes issued a recommended decision stating that:

> The current gas-on-gas competition methodology is discriminatory towards captive customers within the NGDCs' service territories which subsidize annual revenue losses due to discount flex prices offered to large industrial users fortunate enough to have a choice between NGDCs.

As such, some of the flex rate revenue shortfall that Mr. Plank and Mr. Crist propose to allocate to other classes may be reduced if the Commission affirms the decision of ALJ Barnes. Therefore, it would be premature to require other customers in other classes to pay higher rates to make up the LDS class revenue shortfall before the Commission issues an Opinion and Order in that case.

Q. IS THE SIZE OF THE INCREASE A REASON NOT TO APPLY IT?

A. No. The size of the increase is a function of the total requested increase, present rates, and the degree to which the revenue received from a customer class is below the cost to serve that customer class.

Q. PLEASE ADDRESS MR. CRIST'S ARGUMENT THAT ALL OTHER CLASSES BENEFIT FROM HAVING FLEX RATE CUSTOMERS ON THE SYSTEM.

A. Mr. Crist's argument that all other classes benefit from having flex rate customers on the system also applies to the existence of every other class on the system, which is why it doesn't support his recommendation. As described above, the

Commission is left to guess whether or not the revenue received from tariff rate LDS customers is covering the cost to serve tariff rate LDS customers. Furthermore, Mr. Crist's argument is flawed since under this argument, every customer, including each residential customer that pays more than the incremental cost to be served makes a contribution to fixed costs and should also receive a discount, which would increase the revenue requirement for every other customer.

Q. DO YOU ACCEPT THE COMPANY'S PROPOSED REVENUE ALLOCATION TO THE LDS CLASS BEFORE ANY SCALE BACK IS APPLIED?

A. Yes. For the reasons stated above, the cost of the flex rate shortfalls should be borne within the class. Therefore, my recommended revenue allocation of the Company's total requested increase, as shown on I&E Exhibit No. 3, Schedule 11, should be accepted and applied before any scale back.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3-R
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Rebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Cost of Service
Revenue Allocation

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy B. Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. ARE YOU THE SAME JEREMY B. HUBERT WHO SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3 ON JUNE 19, 2015?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to present a response to the direct testimonies submitted by Robert D. Knecht on behalf of the Pennsylvania Office of Small Business Advocate's ("OSBA"), Frank Plank on behalf of the Columbia Industrial Intervenors ("CII"), and James L. Crist, P.E. on behalf of the Pennsylvania State University ("PSU"). I will describe the Bureau of Investigation and Enforcement's ("I&E") positions concerning cost of service methodologies and the impact of the allocated revenue increase on non-flex rate LDS customers.

COST OF SERVICE

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE?

A. As stated in my direct testimony, the Company relied on the results of both the Customer-Demand and the Peak & Average methodologies to provide guidance for the revenue allocation and rate design process (I&E St. No. 3, p. 33).

Q. DID YOU RECOMMEND A CHANGE IN WHAT COST OF SERVICE STUDY SHOULD BE USED AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. Yes. In my direct testimony, I recommended that the Peak and Average methodology be used to allocate the cost of distribution plant and related expenses (I&E St. No. 3, p. 34).

Q. DID OTHER PARTIES SUBMIT DIRECT TESTIMONY CONCERNING COST ALLOCATION STUDIES?

A. Yes. OSBA Witness Knecht provided direct testimony recommending that the Commission rely on a combination of the Company's two cost of service studies, the Peak and Average and Customer/Demand, to determine proposed rates (OSBA St. No.1, p.15). As described in my direct testimony the Customer/Demand method utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KNECHT'S RECOMMENDATION THAT THE COMMISSION RELY ON A COMBINATION OF THE COMPANY'S TWO COST OF SERVICE STUDIES?

A. Yes, as I stated in my direct testimony the Customer/Demand cost of service study should not be relied upon because the Customer/Demand places more of a cost obligation on the customer component of the distribution system, i.e., the system has to reach all customers, which would have a greater impact on the largest class of customers as defined by number of customers, rather than the demand component of the distribution system, i.e., the system has to be sized to meet peak demand, which would have a greater impact on largest class of customers as defined by volume. As systems are built to deliver gas year round and on peak times, and mains cannot be assigned to a single customer, the reliance of the customer component in the Customer-Demand methodology is not in the public interest as it does not match the way in which distributions systems are broadly designed.

Q. SHOULD THE RECOMMENDATION OF MR. KNECHT BE ACCEPTED BY THE COMMISSION?

A. No. As stated in my direct testimony, the Commission generally considers the Peak and Average method as the most useful guide in allocating revenue requirement (I&E St. No. 3, p. 35). The Commission has previously reflected its recognition that distribution mains are built on the basis of year-round demands as well as peak demands. Mr. Knecht did not provide any reasonable rationale to accept a methodology that the Commission has previously rejected.

REVENUE ALLOCATION

Q. DID YOU ADDRESS THE COMPANY'S ORIGINAL REVENUE INCREASE BY CLASS?

A. Yes. I recommended a revenue allocation that adjusted the Company's proposed revenue allocation by re-allocating $3,500,000 from the RSS/RDS rate group to the SGSS/SCD/SGDS and SDS/LGSS rate groups (I&E St. No. 3, p. 42, I&E Ex. No. 3, Sch. 11).

Q. DID ANY OTHER PARTY ADDRESS THE ALLOCATION OF REVENUE TO THE VARIOUS CLASSES BEFORE SCALING BACK RATES?

A. Yes. Both CII witness Plank and PSU witness Crist assert that LDS flex and non-flex should be separated for purposes of evaluating revenue allocation. Mr. Plank recommended that any rate increase to the LDS class be modified to reflect a lower rate increase than that proposed by Columbia to ensure that non-flex customers do not receive an increase that is significantly higher than the system average (CII St. No. 1, p. 8). Mr. Crist's recommendation is of a similar nature, however slightly more explicit, in that his proposal states that only 58% of the increased proposed by Columbia for the LDS class should be allowed, and the remaining 47.2% should be allocated to the non-competitive customers in the other classes, except MLDS/MLSS (PSU St. No. 1, p. 8).

Q. WHAT IS THE BASIS FOR MR. PLANK AND MR. CRIST'S RECOMMENDATION TO REVISE THE COMPANY'S ALLOCATION OF ITS PROPOSED REVENUE INCREASE BY CLASS?

A. Mr. Plank and Mr. Crist indicate that their recommendations are based on the fact that approximately half of the total volumes in the LDS class are flexed and cannot be increased in this proceeding. Therefore, all of the Company's proposed revenue increase for the LDS class is proposed to be recovered from the full tariff LDS customers. Mr. Crist's recommendation consists of re-allocating approximately $1,124,286 (47.2%) of the total $2,381,961 Company proposed increase for the LDS class to the non-flex customers in other classes via the same ratio of revenue allocation proposed by the Company, excluding the MLDS class (PSU St. No. 1, pp. 8-9).

Q. WHY DOES MR. CRIST RECOMMEND THAT THE INCREASE IN REVENUE THAT THE COMPANY HAS ALLOCATED TO THE NON-COMPETITIVE CUSTOMERS OF THE LDS CLASS BE ALLOCATED TO ALL NON-COMPETITIVE CUSTOMERS OF ALL CLASSES?

A. Mr. Crist claims that re-allocating the recovery of 42.7% of the increase in revenue that the Company has allocated to the LDS class is reasonable because all other classes benefit from retaining these flex rate LDS customers through a reduced revenue requirement that gets assigned to all other classes (PSU St. No. 1, pp. 7-8).

Q. WHAT IS MR. PLANK'S RATIONALE FOR HIS ASSERTION THAT LDS FLEX AND NON-FLEX SHOULD BE SEPARATED FOR PURPOSES OF EVALUATING REVENUE ALLOCATION, AND THAT NON-FLEX LDS CUSTOMERS SHOULD NOT RECEIVE AN INCREASE THAT IS SIGNIFICANTLY HIGHER THAN THE SYSTEM AVERAGE?

A. Mr. Plank's rationale is based solely on the size of the percentage increase to non-flex rate LDS customers, resulting from the fact that some rate LDS customers have flexible rate contracts and will not receive any rate increase (CII St. No. 1, pp. 6-8).

Q. DO YOU AGREE WITH THE RECOMMENDATIONS SET FORTH IN THE DIRECT TESTIMONIES OF MR. PLANK AND MR. CRIST THAT THE INCREASE IN REVENUE THAT THE COMPANY HAS ALLOCATED TO THE NON-COMPETITIVE CUSTOMERS OF THE LDS CLASS SHOULD BE ALLOCATED TO ALL NON-COMPETITIVE CUSTOMERS OF ALL CLASSES?

A. No. There are several reasons why Mr. Plank and Mr. Crist's recommendations should be rejected. First, Mr. Plank and Mr. Crist failed to address the results of the cost of service study by arbitrarily recommending that less revenue be collected from tariff rate LDS customers. Second, Mr. Plank and Mr. Crist failed to demonstrate that the revenue received through the proposed LDS tariff rates will recover the costs to serve LDS tariff rate customers. Third, a portion of the revenue shortfall is the result of flexing rates to compete with other Local Distribution Companies ("LDCs"). Fourth, the size of the increase is a function of many things and should not be the primary consideration for allocating revenue. Finally, the argument set forth by Mr. Crist that all other classes benefit from flex rate customers on the system also applies to the existence of every other class on the system. This is not unique to flex customers, and thus does not support his recommendation.

Q. PLEASE ADDRESS THE FIRST REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. Their recommendations should be rejected because it ignores the results of the Company's cost of service study. Under the Company's total requested revenue increase, revenue received from the LDS/LGSS COSS rate group is much less than the cost to provide service to that COSS rate group, justifying a large rate increase for the LDS/LGSS COSS rate group. This is evident by a relative rate of return for the LDS/LGSS COSS rate group of 0.29 under proposed rates (I&E Ex. No. 3, Sch. 11, col. H, ln. 16). The purpose of a cost of service study is to assign costs to rate classes that *cause* the utility to incur those costs, and design class rates to recover those costs. Following this logic, since none of the other classes *caused* any of the LDS class revenue shortfall, the LDS revenue shortfall should not be arbitrarily shifted to other classes.

Q. CAN YOU ELABORATE ON HOW MR. PLANK AND MR. CRIST'S RECOMMENDATION TO ARBITRARILY SHIFT REVENUE VIOLATES THE PURPOSE OF AND RATIONALE FOR A COST OF SERVICE STUDY?

A. Yes. The rate of return generated by each class is determined based off its own costs and recovery. The LDS class includes both flex and non-flex customers, and both groups contribute to the costs of the LDS class as a whole. Mr. Plank and Mr. Crist's recommendations attempt to separate the recovery to be paid by the full tariff LDS customers without separating the cost to serve those LDS customers paying full tariff rates from those LDS customers paying flex rates. I&E is mindful of the increase to non-flexed LDS customers, resulting from the Company's allocation of its proposed revenue increase; however, I do not believe that the LDS flex and non-flex customers should be separated for purposes of evaluating revenue allocation.

Q. PLEASE ADDRESS THE SECOND REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. Their recommendations should be rejected because they have not demonstrated that the proposed rates to be charged to LDS tariff rate customers will recover the cost of providing service to tariff rate customers. Neither Mr. Plank nor Mr. Crist have shown how much of the LDS revenue shortfall is the result of the LDS tariff rates being too low, and how much is the result of the revenue shortfall from LDS discount customers. Therefore, subsequent to applying Mr. Crist's arbitrary increase or $1,257,675 to LDS tariff rate customers, it is impossible to determine if the resulting rates charged to LDS tariff rate customers will recover more or less revenue than the cost of providing service to the LDS tariff rate customers. Therefore, Mr. Plank and Mr. Crist's attempt to separate the revenue to be recovered from full tariff rate LDS customers cannot be accomplished without separating the cost to serve those LDS customers paying full tariff rates from those LDS customers paying flex rates.

Q. PLEASE ADDRESS THE THIRD REASON WHY MR. PLANK AND MR. CRIST'S RECOMMENDATIONS SHOULD BE REJECTED.

A. As described in my direct testimony, Columbia competes with other LDCs for customers. The Commission is currently reviewing if such competition is in the public interest through a generic investigation at Docket No. P-2011-2277868. On June 18, 2014, ALJ Barnes issued a recommended decision stating that:

> The current gas-on-gas competition methodology is discriminatory towards captive customers within the NGDCs' service territories which subsidize annual revenue losses due to discount flex prices offered to large industrial users fortunate enough to have a choice between NGDCs.

As such, some of the flex rate revenue shortfall that Mr. Plank and Mr. Crist propose to allocate to other classes may be reduced if the Commission affirms the decision of ALJ Barnes. Therefore, it would be premature to require other customers in other classes to pay higher rates to make up the LDS class revenue shortfall before the Commission issues an Opinion and Order in that case.

Q. IS THE SIZE OF THE INCREASE A REASON NOT TO APPLY IT?

A. No. The size of the increase is a function of the total requested increase, present rates, and the degree to which the revenue received from a customer class is below the cost to serve that customer class.

Q. PLEASE ADDRESS MR. CRIST'S ARGUMENT THAT ALL OTHER CLASSES BENEFIT FROM HAVING FLEX RATE CUSTOMERS ON THE SYSTEM.

A. Mr. Crist's argument that all other classes benefit from having flex rate customers on the system also applies to the existence of every other class on the system, which is why it doesn't support his recommendation. As described above, the

Commission is left to guess whether or not the revenue received from tariff rate LDS customers is covering the cost to serve tariff rate LDS customers. Furthermore, Mr. Crist's argument is flawed since under this argument, every customer, including each residential customer that pays more than the incremental cost to be served makes a contribution to fixed costs and should also receive a discount, which would increase the revenue requirement for every other customer.

Q. DO YOU ACCEPT THE COMPANY'S PROPOSED REVENUE ALLOCATION TO THE LDS CLASS BEFORE ANY SCALE BACK IS APPLIED?

A. Yes. For the reasons stated above, the cost of the flex rate shortfalls should be borne within the class. Therefore, my recommended revenue allocation of the Company's total requested increase, as shown on I&E Exhibit No. 3, Schedule 11, should be accepted and applied before any scale back.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Jeremy B. Hubert, hereby state that the facts set forth in the foregoing document, I&E Statement No. 3-R, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Jeremy B. Hubert
Jeremy B. Hubert

I&E Statement No. 3-SR
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Surrebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Rate Base
Present Rate Revenues
Cost of Service
Scaleback
Customer Cost Analysis
Customer Charges
CAC Rider

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy B. Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. ARE YOU THE SAME JEREMY B. HUBERT WHO SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3 ON JUNE 19, 2015 AND I&E STATEMENT NO. 3-R ON JULY 16, 2015?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to present a response to the rebuttal testimonies submitted by Amy L. Efland, Brian E. Elliott, Mark Balmert, and Nancy J.D. Krajovic on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"), Robert D. Knecht on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"), and James L. Crist, P.E on behalf of The Pennsylvania State University ("PSU"). I will describe the Bureau of Investigation and Enforcement's ("I&E") positions concerning the effect of projected use per customer on present rate revenues, customer cost analysis, customer charges, the use of the most representative cost of service study, manner of scale back, and the creation of the Choice Administration Charge Rider ("Rider CAC").

RATE BASE

Q. WHAT IS THE COMPANY'S AS FILED TOTAL RATE BASE CLAIM FOR THE FPFTY ENDING DECEMBER 31, 2016?

A. Columbia's as filed claimed rate base for the FPFTY ending December 31, 2016 is $1,325,130,928 (Columbia Ex. No. 108, p. 3 of 11).

Q. HAS THE COMPANY MADE ANY REVISIONS TO ITS FPFTY RATE BASE CLAIM IN REBUTTAL TESTIMONY?

A. Yes. As described by Mr. Spanos in Columbia Statement No. 105-R, page 5, the Company's reserve for depreciation and amortization was overstated by $126,310 for the FPFTY. The reserve should be $386,611,458 for the FPFTY, as opposed to $386,737,768 presented in Columbia Exhibit No. 108, Column 5, line, 5. This revision increases the Company's rate base by $126,310 to $1,325,257,238.

Q. DO YOU ACCEPT THE COMPANY'S REVISED RATE BASE CLAIM FOR THE FPFTY, AS PRESENTED BY MR. SPANOS?

A. Yes. Additionally, as stated in my direct testimony, I recommend that the Company continue to provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2016, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending December 31, 2015. An additional update should be provided for actuals through December 31, 2016, no later than April 1, 2017.

REVENUE USAGE PER CUSTOMER

Q. WHAT DID THE COMPANY CLAIM CONCERNING DECLINING RESIDENTIAL USAGE?

A. The Company claims that residential usage is declining as a result of limited end uses for natural gas, accelerated appliance replacements, high efficiency appliance installations, modifications to new and existing buildings which are designed to decrease energy consumption, changes in consumer usage behavior in response to energy price changes, and other economic influences (Columbia St. No. 2, pp. 15-16). Therefore, based on the Company's analysis of usage over the past twenty-two years, the Company projected that the average use per residential customer will be 87.44 Dth per year on a composite basis for the FPFTY (I&E St. No. 3. p. 23).

Q. DID YOU ADDRESS THE COMPANY'S CLAIMED DECLINE IN RESIDENTIAL USAGE?

A. Yes. I determined that residential usage is not declining in such a manner as the Company projects. I calculated the average of five changes in consumption experienced by the Company in usage by Residential customers over the most recent six-year period (2009-TME November 2014) to be an increase of 0.56 Dth per year (I&E Ex. No. 3, Sch. 7, col. C, ln. 13). Therefore, I recommended that the average use per residential customer should be 92.92 Dth per year on a composite basis for the FPFTY (I&E St. No. 3. p. 24).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION TO INCREASE THE AVERAGE USAGE PER RESIDENTIAL CUSTOMER TO 92.92 DTH ON A COMPOSITE BASIS?

A. Yes. The Company disagrees with my recommendation. Company witness Efland continues to claim that 20 years' worth of data should be used to determine the decline in usage, based on non-weather factors, and believes I used a time period that is too limited, creating instability in my estimation method(Columbia St. No. 102-R, pp. 2-6).

Q. PLEASE ADDRESS THE COMPANY'S CLAIM THAT THE TIME PERIOD YOU USED TO DETERMINE AVERAGE USAGE IS IMPROPER.

A. First, the historic time period selected to determine projected usage is a matter of judgment. This is evident by the Company's failure to cite any authority that 20 years of data must be used. Therefore, in the exercise of informed judgment the selection of any one time period is not improper so long as that judgment is justified. In rebuttal testimony, Company witness Efland asserts that customer usage patterns as far back 1991 should be used to project average usage in 2015-

2016, or 24 years later. As stated in my direct testimony, I believe data from that far back is stale and not representative of current usage trends. Therefore, I do not believe my selection of the time period to project average usage per customer in 2016 is improper.

Q. IS THE COMPANY CORRECT THAT IT IS REASONABLE TO CONCLUDE THAT USAGE WILL CONTINUE TO DECLINE UNINTERRUPTED EACH YEAR AS SHOWN BY COMPANY'S TRENDING ANALYSIS?

A. No. If it were a reasonable conclusion, it would have been correct in the past. However, this conclusion would have been incorrect in 2006 to project usage for 2007, incorrect in 2009 to project usage for 2010, and incorrect in 2012 to project usage for 2013. In these intervals residential usage per customer increased not decreased. Additionally, as highlighted in my direct testimony, Ms. Efland's claim in the Company's previous base rate proceeding at Docket No. R-2014-2406274 that Residential usage will continue to decline and her subsequent projected decline in Residential usage per customer for the twelve months ending November 30, 2014 were both incorrect (I&E St. No. 3, pp. 21-22). Also, since no one can accurately predict the future, the guarantee by the Company that sales will decline in the future is speculative and should not be accepted.

Q. DID THE COMPANY PROVIDE MORE RECENT USAGE DATA?

A. Yes. Ms. Efland provided more recent residential usage data, shown on page 4 of Columbia Statement No. 102-R.

Q. AS A RESULT OF THE INCLUSION OF MORE RECENT USAGE DATA DO YOU WISH TO REVISE YOUR PROJECTED USAGE PER RESIDENTIAL CUSTOMER FOR THE FPFTY?

A. Yes. Based upon a revised calculation, utilizing Ms. Efland's residential usage data, shown on page 4 of Columbia Statement No. 102-R, I have now determined that residential usage per customer should be 89.42 Dth per year on a composite basis for the FPFTY.

Q. HOW DID YOU DETERMINE THE RESIDENTIAL USAGE PER CUSTOMER OF 89.42 DTH PER YEAR?

A. The 89.42 Dth per year is based on the weighted average normalized usage for the twelve month periods ending December 2010, December 2011, December 2012, December 2013, November 2014, and April 2015. In other words, the 89.42 Dth per year is the weighted average of normalized usage for each of the years 2010, 2011, 2012, 2013, the eleven month period ending November 2014, and the five month period ending April 2015, as shown on Table 1R on page 4 of Columbia Statement No. 102-R, rather than the average of the five changes in consumption experienced between the years 2009-10, 2010-11, 2011-12, 2012-13, and 2013-14. The differences in the calculations are summarized below:

Year	Usage Per Residential Customer (Dth/year)	Average Monthly Residential Usage Per Customer (Dth/month)	Number of Months		Change in Usage Per Customer (Dth) (Ref. I&E Ex. No. 3, Sch. 7)
TME December 2009	89.00				
					0.50
TME December 2010	89.50	7.46	12	18.8%	
					-0.50
TME December 2011	89.00	7.42	12	18.8%	
					-2.20
TME December 2012	86.80	7.23	12	18.8%	
					3.30
TME December 2013	90.10	7.51	12	18.8%	
					1.70
TME November 2014	91.80	7.65	11	17.2%	
TME April 2015	89.60	7.47	5	7.8%	
Weighted Average	**89.42**	**7.45**	64	100.0%	**0.56**
					Average change over 6 years (2009 - TME Nov. 2014)

Q. WHY DID YOU UTILIZE A SIMPLE WEIGHTED AVERAGE OF THE MOST RECENT SIX TIME PERIODS RATHER THAN THE METHODOLOGY YOU USED IN DIRECT TESTIMONY?

A. The Company's usage has not declined consistently. Rather, the numbers go both up and down. For that reason, I do not believe the decline in usage will necessarily continue uninterrupted each year as the Company's trending analysis concludes, but rather that usage may increase or decrease as it has over the past five years, even if the results of the trend are lower usage from a given starting point.

As shown above, between 2009 and 2011, average usage per residential customer remained about the same at approximately 89 Dth per customer. There was a fairly large decrease in 2012 and a fairly large increase in 2013, which appear to be anomalies. I believe that my recommendation of 89.42 Dth based upon a simple weighted average of the consumption over the past six time periods more reasonably estimates a more levelized amount that occurred within the last five years and is likely to be representative going forward.

Q. WHY IS IT IMPORTANT TO REFLECT A REPRESENTATIVE ESTIMATE OF USAGE IN THE FTY AND FPFTY IN THIS PROCEEDING?

A. If rates are designed based upon the Company's projected declining usage as presented in this case, the Company's rates will be higher than they need to be to earn the authorized revenue increase. Consequently, the Company likely will earn more revenues than authorized.

Q. WHAT IS THE IMPACT ON RESIDENTIAL REVENUE IF PROJECTED RESIDENTIAL USE PER CUSTOMER IS INCREASED TO 89.42 DTH PER YEAR?

A. Increasing the average residential usage per customer on a composite basis from 87.44 Dth per year to 89.42 Dth per year results in $7,485,551 in additional present rate revenue in the FPFTY (I&E Ex. No. 3-SR. Sch. 1, col. C, ln. 15).

Q. WHAT USAGE DID YOU ADJUST SO THAT THE TOTAL USAGE PER RESIDENTIAL CUSTOMER EQUALS 89.42 DTH PER YEAR?

A. Similar to my analysis described in my direct testimony, I increased the average use per residential RSS customer to 86.57 Dth per year so that the average composite usage for all residential customers is 89.42 Dth per year (I&E Ex. No. 3-SR, Sch. 2, col. H, ln. 2). As shown on I&E Exhibit No. 3-SR, Schedule 2, line 2, if residential RSS customer usage is increased by approximately 768,537 Dth (24,049,213 Dth – 23,280,676 Dth), the average use per RSS customer increases by 2.77 Dth per year to 86.57 Dth per year.

Q. IF THE COMMISSION ACCEPTS THE $7,485,551 INCREASE IN PRESENT REVENUES FOR THE RESIDENTIAL CLASS, SHOULD THERE ALSO BE A CORRESPONDING INCREASE IN THE COST OF GAS EXPENSE?

A. Yes. If the Commission accepts my recommend $7,485,551 increase in present rate revenues for the residential class, there should be a corresponding increase of $4,141,723 in the cost of gas expense for the additional gas, as shown on I&E Exhibit No. 3-SR, Schedule 1, column C, line 16.

CUSTOMER COST ANALYSIS

Q. DID YOU CONDUCT A CUSTOMER COST ANALYSIS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I conducted a customer cost analysis and attached the analysis as I&E Exhibit No. 3, Schedule 15.

Q. WAS YOUR CUSTOMER COST ANALYSIS BASED ON ONE OF THE CUSTOMER COST ANALYSES PROVIDED BY THE COMPANY?

A. Yes. The customer cost analysis that I prepared was based on the Company's customer cost analysis utilizing the Peak and Average cost of service methodology that excludes the customer component of mains. I included the results of the Company's customer cost analysis as I&E Exhibit No. 3, Schedule 14. The Company's customer cost analysis utilizing the Peak and Average cost of service methodology was provided as part of Attachment B to discovery request I&E-RS-27-D.

Q. WHAT ITEMS DID YOU EXCLUDE AND WHERE ARE THE RESULTS OF YOU CUSTOMER COST ANALYSIS SHOWN?

A. The difference between my analysis and the Company's analysis is that I excluded miscellaneous customer accounts expense and uncollectibles revenue, customer assistance expense, informational and instructional expense, miscellaneous customer service and information expenses, demonstration and advertising expenses, and all claimed administrative and general expenses with the exception of employee pension and benefits (I&E St. No. 3, pp. 47-48). The results of my customer cost analysis are shown on I&E Exhibit No. 3, Schedule 15, which accompanied my direct testimony.

Q. DID THE COMPANY ADDRESS YOUR CUSTOMER COST ANALYSIS?

A. Yes. Mr. Balmert claims that I have improperly excluded several indirect costs in my customer cost analysis basis. Mr. Balmert believes that allocating cost in the system wide cost of service study justifies inclusion of the same types of costs in the customer cost analysis. Therefore, Mr. Balmert claims that since I have recognized several expenses to be customer-related for the determination of class revenue responsibility by using the Peak & Average study as a basis, those same customer based fixed costs should also be included in determination of customer charge recovery (Columbia St. No. 111-R, pp. 19-20). In other words, Mr. Balmert believes that if costs are allocated to the customer function, or by the number of customers in the cost of service study, those costs should automatically be included in the customer cost analysis and recovered in the customer charge.

Q. IS IT CORRECT TO UTILIZE THE FUNCTIONALIZATION OF COST IN A COST OF SERVICE STUDY TO JUSTIFY INCLUDING THOSE COSTS IN THE CUSTOMER COST ANALYSIS?

A. No. They are two separate analyses. While the customer cost analysis is generally based on the cost of service study, a customer cost analysis is more focused and done to determine the proper direct (and limited indirect) costs that should be recovered in the customer charge within a specific customer class (Aqua Pennsylvania case at Docket No. R-00038805, Order entered August 4, 2004).

<u>CUSTOMER CHARGES – RESIDENTIAL</u>

Q. DID YOU RECOMMEND CHANGES TO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES

A. Yes. I recommended that the present residential customer charge of $16.75 per month be increased to $16.93 per month, as opposed to the Company's proposed residential customer charge of $20.60 per month (I&E St. No. 3, p. 50).

Q. WHAT WAS YOUR BASIS FOR RECOMMENDING THAT THE $16.75 PER MONTH RESIDENTIAL CUSTOMER CHARGE BE INCREASED TO $16.93 PER MONTH?

A. This customer charge recommendation is based on my customer cost analysis provided in direct testimony (I&E St. No. 3, pp. 50-51).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION?

A. Yes. It appears that the Company believes that its $20.60 per month proposed customer charge for residential customers is reasonable and is fully supported by Mr. Elliott's customer cost analysis. However, Mr. Balmert did note that had I included those customer based fixed costs, which he believes were improperly excluded from my customer cost analysis, the residential customer charge would be $17.41 per month instead of my calculated $16.93 per month (Columbia St. No. 111-R, p. 20).

Q. DO YOU AGREE WITH THE COMPANY THAT THE PROPOSED MONTHLY RESIDENTIAL CUSTOMER CHARGE IS REASONABLE?

A. No. There is no cost basis for increasing the present monthly residential customer charges to the level requested by the Company. As shown in my customer cost analysis, the Company incurs $16.93 per month in direct and indirect costs to serve the residential class (I&E Ex. No. 3, Sch. 15). Even with the inclusion of Mr. Balmert's claimed additional costs the Company would only incur $17.41 per month in costs to serve the residential class as opposed to its proposed $20.60 per month residential customer charge (Ex. MPB-2R). Therefore, I continue to recommend a residential customer charge of $16.93 per month.

CUSTOMER CHARGES – SGSS/SCD/SGDS

Q. WHAT CUSTOMER CHARGES DID YOU RECOMMEND FOR THE SGSS, SCD AND SGDS CLASSES IN DIRECT TESTIMONY?

A. I recommended that the present $21.25 per month customer charge for SGSS, SCD, and SGDS class customers using less than 6,440 therms annually should not be increased by more than $2.11 per month ($23.36 - $21.25) (I&E St. No. 3, p. 52). For those SGSS, SCD, and SGDS class customers using between 6,440 and 64,400 therms annually I recommended that the present $48.00 per month customer charge should remain at its current level (I&E St. No. 3, p. 52).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION?

A. Yes. It appears that the Company believes that its proposed customer charges for SGSS, SCD and SGDS classes are still reasonable and are supported by Mr. Elliott's customer cost analysis. However, Mr. Balmert did note that had I included those customer based fixed costs, which he believes were improperly excluded from my customer cost analysis, the SGSS/SCD/SGDS customer charge would be $23.85 per month instead of my calculated $23.36 per month for customers who use less than 6,440 therms annually (Columbia St. No. 111-R, p. 37).

Q. DO YOU AGREE WITH THE COMPANY THAT THE PROPOSED MONTHLY CUSTOMER CHARGES FOR SGSS, SCD, AND SGDS CLASS CUSTOMERS ARE REASONABLE?

A. No. There is no cost basis for increasing the present SGSS/SCD/SGDS customer charges to the level requested by the Company. As shown in my customer cost analysis, the Company incurs $23.36 per month in direct and indirect SGSS/SCD/SGDS class customer costs to provide service (I&E Ex. No. 3, Sch. 15). Even with the inclusion of Mr. Balmert's claimed additional costs the Company would only incur $23.85 per month in costs to serve the SGSS/SCD/SGDS classes as opposed to its proposed $27.75 per month for SGSS, SCD, and SGDS customers using less than 6,440 therms annually (Exhibit MPB-2R). Therefore, I continue to recommend that the present $21.25 per month customer charge for SGSS, SCD, and SGDS class customers using less than 6,440 therms annually should not be increased by more than $2.11 per month ($23.36 - $21.25). Additionally, I continue to recommend that the present $48.00 per month customer charge for SGSS, SCD, and SGDS class customers using between 6,440 and 64,400 therms annually remain at its current level. Keeping the customer charge for these customers at this level exceeds the $23.36 per month in customer costs the Company incurs to serve each SGSS, SCD, and SGDS class customer, as shown on I&E Exhibit No. 3, Schedule 15, as well as, the $23.85 per month in costs to serve these customers, which assumes the inclusion of Mr. Balmert's claimed additional costs (Ex. No. MPB-2R).

COST OF SERVICE

Q. EXPLAIN HOW A COST OF SERVICE STUDY IS USED IN THE RATEMAKING PROCESS.

A. A cost of service study provides analytical support for proposed revenue allocation and rate changes. The majority of a natural gas distribution company's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. The majority of Columbia's plant and expenses are incurred jointly to serve all (or most) customers. These joint costs should then be allocated to rate classes based on the concept of cost causation. When performing a fully allocated cost of service study, every cost, which comprises the total costs of providing service, must be either directly assigned or allocated to the customer classes. Once the cost of service analysis is complete, the results are applied in rate design.

Q. WITH REGARD NATURAL GAS DISTRIBUTION COMPANY'S SPECIFICALLY, ARE THERE A COMMON SET OF EXTERNAL FACTORS, OR DRIVERS, USED IN VIRTUALLY EVERY COST OF SERVICE STUDY?

A. Yes. Practically every utility cost allocation study rests on the analysts' selection of three primary external allocation factors: 1) number of customers, 2) peak demand, and 3) annual (average day) usage. From these three factors internally generated allocation factors are developed based on previously allocated plant and expenses.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. As indicated in my direct testimony, the Peak and Average approach is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class' utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE IN DIRECT TESTIMONY?

A. As stated in my direct testimony, Company witness Balmert relied upon the Average study, which has an equal weighting of the Customer-Demand and Peak & Average ("P&A") studies, when designing the proposed revenue requirement and rates (I&E St. No. 3, p. 33).

Q. HOW DO THE CUSTOMER-DEMAND AND THE P&A PREPARED BY COLUMBIA DIFFER?

A. The two cost of service studies prepared by Columbia differ in that each study utilizes a different approach to the allocation of distribution mains investment. In the Customer-Demand study, distribution mains investment is allocated based partially on the design day demands of each of the customer classes served by Columbia, and partially on the number of customers in each class. In the P&A study, distribution mains investment is allocated 50% based on the design day demands of each customer class and 50% based on annual, or average daily, demands.

Q. DO YOU RECOMMEND THAT ONLY ONE COST OF SERVICE STUDY BE USED AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. Yes. In direct testimony, I recommended that the Peak & Average methodology be used to allocate the cost of distribution plant and related expenses (I&E St. No. 3, p. 34).

Q. WHAT WAS THE RESPONSE FROM THE COMPANY AND OTHER PARTIES TO YOUR RECOMMENDATION?

A. The Company disagrees specifically with my recommendation pertaining to the allocation of the cost of mains to the various classes based on the P&A method and continues to assert that a mix of cost of service studies should be used (Columbia St. No. 107-R, pp. 5-23). OSBA witness Knecht suggests that my reliance on Commission precedent, does not support the use of the Company's proposed P&A cost of service study methodology in this proceeding, and recommends reliance on a combination of both Company cost of service methodologies, with a 75 percent weighting to the P&A study and 25 percent weighting to the Customer-Demand study (OSBA St. No. 2, p. 5). PSU witness Crist also disagrees with my recommendation to allocate the cost of mains to the various customer classes based on the P&A method and supports the Company's methodology with the belief that revenue and rates should be established based on a proper allocation of distribution mains which relies upon both the peak demand and the number of customers (PSU St. No. 1-R, pp. 3-4).

Q. WHAT RATIONALE DID THE COMPANY PROVIDE FOR NOT AGREEING WITH YOUR RECOMMENDATION?

A. The Company does not concur that a single cost study should form the basis of a rate design (Columbia St. No. 107-R, p. 23). Mr. Elliott states that it is combination of the cost to extend a distribution main (customer component) and the cost of the diameter of the pipe to serve customers at design day temperatures (demand component) that determines the causation of the cost of the main, and not the service received by its customers during all other times of the year (throughput) (Columbia St. No. 107-R, p. 7). Therefore, because 50% of the Peak & Average study is based on throughput, it does not reflect the manner in which the Company actually incurs costs to provide service. Mr. Elliott believes that to simply choose an allocation method that either fully ignores annual throughput or completely ignores the customer component should not be seriously considered as fair and reasonable (Columbia St. No. 107-R, p. 23).

Q. IS THE COMPANY'S STATED BELIEF A PROPER BASIS FOR ALLOCATING THE COST OF MAINS TO THE VARIOUS CUSTOMER CLASSES?

A. No. During the Company's previous base rate proceeding at Docket No. R-2014-2406274, Mr. Elliott has recognized that the Commission generally considers cost of service studies that rely more heavily on annual or average throughput (Peak & Average and Average and Excess) as the most useful guide in allocating revenue requirement (Columbia St. No. 111-R, p. 24, Docket No. R-2014-2406274). There is simply no demonstrated reason here to consider allocating a percentage of the cost of distribution mains based on the number of customers, a methodology that the Commission has previously rejected. In the Philadelphia Gas Works base rate proceeding at Docket No. R-00061931, the Commission found that mains allocations based on the number of customers are not acceptable (Order entered September 28, 2007).

Q. WHAT RATIONALE DID PSU WITNESS CRIST PROVIDE FOR HIS SUPPORT OF THE COMPANY'S COST OF SERVICE STUDY METHODOLOGY?

A. Mr. Crist believes that the use of a commodity-based allocation factor, such as the P&A method violates the fundamental principle of cost causation because throughput is not what causes Columbia's investment in the fixed costs of distribution mains and the treatment of mains using the P&A demand allocation method results in a misallocation of cost to the Company's classes of service. Furthermore, the Mr. Crist believes that recognition of a customer component of distribution mains is an appropriate cost classification and allocation method and to ignore the customer component of distribution mains would be to ignore a key factor affecting the cost of distribution mains – the number of customers served by the utility (PSU St. No. 1-R, pp. 2-4).

Q. IS MR. CRIST'S BELIEF A PROPER BASIS FOR ALLOCATING THE COST OF MAINS TO THE VARIOUS CUSTOMER CLASSES?

A. No. As stated previously, the Company has recognized in prior proceedings that the Commission generally considers a cost of service method which treats the costs of distribution mains without recognizing a customer component as the most useful guide in allocating revenue requirement. PSU witness Crist advocates the allocation of mains based partly on the number of customers and contributions to design day demand. However, as stated in my direct testimony, Commission has previously recognized that distribution mains are built on the basis of both year-round as well as peak demands (I&E St. No. 3, p. 35). There is simply no demonstrated reason here to consider a methodology that the Commission has previously rejected.

Q. WHAT IS YOUR RESPONSE TO MR. CRIST'S ASSERTION THAT COSTS FOR MAIN SHOULD BE ALLOCATED IN PART ON CUSTOMER COUNT BECAUSE MAINS ARE PUT IN SERVICE TO SERVE CUSTOMERS?

A. As stated in my direct testimony, although mains serve customers, it is the throughput that determines the type of main investment. Because it is the load that determines the main investment, not the number of customers served, the P&A allocation methodology is the most appropriate allocation methodology because it is based on this premise of load based investment. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served. Imagine two separate streets: Street A has only one commercial customer that exhibits a maximum demand of 10 Dth and Street B has 10 residential customers, each with a peak demand of 1 Dth. The distribution main serving the 10 residential customers on Street B would have to be sized to deliver 10 Dth at peak. The distribution main on Street A would also have to be sized to deliver 10 Dth at peak to serve the 1 commercial customer. So while mains serve customers, the number of customers does not determine the main investment (I&E St. No. 3, p. 32).

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KNECHT'S RECOMMENDATION THAT THE COMMISSION RELY ON A COMBINATION OF THE COMPANY'S TWO COST OF SERVICES STUDIES?

A. Yes. I disagree with Mr. Knecht for the reasons reviewed in my rebuttal testimony when disagreeing with his recommendation in addition to the reason's stated above when objecting with both Mr. Elliott and Mr. Crist's use of the Company's Customer-Demand cost allocation method (I&E St. No. 3-R, pp. 2-4). Similar to my position regarding Mr. Elliott and Mr. Crist's recommendations, I disagree with the reliance on a combination of the cost of service studies because it is recognized that distribution mains are built on the basis of both year round and peak demands, and although mains service customers, throughput determines main investment.

Q. OSBA WITNESS KNECHT INDICATES THAT THE COMMISSION HAS APPROVED USE OF THE AVERAGE-AND-EXCESSS ("A&E") METHOD IN A PRIOR PHILADELPHIA GAS WORKS ("PGW") PROCEEDING. DO YOU HAVE ANY COMMENTS?

A. Yes. Similar to my previous noting of Company witness Elliott's recognition of the Commission's past reliance on cost of service studies that rely more heavily on annual or average throughput, Mr. Knecht also acknowledges that in approving the A&E approach, the Commission has expressly rejected the use of a customer component for mains cost allocation (OSBA St. No. 2, p. 5). In the referenced proceeding, the Commission has previously found that the mains allocations based on the number of customers are not acceptable (PGW Docket No. R-0061931, Order at 80). Concerning the present proceeding, I find that either the P&A or the A&E method is acceptable; however, a cost of service study utilizing the A&E methodology has not been provided by the Company in this proceeding.

Q. DOES MR. KNECHT POINT OUT ANY OTHER RECENT COMMISSION PRECEDENT WHICH HE CLAIMS INTRODUCES AMBIGUITY AS TO WHETHER OR NOT COST ALLOCATION FOR UTILITY DISTRIBUTION SYSTEMS SHOULD OR SHOULD NOT INCLUDE A CUSTOMER COMPONENT OF COSTS?

A. Yes. Mr. Knecht pointed out that recent Commission precedent for electric distribution utilities supports the recognition of a customer component for distribution plant (OSBA St. No. 2, p. 5). Mr. Knecht refers to a recent PPL Electric Utilities Corporation rate case. However, there are often distinct differences between electric distribution companies and natural gas distribution companies. These differences include the fact that electric distribution cost of service studies use customer and demand allocators, while gas and water companies also use volumes as an allocator; additionally, there are differences as it relates to geographical and customer density characteristics. PPL is largely rural in nature, and is required to run distribution lines along every public road and also provide service to virtually every residence and business within its service territory. The same is not true for natural gas distribution companies that do not have this same service requirement.

Q. IS IT REASONABLE TO ALLOCATE DISTRIBUTION MAINS INVESTMENT ON THE BASIS OF ANNUAL AS WELL AS PEAK DEMANDS?

A. Yes. Distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand study. The basic reason why Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands.

SCALE BACK OF RATE LEVELS

Q. DID YOU ADDRESS THE COMPANY'S ORIGINAL REVENUE INCREASE BY CLASS BEFORE APPLICATION OF ANY SCALE BACK?

A. Yes. I recommended a revenue allocation that adjusted the Company's proposed revenue allocation by re-allocating $3,500,000 from the RSS/RDS rate group to the SGSS/SCD/SGDS and SDS/LGSS rate groups (I&E St. No. 3, p. 42, I&E Ex. No. 3, Sch. 11). My recommended revenue allocation, as well as my scale back recommendation, is consistent with the cost allocation methodology upon which they rely (Peak & Average).

Q. WHAT TYPE OF SCALE BACK DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE $46,171,228 REVENUE INCREASE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. I recommended a scale back of rates designed to reduce portions of the increases proposed for the RS/RDS, SGSS/SCD/SGDS, and SDS/LGSS rate groups as shown on I&E Exhibit No. 3, Schedule 12. In addition, I recommended that any further scale back over $40,258,200 be proportional to the percentage increases shown on I&E Exhibit No. 3, Schedule 13, line 22, excluding the MLDS class, since the Company has proposed no increase in base rates for this class (I&E St. No. 3, pp. 43-45). My scale back recommendation as shown on I&E Exhibit No. 3, Schedule 12 is an effort to keep the relative rates of return for the RSS/RDS, SGSS/SCD/SGDS, and SDS/LGSS rate groups as close to one another as possible and to bring the revenues received from each of these classes as close to the cost of providing service as possible.

Q. HAS THE COMPANY MADE ANY REVISIONS TO ITS REQUESTED BASE RATE REVENUE INCREASE OF $46,171,228?

A. Yes. As described in the rebuttal testimony of the Company, it has lowered the requested increase to $45,572,790 (Columbia St. No. 104-R, p. 2).

Q. DID THE COMPANY ALLOCATE THE REVISED $45,572,790 INCREASE TO THE VARIOUS CLASSES?

A. No. It appears that the Company has made no changes to its cost of service study based on its revised requested increase. Therefore, I was unable to revise my scale back recommendation to incorporate the Company's revised requested increase of $45,572,790.

Q. DID THE COMPANY PROVIDE ANY SUPPORT OR JUSTIFICATION FOR ITS ASSERTION THAT YOUR SCALE BACK RECOMMENDATION SHOULD BE REJECTED?

A. No. The Company addressed my recommendation by simply stating that it is unnecessarily complicated, and that it prefers a proportional scale back of the increase for each rate class from its original proposed rate class revenue requirements (Columbia St. No. 111-R, pp. 18-19).

Q. IS YOUR SCALE BACK RECOMMENDATION UNNECESSARILY COMPLICATED?

A. No. I provide specific guidelines at various levels as to which class should be scaled back (I&E Ex. No. 3, Sch. 12).

Q. HAS ANY OTHER PARTY ADDRESSED YOUR SCALE BACK RECOMMENDATION?

A. Yes. PSU Witness Crist disagrees with my scale back recommendation (PSU St. No. 1-R, p. 5).

Q. WHY DOES PSU WITNESS CRIST DISAGREE WITH YOUR RECOMMENDATION?

A. PSU witness Crist's disagreement is based on my reliance on the results of the Company's Peak and Average cost of service study, and on his belief that scale back must occur first in the LDS class so that the portion of increase that would be assigned to flex customers (who will not bear any increase) be scaled back. Mr. Crist claims that since there is already exists an issue of flex customers in the LDS class, shifting the weight of the average of the Company's two cost of service studies, relied upon by the Company, to the Peak & Average study further increases the burden to the non-flex customers in the LDS class (PSU St. No. 1-R, pp. 5-6).

Q. WHAT IS YOUR RESPONSE TO THESE CRITICISMS OF YOUR USE OF THE PEAK AND AVERAGE COST OF SERVICE STUDY TO DETERMINE A PROPER SCALE BACK OF RATES?

A. I continue to support use of the Peak and Average study. As stated previously, Company witness Elliott and OSBA witness Knecht have both recognized that the Commission generally considers a cost of service method which treats the costs of distribution mains without recognizing a customer component as the most useful guide in allocating revenue requirement. Therefore, the Company's Peak & Average study should be used to allocate a scale back of rates if the Commission grants less than the full increase in rates. While Mr. Crist may disagree with the Peak and Average methodology, his position lacks Commission support.

Q. HAVE YOU PREVIOUSLY ADDRESS THE CONCERNS OF MR. CRIST REGARDING YOUR SCALE BACK RECOMMENDATION AND THE COST OF FLEX RATE SHORTFALLS?

A. Yes. I have addressed Mr. Crist concerns regarding flex rate customers in my rebuttal testimony (I&E St. No. 3-R, pp. 4-11).

Q. DO YOU CONTINUE TO BELIEVE THAT YOUR SCALE BACK RECOMMENDATION AS PRESENTED IN YOUR DIRECT TESTIMONY IS REASONABLE?

A. Yes. As explained in my direct testimony, the relative rate of return is a comparison of the rate of return for each class compares to the system average rate of return. For example, at present rates, the RSS/RDS rate of return is 6.58 percent, compared to a system average rate of return of 6.06 percent, implying a relative rate of return of 1.09 (6.58 / 6.06). A relative return of 1.0 implies that a class is exactly recovering its allocated costs. A relative return below 1.0 implies that the class is under-recovering its costs. A relative return above 1.0 implies that the class is over-recovering its allocated costs. If a class exhibits a relative rate of return that is closer to 1.0 at proposed rates than it is a present rates, that class is making progress toward cost-based rates. My scale back recommendation, illustrated on I&E Exhibit No. 3, Schedule 12, to be applied subsequent to my recommended revenue allocation of the Company's total requested increase should the Commission approve less than the requested increase, maintains a relative rate of return that is reasonable at any revenue level the Commission permits the Company the opportunity to recover.

CHOICE ADMINISTRATION CHARGE RIDER ("RIDER CAC")

Q. WHAT RECOMMENDATION DID YOU MAKE REGARDING THE COMPANY'S RIDER CAC IN DIRECT TESTIMONY?

A. In direct testimony I objected to the Company's proposed Rider CAC and recommended that the Company continue to recover through distribution rates costs that Columbia proposes to be included in Rider CAC (I&E St. No. 3, pp. 56-58).

Q. IN REBUTTAL TESTIMONY, DOES COMPANY WITNESS KRAJOVIC EXPLAIN HER RATIONALE FOR PROPOSING RIDER CAC?

A. Yes. Ms. Krajovic claims that a CAC rider is necessary because Columbia is following the lead the Commission set in establishing the GPC by further unbundling rates, thus the CAC rider is merely assigning the costs required to make available the CHOICE program to CHOICE customers (Columbia St. No. 112-R, p. 19).

Q. IS THERE ANYTHING IN THE COMMISSION RULES THAT DIRECTS COLUMBIA TO ASSIGN SPECIFIC COSTS TO CHOICE CUSTOMERS ONLY?

A. No. Unlike 52 Pa. Code §62.223 which requires Columbia to assign costs to a gas procurement charge, there is no Commission rule that I am aware of that authorizes Columbia to assign costs just to CHOICE customers.

Q. MS. KRAJOVIC OPINES THAT LAUNCHING A NEW RIDER TO PLACE COSTS ON TRANSPORTATION CUSTOMERS IS IN THE INTEREST OF UNBUNDLING RATES AS INITIATED IN DOCKET NO. L-2008-2069114. IS THAT ACCURATE?

A. No. In the referenced proceeding the Commission modified Section 62.223 of 52 Pa. Code to clarify the costs that are appropriate to assign to the gas procurement charge. The purpose of the Commission Order in that proceeding was to promote effective competition for natural gas supply. The Commission expressed concern that "effective competition" did not exist. As the Report to the General Assembly noted:

> Based on the factors we have adopted to consider whether "effective competition" exists for purposes of Section 2204(g), these findings support the ultimate conclusion that there is a lack of "effective competition" in Pennsylvania's retail natural gas supply market at this time.[1]

That concern was noted in 2005. In 2008 the Commission ordered several actions to improve competition. It directed that costs be shifted from delivery rates to commodity rates. Columbia advocated similar concepts to what it proposes in Rider CAC and was not convincing just as Ms. Krajovic's claims are not convincing here. The Final Rulemaking Order issued January 13, 2011 states:

> In its comments, Columbia argues that NGDCs incur costs that are solely related to NGSs' service, but fails to demonstrate adequately that these costs are unique to NGS service. Columbia contends that, even if they left the merchant function, these costs would continue to be incurred. However, Columbia fails to note that many of these same costs are needed to provide both SOLR <u>and</u> competitive service. Moreover, none of these costs are included in the list of specific and limited costs which the Commission has proposed to unbundle from distribution service. (p. 19-20)

[1] *The Report to the General Assembly* was released in October 2005 at Docket No. I-00040103.

Columbia, now is merely trying to do with the CAC what the Commission rejected when determining the costs for the GPC.

Q. DO YOU AGREE WITH MS. KRAJOVIC'S RATIONALE FOR PROPOSING THE CAC RIDER?

A. No. With the CAC Rider Columbia is attempting to assign to CHOICE customers the costs Columbia deems are required to support the CHOICE program. However, outside the direct gas supply costs that are being assigned to the sales customers through the GPC, Columbia does not assign any other non-gas costs required to support sales service. Even if the non-gas costs required to support the sales product are being utilized to support distribution service, it does not change the fact that they are also being utilized to support sales service. So until Columbia fully unbundles all of its costs utilized to support sales service, Columbia should not selectively assign costs it deems necessary to support the CHOICE program only to CHOICE customers.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 3-SR
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

Exhibit to Accompany

the

Surrebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:
Rate Base
Present Rate Revenues
Cost of Service
Scaleback
Customer Cost Analysis
Customer Charges
CAC Rider

I&E Exhibit No. 3-SR
Schedule 1

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2015-2468056
Summary of Increase to Present Rate Revenues Per BI&E
Fully Projected Future Test Year Ending December 31, 2016

	Customer Class	Company Claim	BI&E Proposed Adjustment	Adjusted Revenue Per BI&E
	(A)	(B)	(C)	(D)
		Co. Ex. No. 103 Schedule 1 pp. 13-18		
	RESIDENTIAL CUSTOMERS			
	RSS - Residential Sales Service			
1	Non - Gas Revenues	$175,175,056	$3,238,462	$178,413,518
2	Gas Procurement Charge	$1,618,007	$53,413	$1,671,420
3	Merchant Function Charge	$1,573,774	$51,953	$1,625,727
4	Gas Costs	$125,461,892	$4,141,723	$129,603,615
5	STAS	$0	$0	$0
6	Total RSS Present Rate Revenue	$303,828,729	$7,485,551	$311,314,280
	RDS - Residential Distribution Service (Choice)			
7	Non - Gas Revenues	$59,360,495	$0	$59,360,495
8	Gas Costs	$5,910,184	$0	$5,910,184
9	STAS	$0	$0	$0
10	Total RDS Present Rate Revenue	$65,270,679	$0	$65,270,679
	RCC - Residential Distribution Service (CAP)			
11	Non - Gas Revenues	$14,899,363	$0	$14,899,363
12	Gas Costs	$1,825,927	$0	$1,825,927
13	STAS	$0	$0	$0
14	Total RCC Present Rate Revenue	$16,725,290	$0	$16,725,290
15	**Total Residential Present Rate Revenue (Lines 6+10+14)**	$385,824,698	$7,485,551	$393,310,249
16	**Total Residential Gas Cost (Lines 4+8+12)**	$133,198,003	$4,141,723	$137,339,726

I&E Exhibit No. 3-SR
Schedule 2

Columbia Gas of Pennsylvania, Inc.
BI&E Proposed Present Rate Revenues and Cost of Gas
Residential Customers
For the Twelve Months Ending December 31, 2016

		Per Company						Per BI&E				
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Description	Bills	Total Normal Usage (Dth/cust.)	Total Consumption (Dth)	Base Rate ($/Dth)	Revenue ($)	Increase to Present Rate Revenues ($)	Bills	Total Normal Usage (Dth/cust.)	Total Consumption (Dth)	Base Rate ($/Dth)	Revenue ($)
		Columbia Ex 103 Schedule No. 1		*Columbia Ex 103 Schedule No 1*								
1	Rate Schedule RSS - Residential Sales Service											
2		277,800 customers	83.80	23,280,676.1				277,800 customers	86.57	24,049,213.2		
3	Customer Charge	3,377,134			16.75	56,566,995		3,377,134			16.75	56,566,995
4	Commodity Charge											
5	All Gas Consumed			23,280,676.1	4.2138	98,100,113	$3,238,462			24,049,213.2	4.2138	101,338,575
6	Rider USP - Universal Service Plan			23,280,676.1	0.8800	20,486,995				23,280,676.1	0.8800	20,486,995
7	Rider CC - Customer Choice			23,280,676.1	0.0009	20,953				23,280,676.1	0.0009	20,953
8	Gas Procurement Charge			23,280,676.1	0.0695	1,618,007	$53,413			24,049,213.2	0.0695	1,671,420
9	Subtotal					176,793,063						180,084,938
10	STAS					0						0
11	Base Rate Revenue					176,793,063						180,084,938
12	Gas Cost			23,280,676.1	5.3891	125,461,892	$4,141,723			24,049,213.2	5.3891	129,603,615
13	Merchant Function Charge			23,280,676.1	0.0676	1,573,774	$51,953			24,049,213.2	0.0676	1,625,727
14	Total Rate Schedule RSS	3,377,134		23,280,676.1		303,828,729		3,377,134				311,314,280
15	Rate Schedule RDS - Residential Distribution Service (Choice)											
16		90,361 customers	90.02	8,134,026.3				90,361 customers	90.02	8,134,026.3		
17	Customer Charge	1,069,855			16.75	17,920,071		1,069,855			16.75	17,920,071
18	Commodity Charge:											
19	All Gas Consumed			8,134,026.3	4.2138	34,275,160				8,134,026.3	4.2138	34,275,160
20	Rider USP - Universal Service Plan			8,134,026.3	0.8800	7,157,943				8,134,026.3	0.8800	7,157,943
21	Rider CC			8,134,026.3	0.0009	7,321				8,134,026.3	0.0009	7,321
22	Choice Administration Charge			8,134,026.3	0.0000	0				8,134,026.3	0.0000	0
23	Subtotal					59,360,495						59,360,495
24	STAS					0						0
25	Base Rate Revenue					59,360,495						59,360,495
26	Gas Cost			8,134,026.3	0.7266	5,910,184				8,134,026.3	0.7266	5,910,184
27	Total Rate Schedule RDS	1,069,855		8,134,026.3		65,270,679		1,069,855		8,134,026.3		65,270,679
28	Rate Schedule RCC - Residential Distribution Service (CAP)											
29		19,872 customers	126.46	2,512,973.7				19,872 customers	126.46	2,512,974		
30	Customer Charge	257,325			16.75	4,310,194		257,325			16.75	4,310,194
31	Commodity Charge											
32	All Gas Consumed			2,512,973.7	4.2138	10,589,169				2,512,973.7	4.2138	10,589,169
33	Subtotal			2,512,973.7		14,899,363				2,512,973.7		14,899,363
34	STAS					0						0
35	Base Rate Revenue					14,899,363						14,899,363
36	Gas Cost			2,512,973.7	0.7266	1,825,927				2,512,973.7	0.7266	1,825,927
37	Total Rate Schedule RCC	257,325		2,512,973.7		16,725,290		257,325		2,512,973.7		16,725,290
38	Total Residential	388,033 customers	87.44	33,927,676.1		385,824,698	$7,485,551	388,033 customers	89.42	34,696,213		393,310,249

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, Jeremy B. Hubert, hereby state that the facts set forth in the foregoing document, I&E Statement No. 3-SR and I&E Exhibit No. 3-SR, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/15
Date

Jeremy B. Hubert
Jeremy B. Hubert

I&E Statement No. 4 Revised
Witness: David Kline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

REVISED

Direct Testimony

of

David Kline

Bureau of Investigation & Enforcement

Concerning:

PIPELINE REPLACEMENT

PIPELINE REPLACEMENT COSTS

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

A. My name is David D. Kline. I am a Gas Safety Engineer in the Gas 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, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. I attended the Pennsylvania State University and earned a Bachelor's of Science Degree in Civil Engineering in 2007. I joined the Pennsylvania Public Utility Commission's Gas Safety Division in June of 2008.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address Columbia Gas of Pennsylvania, Inc. ("CPA" or "Company") pipeline replacement of bare steel, cast iron, wrought iron, and vintage plastic pipe also known as first generation pipe. My direct testimony addresses the following issues:

A. Federal regulations CPA is required to follow
B. Pipeline replacements of bare steel
C. Active corrosion and CPA's active corrosion program
D. Pipeline Replacement Costs

Q. WHAT FEDERAL REGULATIONS IS CPA REQUIRED TO COMPLY WITH THAT AFFECT PIPELINE REPLACEMENTS?

A. CPA is mandated to adhere to the Distribution Integrity Management Program or DIMP under Chapter 49 Part 192.1001-192.1015 of the Code of Federal Regulations.

Q. WHAT DOES DIMP REQUIRE?

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
6. Report the results

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

Q. HAVE YOU REVIEWED CPA'S WITNESSES MR. KEMPIC'S DIRECT TESTIMONY AND MR. DAVIDSON'S DIRECT TESTIMONY AS IT RELATES TO ACTIVITIES DESIGNED BY CPA TO IMPROVE THE SAFETY AND RELIABILITY OF CPA'S NATURAL GAS DISTRIBUTION SERVICE?

A. I have reviewed Mr. Kempic's direct testimony. Mr. Kempic summarizes CPA's safety and reliability improvement activities[1]. I also reviewed Mr. Davidson's direct testimony[2] () regarding the Company's annual pipeline replacement activities and enhanced operations and maintance activities.

Q. WHAT IS YOUR REACTION TO CPA'S TESTIMONY REGARDING PIPELINE REPLACEMENT ACTIVITIES AND OPERATION AND MAINTENANCE (O&M) ACTIVITIES?

A. The Company's activities are based on the top threats to its facilities based on: (1) the DIMP regulations; (2) pipeline safety issues that have been identified by the Pipeline and Hazardous Materials Safety Administration (PHMSA); and (3) violations uncovered by the PUC Gas Safety Division. CPA must implement these pipeline replacement and O&M activities based on its DIMP plan to reduce the risk to the Company's system as required under DIMP regulations. DIMP compliance is not optional.

[1] Company Statement No. 1, pages 6-14.
[2] Company Statement No. 15

Q. WHY MUST A NATURAL GAS OPERATOR COMPLY WITH DIMP?

A. PHMSA created DIMP regulations to reduce the number of Department of Transportation (DOT) reportable incidents[3]. Pipeline leaks from corrosion and third party damages[4] are two of the main causes of reportable incidents.

Q. IN YOUR OPINION, DOES DIMP CALCULATED RISK DECREASE AS THE PIPELINE OPERATOR INVESTS ADDITIONAL DOLLARS INTO RISK MITIGATION?

A. No. A decrease in DIMP calculated risk depends on whether an appropriate amount of dollars were used to mitigate risk properly. A well designed DIMP plan will examine the benefits of additional dollars to mitigate risk and where those dollars should be invested in order to maximize the greatest reduction to risk. CPA has determined in its DIMP plan that in order to mitigate risk associated with corrosion, CPA must replace its risky pipe. CPA's risky pipe is cast iron and unprotected bare steel. CPA believes that pipeline replacement is the optimal method for reducing overall risk to the CPA distribution system.

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[3] 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 $50,000 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.

[4] Third Party Damages are defined as damages to natural gas facilities (or other such underground facilities) caused by someone other than the operator or the operator's contractor.

Q. CAN CPA DEMONSTRATE RISK REDUCTION PER DOLLARS SPENT ON PIPELINE REPLACEMENT?

A. Yes. CPA's response to I&E-GS-001[5] shows the Company's OPTIMAIN risk score for all the projects replaced in 2014. CPA divided the risk reduction score (the difference between the calculated pre 2014 and post 2014 risk scores) by the total capital spent in 2014 to demonstrate that the Company's risk score was reduced by 110 points per million dollars spent. OPTMAIN software is the Company's computer program that calculates a risk score on each segment of pipe for CPA's DIMP program. The Company replaced 78 miles of pipe in 2014 with a combined risk score of 16,343.

Q. DOES CPA HAVE LIMITLESS ACCESS TO CAPITAL TO REPLACE RISKY PIPELINES?

A. No. As with any public utility, the cost of borrowing funds for pipeline replacement is limited by capital budgets and subsequent rate recovery.

Q. IF CAPITAL IS UTILIZED FOR ANCILARY COSTS SUCH AS RESTORATION COSTS, DOES THAT COST REDUCE THE FUNDS AVAILABLE FOR PIPELINE REPLACEMENT?

A. Obviously yes. The less money the Company spends on restoration costs, the more funds it has for pipeline replacement.

[5] I&E Exhibit No. 4, Schedule 8

Q. IN THE RESPONSE TO I&E-GS-1, DOES THE COMPANY IDENTIFY OTHER FACTORS THAT AFFECT THE MARGINAL BENEFIT DERIVED BY INVESTINGING CAPITAL TO REDUCE RISK?

A. Yes. The Company identifies in I&E-GS-1[6] that there are many other factors that can contribute to risk that make it difficult to calculate the marginal benefit for every million dollars spent. They include: leaks on remaining pipe, weighting of risk factors are revisited regularly, data quality and risk modeling are constantly being improved, and performance of tasks that are not captured in the software, such as the installation of excess flow valves.

Q. IS THERE ANOTHER WAY TO COMPARE RISK REDUCTION THAN ON COST BASIS?

A. In my opinion, yes. Another method to compare risk reduction is to examine how many miles of risky pipeline were replaced/abandoned with the total CPA capital budget. CPA's response to Gas Safety's form letter FL-1-15[7] question 18[8], shows that the company replaced or abandoned 106.77 miles of priority pipe. The total risk score reduction for these segments of pipe from the Company's OPTIMAIN software was 16,343. Therefore, for every mile of pipe the Company replaced or abandoned in 2014, the risk score was reduced by 153 points per mile of pipeline

[6] I&E Exhibit No .4, Schedule 8
[7] I&E Exhibit No. 4, Schedule 7
[8] I&E Exhibit No. 4, Schedule 6

replaced or abandoned. This demonstrates the Company has a variety of options in reducing its risk with regard to pipeline.

Q. MR. DAVIDSON STATES IN HIS DIRECT TESTIMONY ON PAGE 20 THAT CPA HAS REPLACED MORE BARE STEEL MAINS THAN THE OTHER REGULATED NATURAL GAS DISTRIBUTION COMPANIES IN PENNSYLVANIA. IS THAT STATEMENT ACCURATE?

A. Yes

Q. DISCUSS CPA'S BARE STEEL REPLACEMENT.

A. While Columbia emphasizes that it has replaced more miles of bare steel than its peers, it is important to note that Columbia has more miles of bare steel in the ground than most of its peers. Columbia has the second highest amount of bare steel remaining in operation of all regulated public natural gas utilities in Pennsylvania[9]. For example, in 2014 Columbia had 1,529 miles of bare steel pipeline in service while PECO had 327 miles of bare steel pipeline in service. Therefore, it is logical that Columbia is replacing more miles than PECO given that CPA has almost five times as much bare steel remaining in 2014.

Q. WHY IS CPA REPLACING BARE STEEL PIPELINES AT AN ACCELERATED PACE?

[9] I&E Exhibit No. 4, Schedule 1

A. From 2008-2014, Columbia had the highest or the second highest amount of miles of bare steel remaining in operation of all regulated public natural gas utilities in Pennsylvania[10]. Additionally, CPA had the highest corrosion leaks repaired per mile of cast iron and unprotected bare and coated steel in Pennsylvania in 2008 and the second highest in 2006, 2007, 2009, 2010 and 2011, 2013, and 2014 and the third highest in 2012[11].

Q. **MR. KLINE, IS THERE AN ALTERNATE METHOD TO COMPARE BARE STEEL PIPELINE REPLACEMENT MILES?**

A. Yes. Rather than comparing miles of bare steel replaced between the utilities, it is worthwhile to look at the percentage of bare steel each LDC has replaced. From 2002-2014, CPA replaced 34% of its bare steel; however, Peoples TWP LLC replaced 47%, National Fuel Gas Distribution (NFG) replaced 22%, (This number changed in 2012 when NFG updated legacy maps to a GIS system that contains more accurate information), UGI Penn Natural Gas replaced 57%, and UGI Utilities, Inc. replaced 24%[12]. Therefore, when looking at the amount of bare steel replaced compared to the amount of bare steel in the ground, it is clear that CPA is not ahead of its peers.

[10] I&E Exhibit No. 4, Schedule 1
[11] I&E Exhibit No. 4, Schedule 3
[12] I&E Exhibit No. 4, Schedule 1.

Q. DOES MR. DAVIDSON PROVIDE A CHART TO COMPARE PENNSYLVANIA NATURAL GAS DISTRIBUTION UTILITIES' PIPELINE REPLACEMENT MILES? PLEASE DISCUSS.

A. Yes. Mr. Davidson's Statement No. 15, page 19 and 20 provides a chart comparing Columbia to some of the other gas distribution utilities in the state. CPA compared the number of bare steel miles remaining in its system based on DOT reports from 2009 to 2013 for the other utilities listed. Using the DOT pipeline data in this chart to make a comparison to other utilities based on this information alone is problematic because gas utilities are not consistent as to how assets are recorded, mapped or identified, which could increase or decrease their annual mileage and not reflect accurately on the total amount of bare steel that was replaced in a pipeline system. Two examples of this would be in 2011 UGI Utilities reported a total of 368 miles of bare steel in the system and in 2012 that number went up to 392 miles. The second example would be that in 2011 National Fuel reported 966 miles and in 2012 reported 1,063 miles of bare steel pipe. The numbers Columbia provided in this chart show that, for a four year average, UGI only replaced 4 miles per year. From 2009 to 2011 UGI's bare steel decreased by 23 miles, which shows a higher average than what is displayed in Mr. Davidson chart, and does not accurately reflect what the company replaced.

Q. IS THERE ANOTHER FACTOR OTHER THAN TOTAL MILES OF RISKY PIPE THAT DETERMINES HOW A UTILITY REPLACES RISKY PIPE?

A. Yes. DIMP also guides what a gas utility must replace. DIMP is a living breathing document that can change daily as new risks are identified and old risks are mitigated. For example, CPA identified its riskiest pipe, bare steel, as the greatest threat while another utility may identify cast iron pipe as its highest threat and focus company resources on replacing that threat.

Q. REMOVED.

A. REMOVED.[13]

[13] Removed.

REMOVED.

Q. IN YOUR OPINION, WHY DID CPA ACCELERATE ITS PIPELINE REPLACEMENT?

A. In my opinion, Columbia accelerated its pipeline replacement because of previous historically poor performance in this area that resulted in an increase in corrosion leaks repaired per mile. In fact, CPA's leak per mile rate more than doubled from 2002 to 2008 and is still slightly less than double the 2002 leak per mile rate[14]. One of these corrosion leaks led to a reportable incident in 2006. The corrosion occurring on bare steel pipe causes a safety risk to the public. The best way the Company can reduce this risk is through pipeline replacement at an accelerated rate.

[14] I&E Exhibit No. 4 Schedule 3

Q. MR. DAVIDSON IDENTIFIED SAFETY ACTIONS THE COMPANY HAS TAKEN THAT HE CHARACTERIZES AS "ENORMOUS PROGRESS SINCE 2006 IN DELIVERING AND MAINTAINING A SAFE AND RELIABLE DISTRIBUTION SYSTEM FOR ITS CUSTOMERS." HOW WOULD YOU CHARACTERIZE THESE ACTIONS?

A. I would characterize the Company's actions as required by DIMP and reflective of the need to improve its pipeline replacement program. On page 18 of his testimony, Mr. Davidson states the Company is initiating an annual leakage survey of all bare steel mains, identification and mitigation of cross bores, and reducing the backlog of Type 2 leaks. The annual leakage survey on bare steel mains is above and beyond the requirements of 49 CFR Part 192 and will help the Company identify the leaks sooner. 49 CFR Part 192.723 requires a company to leak survey bare steel once every three years. Annual leakage surveys will help the company identify leaks before they have the possibility of becoming hazardous.

The Company has also identified cross bores as a risk to its system. The cross bore of gas lines through other pipes is usually caused by using trenchless technology to install the gas lines in the ground and not exposing any other existing lines. Cross bores have the potential to cause a serious hazard to the public. If a homeowner calls a plumber because his sewer line is plugged, the plumber can run a drain cleaning tool through the sewer line, and if there is a gas line in the sewer line, can cut through the gas line. The cut gas line would put gas into the sewers and has the potential to put gas inside the homes of the entire neighborhood.

CPA is also reducing the number of open Type 2 leaks. This helps the Company eliminate potential for water to enter the system, reduce its lost and unaccounted for gas rate, and also be able to reduce the number of odor complaints the company receives. Although, in the response to I&E-GS-8[15] at the end of December 2014 the Company had 1,713 open Type 2 leaks and the Company's response to I&E-GS-2[16] in the 2014 rate case[17] proceeding showed the company had 1,593 Type 2 leaks at 12/31/13. This is an increase of 120 leaks from 2013 to 2014.

I would characterize the above actions as items required by DIMP and reflective of the need to improve its pipeline replacement program. As discussed above, CPA had a history of corrosion and increasing leak per mile rate prior to 2007. Therefore, while CPA has made progress since 2006, that progress was either required by the DIMP or developed to address concerns identified by the Commission's Gas Safety Division.

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[15] I&E Exhibit No. 4, Schedule 9
[16] I&E Exhibit No. 4, Schedule 10
[17] Docket No. R-2014-2406274

Q. ARE THERE ANY OTHER SAFETY ACTIONS THE COMPANY SHOULD TAKE?

A. Yes. In my opinion, along with reducing the number of open Type 2 leaks, the Company should also be focusing its attention on fixing the increasing backlog of Type 3 leaks. The Company's response to I&E-GS-8[18] shows at the end of 2014 the Company had 6,700 active Type 3 leaks which represented 80 % of the total active leaks. During the 2014 rate case proceeding the Company's response to I&E-GS-2[19] reported 6,393 Grade 3 leaks. The Type 3 backlog of active leaks increased by 307 leaks from the end of 2013 to the end of 2014. The Company's response to I&E-GS-9[20] shows that currently there is 6921 Grade 3 leaks open, an increase of 221 leaks since December of 2014. While most of these leaks may be located in remote areas of the Company's system, they can still cause a threat to the public. While it is not required by regulations, the goal of all pipeline operators should be to fix all leaks, no matter what the classification.

Q. HOW DOES COLUMBIA'S LONG TERM INFRASTRUCTURE IMPROVEMENT PLAN (LTIIP) ADDRESS PIPELINE REPLACEMENT?

Columbia filed its LTIIP with the Commission in 2012 at Docket No. P-2012-2338282. Columbia averred in the LTIIP filing that it experienced an increasing number of leaks in areas with high concentration of aging pipe. Columbia stated

[18] I&E Exhibit No. 4, Schedule 9
[19] I&E Exhibit No. 4, Schedule 10
[20] I&E Exhibit No. 4, Schedule 12

that its corrosion leaks represented 85% of all leakage that occurs on main lines in its system. Columbia stated in the LTIIP that removal of bare steel and cast iron pipe will reduce the Company's leakage based on corrosion.

Q. WHAT TIME FRAME IS GIVEN IN THE LTIIP PLAN FOR PIPELINE REPLACEMENT?

A. Columbia states in the LTIIP that the Company will replace all the bare steel and cast iron pipe in 17 years or by 2029. In order to complete this process the Company must replace or retire on average, 98 miles of pipe per year from the date this plan was filed, 12/1/12. Using the numbers from the company's DOT reports CPA replaced 90 miles in 2012, 85 miles in 2013, and 78 miles in 2014. At the current pace, CPA will not meet its plan of a 17 year target date.

Q. BASED ON CPA'S LTIIP PLAN, HOW DOES THE COMPANY PLAN ON REDUCING COST OF PIPELINE PROJECTS?

A. CPA stated in the LTIIP that the Company would coordinate work with state and municipal improvements to reduce the cost of projects. The Company also stated that it was Columbia's plan to replace large segments of the system to reduce disruption to customers and municipalities. Finally, the company stated that it uses a competitive bidding process to drive down the cost of time and materials.

Q. WHAT IS COLUMBIA'S COST PER MILE OF PIPE REPLACEMENT COMPARED TO THE OTHER UTILITIES IN THE COMMONWEALTH?

A. The Safety Gas Division asked for utilities to provide the 2014 actual and budgeted dollars and miles of pipe replacement in 2014. This information was requested in form letter FL-1-15[21] that the Gas Safety Division sends out to all gas utilities in the beginning of each year. Columbia filed its responses to FL-1-15 in March 2014 that included data from 2014; however, Columbia did not include the 2014 data in the present rate case interrogatory I&E-GS-11.

As can be seen in Attachment A of the Company's response to I&E-GS-20[22] from the 2014 rate case proceeding, Columbia's cost per mile in 2012 was $716,358. The information the Company submitted for 2013 to the Gas Safety Division was $1,651,849 per mile.[23] This price is more than double what the Company was paying per mile in 2012. In 2014 the Company's replacement cost was $1,892,846, an increase of $240,997.[24] Between 2013 and 2014 the mileage the Company replaced decreased almost 7 miles, but the price increased per mile of pipe. In the Settlement document of Docket No. R-2014-2406274 at Paragraph 39, CPA stated that would work to reduce restoration fees, but the Company's pipeline replacement costs are continuing to increase. In 2012 paving costs

[21] I&E Exhibit No. 4, Schedule 7
[22] I&E Exhibit No. 4, Schedule 11
[23] I&E Exhibit No. 4, Schedule 4
[24] Removed.

represented almost 18% of the total budget and in 2013 paving costs represented almost 23% of the total budget[25] an increase of 5% from 2012 to 2013.

Q. IN THE SETTLEMENT DOCUMENT OFDOCKET NO. R-2014-2406274 DID THE COMPANY AGREE TO MEET WITH THE GAS SAFETY DIVISION TO GO OVER PIPELINE REPLACEMENT EXPENSE?

A. Yes. In the Settlement document of Docket No. R-2014-2406274 at Paragraph 38, Columbia agreed to meet with the Commission's Gas Safety Division and any other interested parties to discuss any state, county or municipality that exceeded Pennsylvania Department of Transportation restoration standards in order to coordinate responses to such actions.

Q. HAVE THESE MEETINGS OCCURRED?

A. No.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. The Company should not use the Annual DOT reports to compare how many miles of bare steel and cast iron it replaced compared to the other large operators in the state. Columbia should continue to reduce pipeline replacement and restoration costs. The Company should continue to reduce the number of Type 2 leaks along with reducing the backlog of Type 3 leaks as well.

[25] I&E Exhibit No. 4, Schedule 13

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

I&E Exhibit No. 4 Revised
Witness: David Kline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2015-2468056

REVISED

Exhibit to Accompany

the

Direct Testimony

of

David Kline

Bureau of Investigation & Enforcement

Concerning:

PIPELINE REPLACEMENT

PIPELINE REPLACEMENT COSTS

Miles of Bare Steel Remaining and Replaced by Columbia

I&E Exhibit No. 4
Schedule 1

Year	Remaining	Replaced
2002	2311	
2003	2280	31
2004	2350	-70
2005	2317	33
2006	2222	95
2007	2116	106
2008	2021	95
2009	1958	63
2010	1902	56
2011	1751	151
2012	1673	78
2013	1597	76
2014	1529	68

Miles of Bare Steel Remaining and Replaced by Ten Largest Distribution Utilities in Pennsylvania

Utility / Year	2002 Remaining	2008 Remaining	2009 Replaced	2009 Remaining	2010 Replaced	2010 Remaining	2011 Replaced	2011 Remaining	2012 Replaced	2012 Remaining	2013 Replaced	2013 Remaining	2014 Replaced	2014 Remaining	Total Replaced 2009-2014	Total Replaced 2002-2014	% Replaced 2002-2014
Columbia	2311	2021	63	1958	56	1902	151	1751	78	1673	76	1597	68	1529	492	782	34%
Peoples	2080	1939	22	1917	11	1906	22	1884	19	1865	12	1853	-684	2537	-598	-457	-22%
Equitable	962	803	22	781	19	762	25	737	24	713	4	709	N/A	0***	N/A	N/A	N/A
National	1302	1073	38	1035	36	999	33	966	-128	1094	31	1063	22	1041	32	261	20%
PECO	416	374	7	367	6	361	6	355	4	351	22	329	2	327	47	89	21%
PGW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UGI	474	398	7	391	12	379	11	368	-24	392	16	376	14	362	36	112	24%
UGI CPG	763	660	22	638	10	628	9	619	7	612	10	602	40	562	98	201	26%
UGI PNG	336	301	3	298	9	289	6	283	4	279	9	270	125	145	156	191	57%
Peoples TWP	1456	1066	54	1012	20	992	37	955	9	946	150	796	24	772	294	684	47%

** These numbers are taken from the Annual DOT reports pipeline operators are required to follow. Some of these companies have changed the way assests are classified and the numbers have changed on the Annual reports that show an increase or decrease in bare steel totals.

*** In 2014 Equitable Gas and Peoples Natural Gas are now reported under one company

I&E Exhibit No. 4
Schedule 2

Miles of Cast Iron Remaining and Replaced by Ten Largest Distribution Utilities in Pennsylvania

Utility / Year	2003 Replaced	2003 Remaining	2004 Replaced	2004 Remaining	2005 Replaced	2005 Remaining	2006 Replaced	2006 Remaining	2007 Replaced	2007 Remaining	2008 Replaced	2008 Remaining
Columbia	0	83	5	78	1	77	3	74	2	72	4	68
Peoples	1	70	2	68	2	66	0	68	2	64	0	64
Equitable	3	60	9	51	3	48	1	47	0	47	0	47
National	2	100	2	98	3	95	2	93	2	91	4	87
PECO	9	869	9	860	13	847	11	836	7	829	9	820
PGW	21	1680	20	1680	16	1644	20	1624	17	1607	20	1587
UGI	10	456	14	442	8	434	6	428	10	418	6	412
UGI CPG	5	40	4	36	36		-26	28	3	25	3	22
UGI PNG	0	71	1	72	2	70	1	69	-73	142	7	135
Peoples TWP	0	0	0	0	0	0	0	0	0	0	0	0

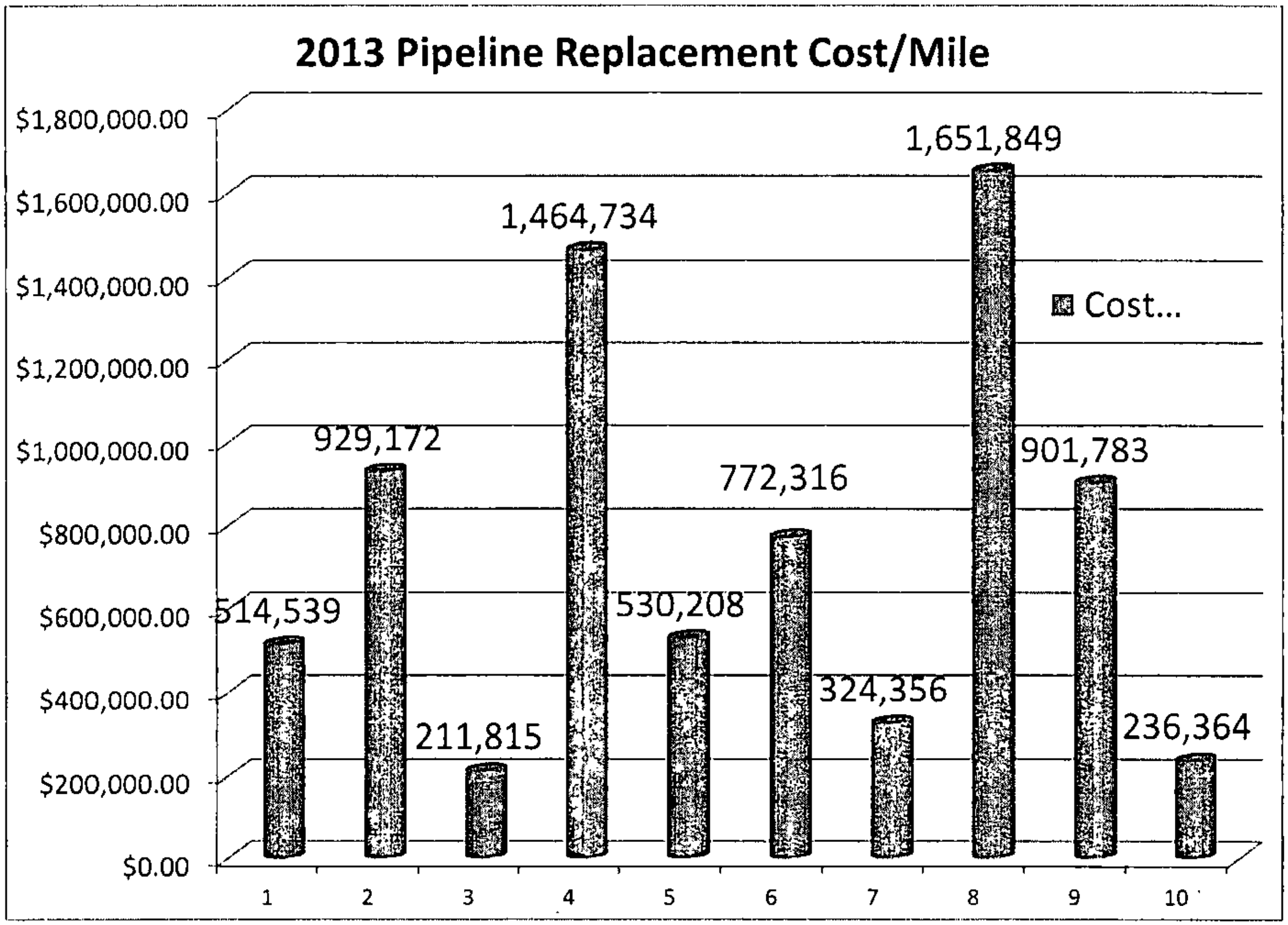
Utility / Year	2009 Replaced	2009 Remaining	2010 Replaced	2010 Remaining	2011 Replaced	2011 Remaining	2012 Replaced	2012 Remaining	2013 Replaced	2013 Remaining	2014 Replaced	2014 Remaining	Total Replaced 2002-2014	% Replaced 2002-2014
Columbia	4	64	3	61	2	159	12	147	9	138	10	128	(45)	-54%
Peoples	1	63	1	62	4	58	40	18	1	17	-92	109	(39)	-56%
Equitable	0	47	2	45	-62	107	6	101	5	96	0	0	60	100%
National	1	86	2	84	1	83	-92	175	6	169	3	166	(66)	-66%
PECO	9	811	12	799	13	786	27	759	25	734	20	714	155	18%
PGW	5	1582	20	1562	20	1542	18	1524	23	1501	28	1473	207	12%
UGI	12	400	13	387	21	366	18	348	32	316	37	279	177	39%
UGI CPG	2	20	2	18	2	16	3	13	2	11	11	0	40	100%
UGI PNG	9	126	4	122	5	117	6	111	2	109	3	106	(33)	-45%
Peoples TWP	0	0	0	0	0	0	0	0	0	0	0	0		

** These numbers are taken from the Annual DOT reports pipeline operators are required to follow. Some of these companies have changed the way assests are classified and the numbers have changed on the Annual reports that show an increase or decrease in cast iron totals.

I&E Exhibit No. 4
Schedule 3

Corrosion Leaks Repaired per Mile of Cast Iron and Unprotected Steel (Bare and Coated)

Utility / Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Columbia	0.88	1.08	1.18	1.25	1.40	1.55	2.05	1.64	1.56	1.45	1.53	1.26	1.50
Peoples	0.74	0.65	0.81	0.82	0.76	0.90	0.83	0.97	0.92	0.85	0.98	0.91	1
Equitable	1.18	1.26	1.79	1.26	0.84	0.89	0.78	0.79	0.91	0.70	0.75	0.70	0.00
National	1.27	1.08	1.04	1.25	1.32	1.16	1.17	1.29	1.35	1.02	0.81	0.81	0.93
PECO	1.98	1.38	1.82	2.30	1.81	1.83	1.71	1.88	2.40	2.19	2.19	2.98	3.48
PGW	0.01	0.05	0.05	0.06	0.07	0.06	0.08	0.11	0.10	0.09	0.07	0.09	0.07
UGI	1.39	1.47	1.15	1.26	0.71	0.78	0.72	0.94	0.79	0.80	1.02	0.85	1.11
UGI CPG	0.57	0.10	0.38		0.63	0.46	0.60	0.74	0.46	0.72	0.83	0.66	0.67
UGI PNG	1.42	1.24	1.13	1.35	1.28	1.12	1.24	1.10	1.50	1.39	1.61	1.03	0.92
Peoples TWP	0.67	0.56	0.75	0.96	0.97	1.21	1.16	1.29	1.17	0.95	1.08	0.53	0.59


2013 Pipeline Replacement Cost/Mile
$1,800,000.00
$1,600,000.00
$1,400,000.00
$1,200,000.00
$1,000,000.00
$800,000.00
$600,000.00
$400,000.00
$200,000.00
$0.00
514,539
929,172
211,815
1,464,734
530,208
772,316
324,356
1,651,849
901,783
236,364
Cost...
1
2
3
4
5
6
7
8
9
10

I&E Exhibit No. 4
Schedule 5

REMOVED

PIPE TYPE	AMOUNT ABANDONED IN 2014 (Miles)
Bare Steel	72.17
Pre-1982 Plastic	7.85
Plastic (1982 and newer)	13.51
1955-1970 Coated Steel	17.69
Pre-1955 Coated Steel	2.00
Coated Steel (1971 and newer)	4.11
Plastic Insert	0.00
Wrought Iron	2.50
Cast Iron	2.99
Other	0.08
Unknown Install Year Coated Steel	1.19
Unknown Install Year Plastic	0.29
TOTAL:	**124.39**

Total Optimain project risk scores eliminated in 2014 for Pennsylvania	16,343
Total miles of "priority" pipe abandoned in 2014: Excludes, *Plastic (1982 and newer), Coated Steel (1971 and newer) and Plastic Insert*	106.77
Optimain risk score eliminated per mile of "priority" pipe abandoned in 2014	**153.07**

The average risk score for High Priority Optimain projects increased from 56 to 69.

The average risk score for Low, Medium and High Priority Optimain projects increased from 31 to 34.

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

IN REPLY PLEASE REFER TO OUR FILE

January 27, 2015

REFERENCE:
FL-I-15

MR. MICHAEL HARJU
ABLE COMPANY
3189 JUNEAU ROAD
PUNSUTAWNEY PA 15767

Dear Mr. Harju:

Each year The Pennsylvania Public Utility Commission's Gas Safety Division enters into an agreement with the U.S. DOT Pipeline and Hazardous Materials Administration (PHMSA) to enforce the federal pipeline safety regulations. As such, PHMSA audits the Gas Safety Division each year. The PHMSA annual program evaluation is a review of the State agency's pipeline safety program. It includes an examination of State agency policies, plans, procedures, and records of the previous calendar year as well as the observation of the field inspection of a pipeline operator. The evaluation is usually conducted by the State Liaison Representative (SLR) from the Regional Office.

This year's evaluation includes questions that require the Gas Safety Division to investigate and collect data regarding plastic pipe failures, cast iron failures, damage prevention statistics, NTSB requirements, riser issues, DIMP and risk reduction, public awareness statistics, inside meter sets, pipeline replacement, and leak surveys.

In order to respond accurately and completely, the Gas Safety Division is requesting that all utilities refer to the Gas Safety webpage to download electronic schedule formats. The formats are created in Microsoft Excel and should be filed in the same format with this office. DO NOT FILE INFORMATION IN A PDF FORMAT. If there are any questions regarding the requested information, please contact this office for guidance.

1. Complete the Plastic Pipe Failure Template, located on the Gas Safety webpage. Also include a written explanation as to measures taken to mitigate any safety concerns.

2. Identify any and all cast iron pipe and component that has failed including bell joints; provide the reason for failure, date of the failure, information discovered from the investigation of the failure, and any actions the operator is taking to mitigate future failures, and provide the operator's procedures for determining if exposed cast iron pipe was examined for evidence of graphitization.

3. Provide your company's operating procedures for surveillance of cast iron pipelines, including appropriate action resulting from tracking circumferential cracking failures, study of leakage history, or other unusual operating maintenance condition.

4. Provide your company's operating procedures for abandoning pipeline facilities.

5. Provide your company's operating procedures for analyzing pipeline accidents to determine their cause.

6. Provide your company's operating procedures for emergency response as it relates to leaks caused by excavation damage near buildings and multiple leaks and underground migration of gas into nearby buildings.

7. Complete the Steel and Plastic Coupling Failure Template, located on the Gas Safety webpage. Identify any mechanical coupling failure related to mains and services on steel and plastic pipelines. Through 49 CFR 191.12, PHMSA requires a submitted form for F-7100.1-2, which per 49 CFR 192.1009, requires reporting of failed couplings resulting in hazardous leaks. PA PUC is requiring reporting of all mechanical coupling failures, regardless of resultant leak classification. Be sure to include the manufacturer of the failed coupling and the data for the type of main or service.

8. Complete the Damage Prevention Template, located on the Gas Safety webpage. Include in the data, pipeline damages by your own utility crews and your contractors.

9. Provide all documents supporting your company's public awareness actions during 2014. Also provide your company's evaluation of the public awareness programs. Provide a list of public awareness activities for 2014.

10. Provide your company's direction drilling/boring procedures (and your contractor procedures). Show how your procedures and your contractor's procedures include actions to protect your facilities from the dangers posed by drilling and other trenchless technologies.

11. Provide a list identifying all HCA's within your operating system. Provide the location and pipeline identification number.

12. Provide your company's drug and alcohol testing operator program rates and procedures for handling positive responses.

13. Participation in the plastic pipe data base reporting initiative is encouraged. Provide a discussion as to whether your company provided input to the PPDC.

14. Provide confirmation that your company submitted data to the National Pipeline Mapping System for transmission pipelines along with any changes made after the original submission.

15. Complete the Leak Survey Template located on the Gas Safety webpage.

16. Complete the Inside Meter Set Template located on the Gas Safety webpage.

17. Provide a schedule for the last five calendar years showing the (1) annual budgeted pipeline replacement miles (by pipeline type, i.e. cast iron, bare steel, services, etc.) and the estimated replacement cost; (2) the annual actual pipeline replacement miles (by pipeline type, i.e. cast iron, bare steel, services etc.) and actual replacement cost. Break down costs, budgeted and actual, into pipeline costs, service costs and improvements (i.e. street paving, curbing, sidewalks etc.)

18. Provide a schedule depicting the pipeline miles replaced by type, corresponding risk factor reduction, and a comparison of how your DIMP risk total decreased by project for calendar year 2014.

19. Provide a spreadsheet showing riser failures discovered during the last 3 years. Identify the riser manufacturer and whether the riser is owned by the customer or the utility. Provide a detailed discussion as to your utility's inclusion of riser failures in the DIMP.

20. Provide a spreadsheet identifying stray gas calls, location, and company procedures related to stray gas for calendar year 2014. Also, the Gas Safety Division has attached recommended procedures for stray gas issues. Detail how stray gas calls were resolved, include referenced procedures.

21. Provide a detailed schedule listing all pipe segments and miles of pipeline that were installed after 1971 that are coated but not cathodically protected. Also provide a discussion as to how these sections were identified in your DIMP or IMP plan and the operator's plan to mitigate this risk.

Please provide the requested information 30 calendar days from receipt of this letter. (If possible provide numbers 17 and 18 within 10 calendar days.)

This office is committed to ensuring that all natural gas companies comply with the provisions of the Public Utility Code. Therefore, you are advised that, if you fail to comply with the above requests this office will initiate all appropriate enforcement actions pursuant to the Public Utility Code against the utility and its officers, agents and employees.

Sincerely,

Paul J. Metro

Paul J. Metro, Manager
Gas Safety Division
Bureau of Investigation and Enforcement

Enclosure

PM: bb

PC: Johnnie Simms, Director, I&E
PA PUC Gas Safety Inspectors

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-001:

Provide a detailed schedule with supporting documents, that depict how Pipeline Safety Risk calculated by Columbia's Distribution Integrity Management Plan (DIMP) is reduced for each $1 million dollars spent on pipeline replacement.

Response:

The creation of a schedule to calculate the reduction in risk score for each $1 Million spent is not useful as it is not possible to establish a direct correlation between dollars spent on pipeline replacement and reduction of Pipeline Safety Risk. Specifically, the following factors that impact Pipeline Safety Risk are subject to continuous change: (1) additional leaks may be discovered on remaining pipe that continues to deteriorate; (2) weightings of risk factors are revisited regularly; (3) data quality and risk modeling tools are enhanced and improved and (4) there are risk reduction efforts that are not captured in the current risk score calculations (i.e, installing excess flow valves).

However, for the purposes of responding to this question, the following is a breakdown of the calculation for 2014:

Aggregate sum of Optimain® risk scores for 2014 completed projects:	16,343
Aggregate sum of Age & Condition Spend for 2014 ($000)	$148.3*
Risk Score Reduction/$1 million spent	110.2

*See Michael J. Davidson testimony/Statement No. 15/page 18 of 44

I&E Exhibit No. 4
Schedule 9

Question No. I&E-GS-008
Respondent: M. Davidson

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-008:

What percentage and number of the total active leaks are type 1, type 2 and type 3 at the December 31, 2014?

Response:

	# of Leaks	% of Total
Type 1	0	0%
Type 2	1713	20%
Type 3	6700	80%
Total	8413	100%

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2014-2406274

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-2:

Provide the percentage of total active leaks by type (type 1, type 2, and type 3) for the twelve months ending December 31, 2013.

Response:

The percentage of open Class 1 leaks on 12\31\2013 was 0%.

The percentage of open Class 2 leaks on 12\31\2013 was 20.1% (1593 open class 2s).

The percentage of open Class 3 leaks on 12\31\2013 was 79.9% (6393 open class 3 leaks).

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2014-2406274

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-20:

Provide a detailed schedule for the last 5 calendar years showing the total cost of pipeline replacement on a per mile basis including the following:

A. Each component of the total cost above (i.e. pipeline cost, labor, paving etc.);

B. All supporting documents that were utilized to determine the total cost per mile basis;

C. Identification of each project by address and county for each pipeline replacement project completed in the Historic Test Year.

Response:

A) The Company does not have readily available full cost details broken down by cost component for all pipeline replacements. Please refer to Attachment A which shows the cost per mile for Columbia's replacement projects for the calendar years from 2009 through 2012, broken down by cost element, derived from CWIP data. The unit cost data for calendar year 2013 is not yet available.

B) Please refer to Attachment A which includes the job order data that was used to determine the total cost per mile for replacement projects.

C) Attachment B identifies the address or description, county and city for each replacement project completed during the Historic Test Year.

	CPA				CPA %				CPA Main Replacement Unit Cost			
	2009	**2010**	**2011**	**2012**	2009	2010	2011	2012	2009	2010	2011	2012
Contractor	$ 8,569,265	$ 14,624,422	$ 30,401,076	$ 39,588,902	37%	45%	46%	52%	$ 175,510	$ 228,230	$ 289,519	$ 371,768
Const Overheads	$ 3,573,532	$ 4,833,182	$ 9,900,990	$ 8,382,031	15%	15%	15%	11%	$ 73,191	$ 75,427	$ 94,290	$ 78,713
Material	$ 1,479,273	$ 2,436,129	$ 4,277,422	$ 5,188,879	6%	8%	7%	7%	$ 30,298	$ 38,018	$ 40,735	$ 48,727
Paving	$ 4,868,221	$ 4,595,953	$ 12,801,764	$ 14,007,638	21%	14%	20%	18%	$ 99,708	$ 71,725	$ 121,915	$ 131,542
Labor	$ 2,025,897	$ 2,196,800	$ 3,246,176	$ 3,358,537	9%	7%	5%	4%	$ 41,493	$ 34,283	$ 30,914	$ 31,539
Vehicles	$ 476,703	$ 543,953	$ 907,516	$ 1,081,997	2%	2%	1%	1%	$ 9,764	$ 8,489	$ 8,643	$ 10,161
Other	$ 2,455,735	$ 2,912,130	$ 3,983,452	$ 4,675,725	10%	9%	6%	6%	$ 50,297	$ 45,447	$ 37,936	$ 43,908
Total Cost	$ 23,448,625	$ 32,142,568	$ 65,518,396	$ 76,283,710	100%	100%	100%	100%	$ 480,260	$ 501,620	$ 623,953	$ 716,358

	Miles				
	2009	2010	2011	2012	Grand Total
CPA	49	64	105	106	324

$/mile by year	
2009	$ 480,260
2010	$ 501,620
2011	$ 623,953
2012	$ 716,358

I&E Exhibit No. 4
Schedule 12

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement -- Set GS

Question No. I&E-GS-009:

What is the current number of leaks on bare steel, cast iron, and wrought iron broken down by pipe type system wide?

Response:

Data by pipe type is not currently available to respond to request I&E-GS-009. Due to reporting limitations, pipe material is documented at the time of the repair/replacement.

Below is the current total number of open leaks by mains, services, and station piping/meter setting.

Probable Leak Source	**Type 1**	**Type 2**	**Type 3**	**Total # of Leaks**
Mains	1	1192	5589	6782
Services	1	410	1328	1739
Station Piping/Meter Setting	2	1	4	7
Total	4	1603	6921	8528

2014 Leaks Cleared by Type/Material

	Bare Steel	Cast Iron	Wrought Iron	Total
Main	2463	90	28	2581
Service	746	2	0	748
Station Piping/Meter Setting	140	0	0	140
Total	3349	92	28	3469

Question No. I&E-GS-006
Respondent: M. Davidson

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-006:

Reference Columbia Statement No. 15, Page 12, Lines 11-13. Regarding the cost per foot of pipe replacement, provide a schedule for each of the years from 2008 to 2013 showing the cost and the percentages that of the total that is attributable to pipe, material, labor, and restoration.

Response:

See Attachment A. The cost per year by component can vary by the location of projects and type of pipe being replaced.

I and E [illegible]
Attachment A
Page 1 of 1

CPA

	2008	2009	2010	2011	2012	2013
Contractor	$ 18,618,963	$ 8,569,265	$ 14,424,922	$ 30,401,076	$ 39,580,902	$ 42,329,611
Const Overheads	$ 4,473,968	$ 3,573,532	$ 4,833,192	$ 9,900,590	$ 8,382,031	$ 8,760,891
Material	$ 3,538,907	$ 1,479,273	$ 7,406,129	$ 4,277,422	$ 5,108,879	$ 5,792,778
Paving	$ 6,840,110	$ 4,868,227	$ 4,585,953	$ 12,801,764	$ 14,007,630	$ 20,015,407
Labor	$ 2,041,360	$ 2,023,097	$ 7,196,000	$ 3,246,176	$ 3,358,537	$ 4,249,161
Vehicles	$ 705,744	$ 476,703	$ 543,950	$ 907,516	$ 1,001,997	$ 1,323,277
Other	$ 3,221,475	$ 2,456,735	$ 2,512,130	$ 3,983,452	$ 4,675,725	$ 5,624,377
Total Cost	$ [illegible]	$ 23,446,625	$ [illegible]	$ 63,513,595	$ 75,283,710	$ 88,095,502

CPA %

	2008	2009	2010	2011	2012	2013
Contractor	40%	37%	45%	46%	52%	48%
Const Overheads	11%	15%	15%	15%	11%	10%
Material	9%	6%	8%	7%	7%	7%
Paving	17%	21%	14%	20%	19%	23%
Labor	7%	9%	7%	5%	4%	5%
Vehicles	2%	2%	2%	1%	1%	2%
Other	8%	10%	9%	6%	6%	6%
Total Cost	100%	100%	100%	100%	100%	100%

$/foot by year	
2008	$ 81.25
2009	$ 90.96
2010	$ 95.00
2011	$ 110.17
2012	$ 135.67
2013	$ 131.82

CPA Main Replacement Unit Cost

	2008	2009	2010	2011	2012	2013
Contractor	$ 37.77	$ 33.24	$ 43.23	$ 54.83	$ 70.41	$ 72.85
Const Overheads	$ 8.96	$ 13.16	$ 14.29	$ 17.86	$ 14.91	$ 15.05
Material	$ 7.09	$ 5.74	$ 25.20	$ 7.72	$ 9.23	$ 9.97
Paving	$ 13.73	$ 18.28	$ 13.58	$ 23.09	$ 24.95	$ 34.49
Labor	$ 5.09	$ 7.86	$ 6.49	$ 5.85	$ 6.57	$ 7.31
Vehicles	$ 1.57	$ 1.85	$ 1.61	$ 1.64	$ 1.92	$ 2.20
Other	$ 6.65	$ 9.53	$ 5.61	$ 7.18	$ 8.32	$ 9.84
Total Cost	$ 81.25	$ 90.95	$ 95.00	$ 110.17	$ 135.67	$ 131.82

VERIFICATION

RE: PUC v. Columbia Gas of PA - Docket No. R-2015-2468056

I, __David D. Kline______, hereby state that the facts set forth in the foregoing document, ___I&E Statement No. 4 Revised and I&E Exhibit No. 4 Revised__, are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at any hearing. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. §4904 relating to unsworn falsification to authorities).

8/4/2015
Date

Name

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	R-2015-2468056
Columbia Gas of Pennsylvania, Inc. Base Rate Case	:	
	:	

BUREAU OF INVESTIGATION AND ENFORCEMENT
ERRATTA TO THE DIRECT TESTIMONY OF
CHRISTOPHER KELLER

The Bureau of Investigation and Enforcement ("I&E") respectfully submits the following errata to the Direct Testimony of Christopher Keller, I&E Statement No. 2 in the above captioned proceeding.

Reference	**Reads:**	**Should Read:**
Page 16, Line 12	… revenue requirement for the Company is $566,822,257.	… revenue requirement of the Company is $567,378,872.
Page 16, Line 13	… represents an increase of $11,192,977 …	… represents an increase of $11,749,592 …
Page 17, Table 1, Line: Operating Revenue, Column: Proposed	$566,822,257	$567,378,872

Reference	Reads:	Should Read:
Page 17, Table 1, Line: Operating Revenue, Column: Allowances	$11,192,977	$11,749,592

For convenience, I&E has attached the relevant pages with this correction, which will be substituted in the copies of the testimony submitted for the record.

A. For the HTY, I referred to the Company's Exhibit No. 4, Schedule 2, page 11, which provided the cost incurred for injuries for the twelve months ended November 30, 2012, November 30, 2013, and November 30, 2014 which I used to calculate a three-year historic average of $321,805 [($261,045 + $368,598 + $335,772) ÷ 3]. I then applied the inflation factor of 1.8385% to the HTY amount to calculate a FTY amount of $327,721 ($321,805 X 1.8385%). Finally, I applied the inflation factor of 1.8623% to the FTY amount to determine a FPFTY amount of $333,825 ($327,721 X 1.8623%) (I&E Ex. No. 2, Sch. 10).

SUMMARY OF I&E OVERALL POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $567,378,872. This recommended revenue requirement represents an increase of $11,749,592 to the I&E adjusted present rate revenues of $555,629,280. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimonies of I&E Witnesses Maurer (I&E St. No. 1) and Hubert (I&E St. No. 3).

A calculation of the I&E-recommended revenue requirement is shown below:

Columbia Gas of PA Inc		TABLE I			
R-2015-2468056		INCOME	SUMMARY		
6/24/15					
	12/31/16	INVESTIGATION & ENFORCEMENT			
	Proforma	[			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	534,899,150	20,730,130	555,629,280	11,749,592	567,378,872
Deductions:					
O&M Expenses	367,779,576	7,439,130	375,218,706	153,445	375,372,151
Depreciation	54,751,328	0	54,751,328		54,751,328
Taxes, Other	3,221,085	-132,523	3,088,562	0	3,088,562
Income Taxes:					
Current State	1,186,921	1,060,438	2,247,359	862,753	3,110,112
Current Federal	28,054,757	4,617,465	32,672,222	3,756,688	36,428,910
Deferred Taxes	-51,103	0	-51,103		-51,103
ITC	-360,240	0	-360,240		-360,240
Total Deductions	454,582,324	12,984,510	467,566,834	4,772,886	472,339,720
Income Available	80,316,826	7,745,620	88,062,446	6,976,706	95,039,152
Measure of Value	1,325,130,928	-1,465,855	1,323,665,073	0	1,323,665,073
Rate of Return	6.06%		6.65%		7.18%

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

WHEREFORE, the Bureau of Investigation & Enforcement respectfully requests that Administrative Law Judge Mary D. Long, the Commission, and the parties to this proceeding note the above errata to the Direct Testimony of Christopher Keller, I&E Statement No. 2.

Respectfully Submitted,

Scott B. Granger
Prosecutor
PA Attorney I.D. # 63641

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Dated: July 1, 2015