COLUMBIA STATEMENT NO. 108-R

COLUMBIA GAS OF PENNSYLVANIA, INC.

Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

and

Fair Rate of Return

July 16, 2015

<u>Columbia Gas of Pennsylvania, Inc.</u>
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INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q. Mr. Moul, have you previously submitted direct testimony in this proceeding?

A. Yes. My direct testimony was submitted with the Company's case-in-chief on March 19, 2015 and was pre-marked as Columbia Statement No. 8.

Q. What is the purpose of your rebuttal testimony?

A. Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") has requested that I review and respond to the rate of return testimony presented by Mr. Aaron L. Rothschild, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), and Ms. Rachel Maurer, a witness appearing on behalf of the Bureau Of Investigation and Enforcement ("I&E").

Q. Have you prepared an exhibit to accompany your rebuttal testimony?

A. Yes. I have prepared Exhibit PRM-2R, which is divided into seven (7) schedules, to accompany my rebuttal testimony.

Q. Please identify the principal areas of controversy concerning the rate of return issue in this proceeding.

A. The appropriate return on common equity for the Company represents the major rate of return issue disputed in this case. Additional rate of return items that have been disputed by the opposing parties include the Company's proposed capital structure that Mr. Rothschild has challenged and the cost of short-term debt that

Ms. Maurer has challenged. As I will demonstrate below, Mr. Rothschild's alternative hypothetical capital structure must be rejected and Ms. Maurer's cost of short-term debt is not appropriate for the Company.

Q. Please summarize your views regarding the opposing parties' equity cost rate proposals.

A. Ms. Maurer contends that CPA's equity return rate should be set at 9.24% and Mr. Rothschild asserts that an 8.88% equity allowance is sufficient. In my opinion, the opposing parties' proposals are substantially below CPA's cost of equity and, if adopted, would be of serious concern to the financial community.

Q. What explains the substantial disparity between their recommendations and your proposed 10.95% equity allowance?

A. The differences between our cost of equity proposals are attributable to a number of factors, including: (i) the selection of proxy group companies to measure the cost of equity, (ii) the determination of a reasonable Discounted Cash Flow (DCF) growth rate, (iii) whether a leverage adjustment to the DCF is necessary, (iv) the extent to which other methods of determining the cost of equity provide a reasonable measure of the appropriate cost of common equity, and (v) whether the Commission should acknowledge the exemplary performance of the Company's management in setting the rate of return on common equity.

Q. How do the cost of equity proposals by Mr. Rothschild and Ms. Maurer compare to the utility returns recently authorized nationally?

A. Technical disputes about methodology and data aside, the proposed costs of equity proposed by Mr. Rothschild and Ms. Maurer are simply not representative of the returns investors can earn on other investments of comparable risk, including investments in other natural gas utilities like CPA. In this regard, it is worthwhile to establish a benchmark that compares the competing returns in this case. Regulatory Research Association ("RRA"), a service provided by SNL Financial, contains these data. The RRA report provides authorized rates of return nationally and is publicly available by subscription. According to RRA, the average electric utility authorized return in the first quarter of 2015 was 10.37%, as compared to 9.91% for the calendar year 2014[1]. For natural gas utilities, the first quarter of 2015 authorized return was 9.47%, as revealed from a range of returns from 9.05% to 10.30%, as compared to 9.78% for the calendar year 2014. The range for 2014 was from 9.10% to 10.80%. I should note that the first quarter average for the gas utilities was taken from a small sample of just three decisions. With the recent increase in public utility bond yields that I describe below, there is reason to expect that in the future the authorized returns will increase with the forecast increase in those yields.

The rates of return on common equity of 8.88% proposed by Mr. Rothschild and 9.24% proposed by Ms. Maurer are seriously deficient and will not provide CPA with the opportunity to earn its investor perceived cost of capital for the fully forecast test year of 2016.

Q. Is there reason to believe that we have now passed the trough in authorized returns given the uptick in long-term interest rates?

A. Yes. While the decline in the cost of capital is well documented for the past several years, the recent rise in long-term interest rates reveals that this trend will reverse

[1] Excluding the 200 basis point premium allowed in Virginia for generating assets, the electric returns were 9.67% and 9.76%, respectively.

in the near-term future. I should note that capital costs, as measured by the yields on Baa-rated public utility bonds, have risen from 5.09% in January 2014 to 5.13% in June 2015 (an increase of 0.04%). This increase in capital costs refutes Mr. Rothschild's claim that the Columbia Water Company order by the Commission entered on January 23, 2014 somehow substantiates an extraordinarily low return. Moreover, when the Commission set the return on equity for Columbia Water Company at 9.75%, it did so in the context of a 64.4% common equity ratio that reflects less financial risk than CPA's common equity ratio of 52.21%. For example, the yield on Baa-rated public utility bonds bottomed out at 4.39% in January 2015, and moved up to 5.13% in June 2015, an increase of 0.74%. Likewise, the yield on 30-year Treasury bonds has moved up by 0.65% (3.11% - 2.46%) from January to June 2015. Also, the yield on 10-year Treasury notes has moved up by 0.48% (2.36% - 1.88%) in 2015. As I noted in my direct testimony, equity risk premiums decline as interest rates increase, and vice-versa. I have already factored higher interest rates into my analysis when I performed my Risk Premium model. It is important to emphasize that the cost of equity is what investors expect for the future. Clearly, rising interest rates signal an increase in the cost of capital and an increase in authorized ROEs.

Q. Mr. Rothschild also reviews the level of the VIX and concludes from it that stock market volatility is low, which justifies a low equity return for the Company in this case. Please respond.

A. I agree that the VIX is a valid measure of expected stock market volatility and one which I follow routinely. The trading pattern of the VIX is typically inverse to the level of stock prices. That is to say, the VIX increases when stock prices are falling and the VIX declines when stock prices rise. Recently, there has been an uptick in the VIX to the 17 to 19 range as a reflection of higher risk for stocks generally. So while the VIX may have been in the 13-14 range when Mr. Rothschild prepared his testimony, the VIX has increased since then as the risk of stocks has increased.

CAPITAL STRUCTURE

Q. How does the Company's capital structure proposal differ from that advocated by Mr. Rothschild?

A. The Company has proposed its actual capital structure for the fully forecast test year. Ms. Maurer has accepted the Company's proposed capital structure ratios because they conform with Commission policy for establishing the capital structure ratios for ratesetting purposes. The Commission only employs a hypothetical capital structure when the utility's actual capital structure is atypical, which is not the case for CPA. It is not appropriate to use hypothetical capital structure ratios as long as the actual capital structure ratios of the Company are within the range of ratios employed by an appropriate barometer group. This is the criteria that the Commission has adopted to determine whether the utility's actual capital structure or a hypothetical should be used (see pages 59-69 of Final Order entered December 28, 2012 in PPL Electric's base rate proceeding at Docket No. R-2012-2290597). In this case for CPA, the Company's actual capital structure fulfills the requirement of falling within the range of ratios of the barometer group, as I established in my direct testimony, (see page 8 through 12 of Statement 8) and further confirmed by Ms. Maurer (see pages 9 and 10 of I&E Statement No. 1).

Q. But Mr. Rothschild claims that your comparison of the Company's capital structure to the barometer group is invalid because you looked at only permanent capital and excluded short-term debt. Please respond.

A. Making the comparison of capital structure ratios excluding short-term debt is the only valid method for comparison to confirm the reasonableness of the ratios pursuant to the Commission's policy on this matter. That is to say, I have analyzed the Company's and barometer group's capital structures on an apples to apples basis. My consistent approach is contrasted to Mr. Rothschild who has taken an apples to oranges comparison for capital structure. I say this because he is looking at the Company's short-term debt ratio calculated from the average balances over a twelve-month period and compared it to short-term debt ratios for the barometer group (i.e., Gas Group) using end of period amounts. This is an entirely invalid basis for analyzing short-term debt ratios because short-term debt for natural gas utilities fluctuates on a seasonal basis that is linked to the inventory of natural gas held in storage. That is to say, short-term debt runs in a cycle where it increases from late spring through late fall as the level of stored gas inventory builds and then declines during the heating season as the inventory of stored gas is drawn-down and sold to customers. The Commission has acknowledged this pattern associated with short-term debt borrowings that are linked to natural gas held in storage (see pages 49-51 of the Final Order entered February 8, 2007 in PPL Gas Utility's base rate proceeding at Docket No. R-00061398) ("PPL Gas"). Hence, the comparison used by Mr. Rothschild is invalid when considering a hypothetical capital structure.

Q. Does Mr. Rothschild's error in using a point time level of short term debt distort his hypothetical capital structure?

A. Yes. By using 10% short term debt in his hypothetical capital structure, Mr. Rothschild effectively increases Columbia's 5% average level of short term debt in the capital structure to 10% and reduces the equity balance by an equal amount. Accordingly, Mr. Rothschild's hypothetical includes a higher level of short term debt in the capital structure contrary to the Commission's PPL Gas decision. Indeed, the Company's proposed capital structure that contains 5.14% short-term debt is close to the 5.83% short-term debt ratio that the Commission accepted in the PPL Gas decision. Mr. Rothschild's 10.69% hypothetical short-term debt ratio is well off the mark in this regard.

Q. Should the ALJ and Commission adopt the Company's proposed capital structure ratios?

A. Yes. The Company's actual capital structure ratios are entirely reasonable and acceptable. Hence, hypothetical capital structure ratios should be rejected. The reasonableness of the Company's actual capital structure containing a common equity ratio of 52.21% is revealed by the data provided by Ms. Maurer. Her data shows that the Company's common equity ratio is within the range employed by her barometer group and therefore, supports the level of common equity proposed by the Company. For example, the five-year average common equity ratios shown by Ms. Maurer on her Schedule 2 of I&E Exhibit No. 1 are 46% to 54%. Focusing on the 2014 capital structures for the barometer group, the range of common equity ratios is 41.37% to 53.78%.

Q. What capital structure ratios do investors expect for the companies that comprise the barometer group that you used?

A. The Value Line reports for these companies reveal the following common equity ratios:

Company	2015	2016	2018-20
AGL Resources, Inc.	52.0%	51.5%	50.0%
Atmos Energy Corp.	55.5%	55.0%	55.0%
Laclede Group	46.0%	47.0%	49.0%
New Jersey Resources Corp.	67.5%	69.0%	72.5%
Northwest Natural Gas Co.	55.5%	55.5%	56.0%
Piedmont Natural Gas Co.	52.0%	54.0%	56.5%
South Jersey Industries, Inc.	53.0%	53.5%	53.0%
Southwest Gas Corporation	51.0%	51.0%	52.5%
WGL Holdings, Inc.	66.0%	67.0%	70.0%
Average	55.4%	55.9%	57.2%

Source: The Value Line Investment Survey, June 5, 2015

These Value Line data also reveal a trend toward higher common equity ratios for the future. As noted in my direct testimony (see page 20 of Statement No. 8), the Company's actual common equity ratio is 55.0% computed without short-term debt, which falls squarely within the common equity ratio shown above for the Gas Group. It is clear that the common equity ratio proposed by the Company is reasonable because it falls within the range of common equity ratios that comparable companies employ and investors expect.

Q. Mr. Rothschild also utilizes a hypothetical long-term debt ratio of 42.5% matches it with the Company's actual 5.31% cost of long-term debt that is actually outstanding. Is this proposal reasonable?

A. No. This is an improper and inconsistent approach. The actual cost of long-term debt can only properly be assigned to the actual long-term debt ratio.

Q. Mr. Rothschild also compares the capital structure of CPA to its parent company, NiSource Inc. Is his comparison valid?

A. No. First, under Commission precedents, the Commission does not look outside the capital structure of the operating utility unless it is shown to be abnormal as measured being outside of the range of ratios employed by the various barometer group companies. As I have illustrated, Columbia's capital structure ratios are well within the range employed by the barometer group companies both historically and on a projected basis. Second, the capital structures of utility parents or holding companies can and are affected by financing many things other than utility rate bases. For example, the capital structure of NiSource includes the merger debt that was associated with the 2000 acquisition of Columbia Energy Group by NIPSCO Industries, the former name of NiSource. It is especially important to note that the presence of the merger-related debt invalidates Mr. Rothschild's comparison. The reason that the comparison is invalid is due to the fact that merger-related debt does not finance rate base.

COST OF SHORT-TERM DEBT

Q. In her direct testimony, Ms. Maurer submitted an alternative and lower cost of short-term debt. Is her proposal reasonable?

A. No. Her lower proposed cost of short-term debt for CPA is the product of a lower assumed cost of pool borrowing by CPA. The principle problem that I have with Ms. Maurer's proposal is her use of backward looking historical interest spreads over LIBOR rates to determine the margin to be applied to the LIBOR forecasts.

Rates in this proceeding will become effective on January 1, 2016, and the fully forecast test period covers the twelve months ending December 31, 2016. So a backward look at the spreads is not relevant for this case.

Q. What other problems exist when looking at historical spreads as Ms. Maurer has done?

A. Analyzing historical spreads between short-term debt interest rates are not valid because the historical rates achieved were related to commercial paper borrowing by NiSource Finance Corporation. There is, of course, no assurance that NiSource Finance will always have access to the commercial paper market in the future. As such, they play no role in the pricing of loans pursuant to the Revolving Credit Agreement dated December 5, 2014 between NiSource Finance Corporation and Barclays Bank acting as agent for a consortium of five banks supporting a $2 billion line of credit. The pricing grid for this loan is provided in Schedule 1 of Exhibit PRM-2R and indicates the spread that will be in effect for the fully forecast test year is 1.075%. This spread is lower than the one I used in my direct testimony due to the upgrade of the credit rating to BBB+ by Standard & Poor's on June 18, 2015. A forecast of LIBOR rates should be considered based upon the July 1, 2015 in Blue Chip. The latest Blue Chip shows that the forecast average LIBOR for the four quarters of 2016, i.e., the fully forecast test period in this case, is 1.50% (1.0% + 1.3% + 1.7% + 2.0% = 6.0% ÷ 4). To this base interest rate must be added the 1.075% margin or spread that will be in effect contractually for the fully forecast test period. With that spread, the cost of short-term debt will be 2.575% (1.50% + 1.075%) using the latest LIBOR forecast rates. This short-term debt borrowing rate is only slightly less than the 2.86% rate that was used in the Company's original filing. The slightly lower short-term debt cost rate results in an 8.12% (2.575% x 0.0514 = 0.13% + 2.27% + 5.72%) overall rate return, or just a two basis points (0.02%) reduction in the Company's filed return.

COMPARABLE COMPANIES

Q. Are there differences in the barometer groups utilized by the rate of return witnesses in this case?

A. Yes, but they are not major, except for an error made by Mr. Rothschild.

Q. Ms. Maurer used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble her barometer groups. Please explain why this is not the correct criterion.

A. For natural gas companies, the percentage of regulated revenues cannot be used to select a barometer group because the margins on other business segments in their groups are generally dissimilar to the gas distribution business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the large revenues and small margins associated with that business. That is to say, energy trading generates large amount of revenues, but little profits because the margins on such trades are very small. The correct screening criterion is the percentage of gas income to total income and related percentage of gas assets to total assets. These measures best describe how significant the return achieved on regulatory assets is to the total business and the amount of capital that a firm devotes to each business segment.

The data provided in Schedule 2 of Exhibit PRM-2R shows that all of the companies that comprise my barometer group are properly included in the barometer group. The focus on revenues by Ms. Maurer is entirely inappropriate.

Ms. Maurer's reasoning for excluding New Jersey Resources from the barometer group is based on her mistaken belief that their relatively low percentage of revenues from gas utility operations disqualifies it from their proxy groups. But the revenue percentage is the wrong criteria for assessing the eligibility of a company for membership in the proxy group as explained above. As shown on Schedule 2 of Exhibit PRM-2R, the percentage of regulated earnings for New Jersey Resources is 64.96% and the percentage of regulated assets for New Jersey Resources is 69.72%. With New Jersey Resources in the barometer group, the average regulated income is 92.97% for my Gas Group and the average regulated assets are 85.44% for the Gas Group. This shows that my Gas Group is predominately comprised of regulated utilities.

Q. Mr. Rothschild indicates that he has used your Gas Group to measure the cost of equity in this case. Have you detected any problem with his choice?

A. Yes. Instead of using New Jersey Resources, Mr. Rothschild erroneously included NRG Energy in his group. I believe that he made a mistake by inputting the ticker symbol NRG instead of NJR.

Q. How does this affect the result?

A. It is not possible to determine precisely how this error affects the outcome of Mr. Rothschild's testimony. This is because he has not provided the data inputs necessary to make the substitution of New Jersey Resources for NRG Energy. But what can be said is that if we remove NRG Energy from his DCF calculation, his DCF results become 8.71% and 8.69%, rather than the 8.87% and 8.90% that he shows on Schedule ALR-4. These results are even further out of line from what would be a reasonable rate of return, and further demonstrate that Mr. Rothschild's DCF methodology is flawed and should be rejected, as I explain later.

DISCOUNTED CASH FLOW

Q. The DCF model has been used by all rate of return witnesses to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given considerable weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.). For that reason, I disagree with Ms. Maurer's approach, which appears to rely almost exclusively on the DCF method, and likewise with Mr. Rothschild's analysis that gives his DCF results exclusive weighting.

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Ms. Maurer, Mr. Rothschild, and me. Mr. Rothschild also offers a complex two-stage DCF model, which is not appropriate in the case, and has never been used by the Commission in a rate case decision. I will discuss in detail a correction of his two-stage DCF model on page 23 of my rebuttal testimony.

Q. Do the DCF results proposed by Ms. Maurer provide a reasonable representation of the cost of equity?

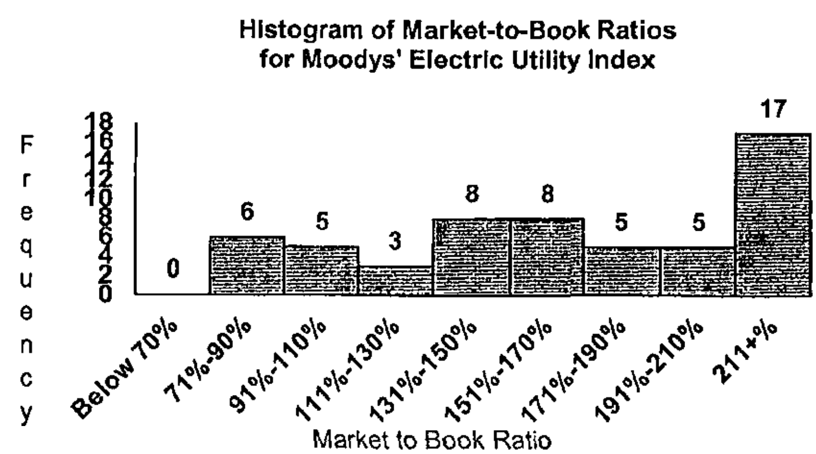
A. Not in my opinion. The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the barometer group results are unreasonable on their face, the reliability of the method being used, or the witness' application of that method, must be questioned. As indicated below, several of Ms. Maurer's DCF results fall into that category:

Company		Average: 52 wk & Spot Yield	+	Growth	=	Total
Northwest Natural Gas		4.02%	+	4.38%	=	8.40%
Southwest Gas		3.06%	+	4.48%	=	7.54%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. Yet, each of the companies listed above have DCF returns calculated by Ms. Maurer that fail to provide a sufficient spread over the six-month average yield of 4.65% on Baa-rated public utility bonds, or the June 2015 yield that was 5.13%. By eliminating the anomalous results for the two companies shown above, the average DCF result would be 9.67% (3.69% + 5.98%). Adding the leverage adjustment that I developed in my direct testimony to that return would produce a final DCF result of 10.39% (9.67% + 0.72%). This return does not reflect the adjustment to reflect the lower credit quality of CPA compared to the barometer group.

Q. One of the key features of Mr. Rothschild's direct testimony is his contention that when stock prices are considerably higher than their book value then the return that investors expect to receive on their market prices is considerably less than whatever is anticipated on book value. Please respond.

A. Mr. Rothschild makes this assertion repeatedly throughout his direct testimony. For example, he states that when a company has a market-to-book ratio above 1, it is over earning. But such a claim is totally unwarranted. The Commission has stated that it does not believe that its rate case decisions can ensure any particular market-to-book ratios (PUC vs. The York Water Co., 62 Pa.PUC 459, Order Entered November 25, 1986). Moreover, if his assertion were correct then it leads to the inevitable conclusion that if investors expected to earn their required return, then stock prices would revert to their book value. However, the market for stocks shows that Mr. Rothschild's assertion is baseless. In the long history of market-to-book ratios for gas utilities since 1958, M/B ratios equal to 1.0 are unusual and ratios of greater than 1.0 are quite common. That data is shown below.



These data show that it is unusual for market prices to gravitate to book value. Indeed, in only about 9% of the years studied did gas utility stock prices approximate book value. In 81% of the years, gas utilities stock prices exceeded book value and sometimes by a substantial amount. The average market-to-book ratio over the past 57 years is 174%.

DCF DIVIDEND YIELD

Q. Ms. Maurer challenges the ex-dividend adjustment that you made in calculating representative dividend yields. Please comment.

A. First, and contrary to Ms. Maurer's belief, there has been extensive academic research on the impact of the ex-dividend date on stock prices. In fact, I am aware of numerous academic studies that indicate that stock prices react to the ex-dividend date[2]. Second, Ms. Maurer claims that there is no evidence to suggest that investors make this adjustment. This assertion again is incorrect because the

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[2]Avner Kalay, "The Ex-Dividend Day Behavior of Stock Prices: A Re-examination of the Clientele Effect," Journal of Finance, 37 (September 1982), 1059-70; Keneth M. Eades, Patrick J. Hess, and E. Han Kim, "On Interpreting Security Returns During the Ex-Dividend Period," Journal of Financial Economics, 13 (March 1984), 3-34; Patrick J. Hess, "The Ex-Dividend Day Behavior of Stock Returns: Further Evidence on Tax Effects," Journal of Finance, 37 (May 1982), 445-56: James M. Poterba and Lawrence H. Summers, "New Evidence That Taxes Affect the Valuation of Dividends." Journal of Finance, 39 (December 1984), 1397-1416; Michael Barclay, "Tax Effects with No Taxes? Further Evidence on the Ex-Dividend Day Behavior of Common Stock Prices," working paper, Stanford University (September 1984); and Costas P. Kaplanis, "Options, Taxes, and Ex-Dividend Day Behavior," Journal of Finance, 41 (June 1986), 411-24.

See Kalay, "The Ex-Dividend Day Behavior of Stock Prices"; Jerry Green, "Taxation and the Ex-Dividend Day Behavior of Common Stock Prices" working paper. National Bureau of Economic Research,Cambridge, Mass (1980); and Hess, "The Ex-Dividend Day Behavior of Stock Returns." Black and Scholes, "The Effects of Dividend Yield and Dividend Policy on Common Stock Prices and Returns."

Miller and Scholes, "Dividends and Taxes." See Marshall Blume, "Stock Returns and Dividend Yields: Some More Evidence." Review of Economics and Statistics, 62 (November 1980), 567-77.

Edwin J. Elton and Martin J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," Review of Economics and Statistics, 52 (February 1970), 68-74.

Securities and Exchange Commission ("SEC") has alerted investors to the significance of the ex-dividend adjustment, stating:

> "With a significant dividend, the price of a stock may move up by the dollar amount of the dividend as the ex-dividend date approaches and then fall by that amount after the ex-dividend date. A stock that has gone ex-dividend is marked with an "x" in newspapers on that day."
> http://www.sec.gov/answers/dividen.htm

Third, Ms. Maurer claims that she is unaware of any financial publications that provide ex-dividend adjusted yields. However, the ex-dividend dates are routinely reported in the financial press and are widely available on the internet. Moreover, the Barron's source that Ms. Maurer has used for her stock prices, as well as The Wall Street Journal, both provides a list of stocks that trade ex-dividend. In fact, while there is a change in the price of stock equal to the amount of the dividend payment when the stock trades without its dividend on the ex-dividend date, there is no net change from the prior day's stock price shown in the daily change column. The Wall Street Journal signifies the lack of pricing change related to the dividend by the "x" notation in its stock listings. In short, I am confident that investors are well aware of when stocks trade ex-dividend and take that into account in their decisions to buy or sell.

Q. What is the ex-dividend adjustment in this case?

A. The ex-dividend adjustment added just one basis point (i.e., 0.01%) to my 12-month average, 6-month average, and 3-month average dividend yields.

DCF GROWTH RATE

Q. As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A. The theory of the DCF holds that (1) the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share with a constant P-E ratio and (2) dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model are forecasts of earnings per share growth.[3]

Q. Please summarize the DCF growth rate analysis performed by Ms. Maurer.

A. As shown on page 3 of Schedule 8 of I&E Exhibit No. 1, Ms. Maurer proposes a growth rate of 5.59%, based on her review of analysts' projected earnings growth rates. I generally concur with Ms. Maurer's approach and would only note that if

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3 "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

she had excluded the abnormally low growth rates of 4.38% for Northwest Natural Gas and 4.48% for Southwest Gas, her average growth rate would have been 5.98%.

Q. On page 27 of her testimony, Ms. Maurer cautions that the analysts' forecasts of earnings per share growth used in her DCF analysis may be biased. Please comment.

A. As a preliminary matter, I disagree with Ms. Maurer's premise and would point to an article published in The Wall Street Journal on April 26, 2010, provided on Schedule 3 of Exhibit PRM-2R, which reported that 64% of companies had beaten analysts' forecasts since the start of 1999. More importantly, however, investors rely heavily on analysts' forecasts in determining the price they are willing to pay for a particular stock. Consequently, if the forecasted earnings growth rates were to be discounted, a downward adjustment would also have to be made to the stock prices those forecasts have produced. This, in turn, would generate higher dividend yields in the DCF analysis.

Q. In discussing her decision not to use a log-linear analysis as part of the growth rate component of the DCF, Ms. Maurer acknowledged that replacement of worn-out infrastructure will produce bigger increases in earnings growth prospectively than historically. Does her growth rate adequately reflect her observation about a significant increase in capital spending for gas utilities generally and CPA in particular?

A. No. I do not see one. She merely adopts the analysts forecast earnings growth rates without first investigating whether those growth rates are responsive to the purported increase in earnings attributed to higher infrastructure investment.

One way to assess the increase in earnings, that may develop in the future, is to look at the level of forecast construction expenditure in relation to existing utility plant in service ("UPIS") net of accumulated depreciation. Schedule 4 of Exhibit PRM-2R provides these data. We can see that the average annual level of construction expenditure of 17.04% for CPA exceeds the average percentage of 11.77% for the Gas Group, and indeed exceeds all members of the Gas Group. The bottom line is that the barometer group's average growth rate employed by Ms. Maurer provides an understatement of the growth rate and in particular for CPA

Q. In his direct testimony, Mr. Rothschild relies principally on retention growth in his DCF model. Please discuss the limitations of this approach.

A. Retention growth, along with external financing growth, is another means of describing book value per share growth. Other factors also contribute to earnings growth that is not accounted for by the retention growth formula, such as sales of new common stock that Mr. Rothschild has included in his analysis, reacquisition of common stock previously issued, changes in financial leverage, acquisition of new business opportunities, profitable liquidation of assets, and repositioning of existing assets. In my view, book value per share growth, or its surrogate retention growth, does not represent the proper financial variable to be considered when selecting the DCF growth component. This is because utility stocks do not typically trade at a constant multiple of book value, which Mr. Rothschild has assumed in his two-stage DCF model.

Q. Please illustrate the infirmities in Mr. Rothschild's DCF approach.

A. Mr. Rothschild indicates that his preferred method for selecting the growth rate component of the DCF is the "b x r" approach, i.e., the retention growth method. This special form of the DCF, as described by Mr. Rothschild, merely adjusts his assumed return on book common equity by the difference between the dividend yield on book value and the dividend yield on market value. The table provided below shows how his DCF result (using year-end and average market prices) can be expressed from the values shown on page 1 of ALR Schedule 4:

	Year Ending 05/31/15	As of 05/31/15
Return on Equity (Line 2c)	10.50%	10.50%
Dividend Yield on Book Value (Line 2b)	-5.89%	-6.11%
Dividend Yield on Market Value (Lines 1 & 6)	3.56%	3.90%
Result	8.17%	8.29%
New financing growth (Line 4)	0.70%	0.61%
Average DCF return	8.87%	8.90%

A key component of retention growth is his assumed return on book common equity. In his testimony, Mr. Rothschild acknowledges that his Gas Group is projected to earn a 10.50% return on equity, but instead he proposes a DCF return of just 8.87% or 8.90%. As shown above, the approach taken by Mr. Rothschild is quite alien to the traditional form of the DCF model that is familiar to the Commission. It is also based on Mr. Rothschild's incorrect view that market to book ratios in excess of 1.0 mean that companies are earning in excess of the cost of capital.

Q. Are there other infirmities in the earnings retention growth formulation presented by Mr. Rothschild?

A. Yes. The inputs used by Mr. Rothschild do not conform with investor expectations as revealed by the Value Line data. However, the projected earned returns published by Value Line are understated because of their reliance on year-end book values, rather than average book values. An adjustment to the Value Line returns is necessary to convert the forecasts from year-end to average book values. This is because with an increasing book value driven by retention growth, the average book value will be less than the year-end book value. For that reason, the FERC adjusts the year-end returns to derive the average yearly return, using the formula 2 (1 + G) / (2 + G) (see 92 FERC ¶ 61,070). Generally speaking, this adjustment increases the earnings retention growth. I have used a variant of the FERC's adjustment procedure for the purpose of my analysis reported on Schedule 5 of Exhibit PRM-2R. Here, the use of the average book value in the calculation provides an 11.25% forecast return on average book common equity, rather than the 10.50% return on book value, which was used by Mr. Rothschild. I also show on Exhibit PRM-2R that the external, i.e., "New Financing," growth is 1.01% for the barometer group. This level of growth for New Financing is higher than the 0.61%/0.70% rate that Mr. Rothschild has used.

Q. What DCF results are suggested with the data that you provided on Schedule 5 of Exhibit PRM-2R?

A. I have recalculated those DCF results below. The growth rate that I have used in this calculation is 5.99% provided on Schedule 5 of Exhibit PRM-2R. I have also included the leverage adjustment, which I developed in my direct testimony. The resulting DCF return is:

	D_1/P_0	+	g	=	k	+	*lev.*	=	K
Gas Group	3.73%	+	5.99%	=	9.72%	+	0.72%	=	10.44%

The DCF return shown above is without the upward adjustment to recognize the higher credit quality risk of CPA. This DCF result is also unresponsive to the much lower common equity ratio Mr. Rothschild has proposed with his hypothetical capital structure.

Q. Mr. Rothschild submits an alternative calculation as his additional method to measure the cost of equity. Is this data useful in this case?

A. No. As a preliminary matter, his alternative DCF result of 8.95% cannot be given serious consideration because it provides inadequate compensation for the equity return that is too close to the cost of debt. Mr. Rothschild uses book value per share growth as a key input in his alternative form of the DCF, which makes this method invalid as an alternative measure of the cost of equity. Moreover, if we substitute the future "VL midpoint stock price forecast" that is shown on page 2 of Schedule ALR-4, the DCF return moves to 10.76% from Mr. Rothschild's number of 8.95%. The details of this calculation are shown on Schedule 6 of Exhibit PRM-

2R. And this 10.76% non-constant DCF return does not reflect the leverage adjustment nor credit quality adjustment developed in my direct testimony.

LEVERAGE ADJUSTMENT

Q. Please respond to Ms. Maurer's criticisms of your leverage adjustment.

A. Ms. Maurer offers five reasons for not making a leverage adjustment. As a preliminary matter, Ms. Maurer is incorrect to label the leverage adjustment as a "market-to-book" ratio adjustment because the market-to-book ratio plays no role in the leverage adjustment, and Ms. Maurer has not, nor could she, show that market-to-book ratios are part of the leverage adjustment. First, Ms. Maurer notes that the credit rating agencies assess financial risk in terms of the book value of debt in their analysis of the creditworthiness of a company. I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. They are judging risk associated with a company's debt. Hence, they are not concerned with the cost of equity or how it is applied in the ratesetting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of interest and principal by utilities. While Ms. Maurer's observation is correct, it has no relevance to my leverage adjustment.

Q. Ms. Maurer also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Initially, she cites to a Blue Mountain decision, which is now over 30 years old and, more importantly, was litigated in an environment that is distinguishable in a number of critical respects. For example, that case was not decided using the

DCF method. Rather, the Commission relied heavily on earnings/price ratios to set the return on equity in the context of a fair value rate base. Moreover, in its decision on remand, the Commission noted that over a period of years it was relatively easy to discern the trends in market-to-book ratios which, when compared to performance as measured by other financial ratios, can indicate the return levels the Commission must award to assure reasonable access by public utilities to the capital markets. Notably, the trends in market-to-book ratios during that period were substantially different from today. At the time that case was litigated, market-to-book ratios for the broader market generally approximated 1:1. That is to say, market prices in the late 1970s were about equal to book value. Since that time, share prices have moved much higher vis-à-vis their underlying book values. So, while the market-to-book ratio of the DJI approximated 1:1 in the late 1970s, today the DJI trades at 3.11:1 of book value. In short, the capital markets today are markedly different than those that existed at the time of the Blue Mountain case. I should also note that, since that time, the Commission has adopted my leverage adjustment to the DCF model on numerous occasions.

Ms. Maurer also points to several decisions where the Commission declined to make a leverage adjustment – i.e., rate cases including Metropolitan Edison, Aqua Pennsylvania, and the City of Lancaster Water Department. It is my understanding that the adjustment proposed in the MetEd case is distinguishable and, as such, the Commission's rejection of it in the MetEd case has no bearing on my adjustment here. Moreover, after rejecting an adjustment in the MetEd case, the Commission subsequently accepted my adjustment in a later case for PPL Gas

Utilities Corporation in Docket No. R-00061398. Further, the fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Ms. Maurer does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Just like an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case.

Q. Ms. Maurer next says that your leverage adjustment lacks academic literature support. Please respond.

A. Leverage adjustments are routinely discussed in the academic literature. Indeed, any basic finance textbook discusses the relationship between returns and the degree of financial leverage, and often references the work of Modigliani and Miller and Hamada. I have merely extended these well-accepted principles to the ratesetting process.

Q. Fourth, Ms. Maurer contends that your proposed leverage adjustment contains flaws related to the "ku" factor in the formula. Is she correct?

A. No. In fact, the Microsoft Excel spreadsheet that was attached to my response to interrogatory I&E-RR-005 essentially refuted the points raised in Ms. Maurer's testimony. As shown therein, the unlevered cost of equity (i.e., "ku") is solved in the equation by an iterative process that is no different than that used in standard financial formulas, such as the internal rate of return associated with the discounting of future cash flows (i.e., the foundation for the DCF model), statistical analysis for the slope of the regression equation, or the yield to maturity, which measures the effective cost rate of the Company's long-term debt. As such, Ms. Maurer's claims that there is no source for the 7.63% cost of equity for a firm with 100% equity is incorrect. The arithmetic is quite simple, 3.58% (D_1P_0) + 5.25% (g) – 1.19% (no debt) = 7.63%.

Q. Fifth, Ms. Maurer argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Ms. Maurer contends that information presented to investors, such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in her barometer group. This means that investors are well aware of the market capitalization of the natural gas utility stocks that Ms. Maurer relies upon for her analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. Since the financial risk associated with the book value capital structure is different from the market value of the capitalization, that risk difference must be taken into account. Hence, her point here is irrelevant.

Q. Mr. Rothschild criticized the leverage adjustment that you propose to account for the divergence of market capitalization and book value capitalization. Please comment.

A. It must be recognized that, in order to make the DCF results relevant in the ratesetting context, the market-derived cost rate cannot be used without modification. The importance of the leverage modification to the DCF results was fully supported in my direct testimony, wherein it was shown that the market value of the equity in the Gas Group's capitalization was much higher than its book value. The market value common equity ratio was 65.62% compared to a book value common equity ratio 54.30% (see page 1 of Schedule 10 of Exhibit 400). The leverage adjustment is necessary to make the market-derived DCF results applicable in the ratesetting context. Because the market based cost rate is determined based on less financial risk than that reflected in the ratemaking capital structure, and because increased financial risk justifies a higher return on equity, it is necessary to account for the higher financial risk that arises from the lower common equity ratio measured by book value capitalization.

Q. Do you agree with Mr. Rothschild's contention that the market value capital structure and the book value capital structure are two completely different ways of measuring the same thing?

A. No. As Professors Modigliani and Miller proved 50 years ago (as discussed on page 34 of Statement No. 8), the amount of leverage, or proportion of debt, in a firm's capital structure is directly related to the firm's financial risk and cost of equity. Mr. Rothschild's analogy to the measurement of weight on two scales is no analogy at all. Unlike weight, there is only one scale for measuring financial risk and that is the amount of leverage in a firm's capital structure. A firm's financial risk changes when the quantities of debt and equity capital, on which the measurement is based, are changed. For the Gas Group, the average market value of their debt is $1,462,908 and the book value of their debt is $1,373,169. Both of these measures are stated as dollar values; there has been no change in the units of measurement. Likewise for their equity. The average market value of the Gas Group's common equity is $2,561,288 and the corresponding book value is $1,511,290. Again, both are stated in dollars and there has been no change in the units of measurement. A measurement of financial risk that is based on a market-value capitalization cannot be applied directly to book-value capitalization if there is a material difference attributed to a change in financial risk between the two. Unlike weight where the relationship between the scales of measurement are fixed (i.e., the one pound equals 0.45359 kilograms), the financial risk associated with a market-value capitalization can be higher or lower than the financial risk associated with a book-value capitalization, depending on the quantities, stated in dollars, of debt and equity measured and their relative proportion to the total capitalization. Financial risk is measured as a percent of fixed-cost (i.e., senior) capital. That is to say, the quantities that are used to measure financial risk account for the different quantities of debt and equity that result from market and book valuations of capital.

According to Mr. Rothschild's analogy one loses weight by merely changing the calibration of the scale from pounds to kilograms. Mr. Rothschild's position that a cost of equity derived from market-valued capitalizations may be applied to a book-value capitalization is just like saying one kilogram is the same as one pound. This is of course incorrect, just as it is indisputable that there is more financial risk associated with a 54.30% common equity ratio than there is with a 65.62% common equity ratio. The company's risk-adjusted return associated with a market-value capitalization is different than its risk-adjusted return associated with a book-value capitalization. Therefore, in order to apply a measurement of a return measured based on a firm's market-value capitalization compared to a book-value capitalization, the measurement must be adjusted before it is applied to the firm's capitalization measured based on book value.

CAPITAL ASSET PRICING MODEL

Q. Do you have concerns regarding Ms. Maurer's application of the CAPM?

A. Yes. Ms. Maurer's CAPM analysis understates the cost of equity for a number of reasons: (i) her use of the yield on 10-year Treasury notes, (ii) her use of historical geometric means to calculate total market return, (iii) her failure to use leveraged adjusted betas, and (iv) her failure to make a size adjustment.

Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The Blue Chip report dated March 1, 2015, which Ms. Maurer apparently relied on, shows this comparison. For the second quarter of 2016, the gap was 0.6% (3.7% - 3.1%) between the yields on 30-year and 10-year Treasury obligations. This shows a systematic understatement of Ms. Maurer's CAPM returns. This understatement can be traced to extraordinary monetary policy actions taken by the Federal Open Market Committee ("FOMC") to deal with the persistent sluggishness in the economy. Part of the Fed's strategy in dealing with this issue is a much lower Fed Funds rate that has resulted in lower short-term interest rates. While the FOMC has reduced short-term rates to restore investor confidence in the credit markets, long-term interest rates have remained relatively higher and have trended higher recently. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return. Use of shorter term rates, such as Ms. Maurer's 10-year Treasury Notes yields, are more susceptible to Fed policy actions.

Q. **How has Ms. Maurer understated the risk-free rate of return?**

A. The support for her risk-free rate of return is shown on Schedule 11 of I&E Exhibit No. 1. There, she incorrectly gives the same weight to the yield on 10-year Treasury notes for the fourth quarter of 2014 as she does for the entire five year period 2016 through 2020. This approach leads to a seriously understated risk-free rate of return. There are a variety of problems with her approach. First, the yields on 10-year Treasury notes for the all four quarters of 2014 will all be history by the time new rates become effective in January 2016. Therefore, even if 10 year rates are used, it is necessary to correct the quarterly and annual data to be considered in the risk-free rate of return and the weights assigned to the forecast data presented by Ms. Maurer. I have revised her forecast below, based upon the Blue Chip reports dated June 1, 2015 and July 1, 2015. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2016	3.10%	3.75%
2017	3.70%	4.30%
2018	4.20%	4.70%
2019	4.40%	4.90%
2020	4.60%	5.10%
2021	4.60%	5.10%
Average	4.10%	4.64%

The resulting risk-free rate of return is 4.10% using the yield on 10-year Treasury Notes and 4.64% using the yield on 30-year Treasury Bonds.

Q. What are your observations regarding Ms. Maurer's use of the geometric mean?

A. Ms. Maurer has incorrectly used the geometric mean in her historic analysis of the total market returns (see page 3 of Schedule 10 of I&E Exhibit No. 1). The theoretical foundation of the CAPM requires that the arithmetic mean be used because it conforms to the single period specification of the model and it provides a representation of all probable outcomes and has a measurable variance. It has been established that the arithmetic mean best describes expected future returns -- the objective of the CAPM. The arithmetic mean provides the correct representation of all probable outcomes and has a measurable variance. In contrast, use of the geometric mean, which Ms. Maurer advocates, consists merely of a rate of return taken from two data points which would have no measurable variance (i.e., the dispersion of the returns cannot be calculated with a geometric mean). So while a geometric mean will capture the growth from an initial to a terminal value, it cannot provide a reasonable representation of the market premium in the context of the CAPM because the model requires a single period return expectation of investors. The arithmetic mean provides an unbiased estimate, provides the correct representation of all probable outcomes, and has a measurable variance.

As stated by Ibbotson:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the arithmetic or simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, not geometric, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) in order to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154

As such, the geometric mean should not be used in the CAPM.

Q. Are there later quotes available from the Ibbotson Yearbook that might lead to a different conclusion regarding the use of arithmetic means?

A. No. A careful reading of Ibbotson on this point indicates that its view for using arithmetic data in the CAPM has not changed in later publications of its Yearbook. In the 2014 Yearbook (see page 83), Ibbotson states that "... the arithmetic mean better represents a typical performance over single periods." The CAPM is a single-period model, i.e., it provides an annual return, that requires use of the arithmetic mean to conform with the specification of the model. Moreover, when applying the CAPM (see page 152), Ibbotson specifically states: "The equity risk premium is calculated by subtracting the arithmetic mean of the government bond income return from the arithmetic mean of the stock market total return."

Q. What are your observations concerning Ms. Maurer's calculation of the total market return?

A. Ms. Maurer's analysis is only partially correct. While her forecasted future returns (see page 3 of Schedule 10 of I&E Exhibit No. 1) are reasonable, the historical returns are understated because they use geometric means. The correct arithmetic mean provides returns of:

	Arithmetic Mean
5 yr S&P Composite Index Historical Return	16.45%
10 yr S&P Composite Index Historical Return	9.79%
20 yr S&P Composite Index Historical Return	11.89%
40 yr S&P Composite Index Historical Return	13.62%
62 yr S&P Composite Index Historical Return	12.50%
Average Historic Market Return	12.85%

Q. How should these results be used in the CAPM?

A. To calculate the market premium ("Rm – Rf") with both forecast return of 9.81% calculated by Ms. Maurer on page 1 of Schedule 11 of I&E Exhibit No. 1 and historical data that I present above, the market return would be 11.33% (9.81% + 12.85% = 22.66% ÷ 2). The CAPM cost rate must also reflect the yield on 30-yield Treasury bonds, and contain the adjusted beta for the financial risk associated with the book value capital structure (just like DCF) that I develop on Schedule 10 of Exhibit No. 400. With these data along with the size adjustment, I have corrected Ms. Maurer's CAPM as indicated below:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Gas Group	4.64%	+	0.90	(	11.33%	-	4.64%	) +	1.14%	=	11.80%

Q. Ms. Maurer also questions the need to further adjust the CAPM results for size differences. Please comment.

A. Ms. Maurer's arguments revolve around the purported distinction between regulated utilities and unregulated industrial companies. However, the <u>Wong</u> article that she relies upon was authored twenty (20) years ago, and employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The <u>Wong</u> article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because utilities continue to have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns.

Q. How does size affect the financial performance of a small company?

A. Examples of the financial consequences of external factors that can influence the financial performance of a small company include loss of a large customer and the effect of increasing treatment requirements.

Q. Mr. Rothschild also challenges the adjustment that you made to the results of the CAPM for the size of the Gas Group. Please respond.

A. A size adjustment is necessary because the financial impact of changes in specific dollar amounts of revenues and costs have a magnified influence on a small company because there are fewer dollars over which those revenues or costs can be spread. The SBBI/Morningstar Yearbook clearly demonstrates that the simple CAPM does not reflect the return that is associated with small size. As Ibbotson has stated:

> The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the line, indicating

that these deciles have had returns in excess of those appropriate for their systematic risk.

RISK PREMIUM METHOD

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity. So, while Mr. Rothschild and Ms. Maurer decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk.

Q. Please respond to Ms. Maurer's comments regarding your Risk Premium approach.

A. Ms. Maurer makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility ratesetting process. In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Ms. Maurer's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony, we are facing the prospect of increasing interest rates for the future and the market has increased yields on debt instruments. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.75% (4.75% interest rate on A-rated public utility bonds + 6.50% equity risk premium + 0.50% credit quality adjustment). As I noted previously, the yield on Baa-rated public utility bonds has risen to 5.13%, which indicates that the interest rate I used for Baa-rated debt in the Risk Premium approach of 5.25% (4.75% + 0.50%) is reasonable.

COMPARABLE EARNINGS

Q. Ms. Maurer and Mr. Rothschild have not used the Comparable Earnings approach. Please comment.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Because the Comparable Earnings method is derived from a firm's overall performance (i.e., its average return), the approach blends returns on a variety of projects that have produced returns above and below the cost of capital during the measurement period. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital. I have used this approach in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill established standards of a fair rate of return, i.e. namely, comparability and capital attraction.

The Comparable Earnings approach satisfies the comparability standard established in the Hope case. In addition, the financial community has expressed the view[4] that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets.

Q. Mr. Rothschild raises the issue of market returns versus book returns in his critique of your Comparable Earnings approach. Please comment.

A. The introduction of the market returns versus book returns, as part of his critique of my Comparable Earnings method, highlights the factors I discussed above regarding the DCF. As noted in my direct testimony, the problem with an unadjusted DCF arises when those returns are applied to a book value capital structure, rather than market capitalization. Unless we use the market values in the calculation of the weighted average cost of capital, then other methods, such as Comparable Earnings, that focus on book values should also be used.

RELATIVE RISK OF CPA

Q. Has Ms. Maurer recognized the higher risk of CPA when proposing her rate of return on common equity?

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[4] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

A. No. Her proposal is deficient in this regard. There is just no question that CPA has higher risk than her gas barometer group. Rather Ms. Maurer argues that CPA is no riskier than any other western Pennsylvania NGDC. But this observation misses the point entirely. Ms. Maurer does not use other western Pennsylvania NGDCs to measure the cost of equity, but instead measured it with her barometer group. None of the barometer group companies operate in western Pennsylvania with overlapping service territories. There are other risk factors that Ms. Maurer has not taken into account in her analysis. And, the availability of the DSIC is not a factor that will offset the Company's higher risk. Ms. Maurer claims that my position is that the DSIC has no effect on risk. Rather, my position is that the effect of accelerated cost recovery is already reflected in the cost of equity as measured by the barometer group, and that no additional consideration of the DSIC is required. Schedule 6 of Exhibit PRM-2R substantiates this position. Since those benefits are already reflected in the common stock prices of those companies, there is no need to further consider the effects of the DSIC on the cost of equity.

Q. **With regard to your discussion of credit quality and the associated adjustment, Ms. Maurer and Mr. Rothschild seem to question the validity of relying upon the ratings of NiSource. Please respond.**

A. The comparisons provided by Ms. Maurer on page 56 of her prefiled direct testimony show clearly that the credit quality rating is lower, and hence the cost of equity is higher for NiSource and by extension CPA. Yet, Ms. Maurer argues that the lower NiSource credit rating does not translate into a higher cost of equity for CPA. Mr. Rothschild goes on to allege that this results in double counting due to the adjustment for credit quality and use of CPA's rather than NiSource's capital structure. But as I have indicated previously, a comparison to the NiSource capital structures is inappropriate because it does not reflect the separation nor eliminate the merger debt. Contrary to Ms. Maurer's belief, I have identified the Company's weak interest coverages (see page 17 of my prefiled direct testimony) that likewise points to weak credit quality for CPA. As such, the Company's cost of equity is higher due to its lower credit quality traits, as I indicated in my direct testimony.

DSIC ADJUSTMENT

Q. Mr. Rothschild has recommended that CPA's equity allowance should reflect the risk reducing presence of the DSIC. Mr. Rothschild contends that the DSIC has reduced CPA's overall risk. Please respond.

A. It must be recognized that, in a typical year, CPA invests in both DSIC-eligible plant and non DSIC-eligible plant. The DSIC has no impact on non-DSIC investment in new plant and equipment (e.g., dollars spent on new business, information technology, etc.). Yet, Mr. Rothschild's proposal would influence the rate of return allowed on all classes of property - - DSIC-eligible and non DSIC-eligible.

Finally, Mr. Rothschild incorrectly assumes that on average 42% of the revenues of the companies in the barometer group are unaffected by the existence of a DSIC, if it is available, for those companies. But as I have shown, Mr. Rothschild's assumption is erroneous because 70%, on average, of the revenues for the barometer group are derived from regulated operations (see Schedule 2 of Exhibit PRM-2R). Moreover, there has been a proliferation of DSIC type mechanisms throughout the natural gas utility industry. This has recently been highlighted in the RRA Topical Special Report entitled "Gas Utility Infrastructure Investment" dated July 1, 2015, and included as Schedule 6 of Exhibit PRM-2R. Hence, any benefit that CPA may receive from the DSIC is already reflected in the market data for the Gas Group utilized by Mr. Rothschild and me to measure the Company's cost of equity.

<u>WNA Adjustment</u>

Q. Mr. Rothschild also argues that the WNA reduces risk which should be considered in the determination of the Company's equity return. Please respond.

A. Mr. Rothschild is incorrect on this point as well. As I fully documented on pages 8 and 9 of Statement No. 8, no adjustment to the cost of equity is warranted for the WNA because the risk attributes of the WNA are fully reflected in the cost of equity determination with market data derived from the Gas Group. I am also advised that the WNA for CPA only applies to residential usage, and contains a large (5%) deadband. As a result, CPA still has substantial risk in achieving its authorized return.

<u>SUMMARY</u>

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Rothschild and Ms. Maurer significantly understate the Company's cost of common equity. In an environment of higher interest rates that have developed recently, and since we are setting rates for 2016 for CPA, a 10.95% cost of equity provides a reasonable return for the Company.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rebuttal Exhibit PRM-2

COLUMBIA GAS OF PENNSYLVANIA, INC.

Schedules to Accompany

The Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity

and

Fair Rate of Return

DOCKET NO. R-2015-2468056

July 16, 2015

EXECUTION COPY

THIRD AMENDED AND RESTATED REVOLVING CREDIT AGREEMENT

among

NISOURCE FINANCE CORP.,
as Borrower,

NISOURCE INC.,
as Guarantor,

THE LENDERS PARTY HERETO,

BARCLAYS BANK PLC,
as Administrative Agent,

CREDIT SUISSE SECURITIES (USA) LLC
as Syndication Agent,

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
CITIBANK, N.A.
and
JPMORGAN CHASE BANK, N.A.,
as Co-Documentation Agents

BARCLAYS BANK PLC
CREDIT SUISSE SECURITIES (USA) LLC
THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.
CITIGROUP GLOBAL MARKETS, INC.
and
J.P. MORGAN SECURITIES LLC
Joint Lead Arrangers and Joint Bookrunners

Dated as of December 5, 2014

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ANNEXES, EXHIBITS AND SCHEDULES

THIRD AMENDED AND RESTATED REVOLVING CREDIT AGREEMENT, dated as of December 5, 2014 (this "***Agreement***"), among **NISOURCE FINANCE CORP.**, an Indiana corporation, as Borrower (the "***Borrower***"), **NISOURCE INC.**, a Delaware corporation ("***NiSource***"), as Guarantor (the "***Guarantor***"), the Lead Arrangers and other Lenders from time to time party hereto, the Co-Documentation Agents party hereto, **CREDIT SUISSE SECURITIES (USA) LLC**, as Syndication Agent and **BARCLAYS BANK PLC**, as administrative agent for the Lenders hereunder (in such capacity, the "***Administrative Agent***").

WITNESSETH:

WHEREAS, the Borrower, the Guarantor, certain Lenders and the Administrative Agent are parties to the Existing Credit Agreement (as defined herein) pursuant to which, among other things, the Lenders agreed to enter, subject to the terms and conditions set forth therein, into a revolving credit facility in an aggregate amount of $2,000,000,000; and

WHEREAS, the parties hereto have agreed to amend and restate the Existing Credit Agreement pursuant to the terms and conditions of this Agreement;

NOW, THEREFORE, the parties hereto hereby agree as follows:

ARTICLE I
DEFINITIONS

SECTION 1.01. Defined Terms. As used in this Agreement, the following terms have the meanings specified below:

"***ABR***", when used in reference to any Loan or Borrowing, refers to whether such Loan is, or the Loans comprising such Borrowing are, bearing interest at a rate determined by reference to the Alternate Base Rate.

"***Act***" means the USA PATRIOT Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)).

"***Additional Commitment Lender***" has the meaning assigned to such term in Section 2.21(d).

"***Administrative Questionnaire***" means an Administrative Questionnaire in a form supplied by the Administrative Agent.

"***Affiliate***" means, with respect to a specified Person, another Person that directly, or indirectly through one or more intermediaries, Controls or is Controlled by or is under common Control with the Person specified.

"***Agent Party***" has the meaning assigned to such term in Section 11.01(h).

"***Aggregate Commitments***" means the aggregate amount of the Commitments of all Lenders, as in effect from time to time. As of the date hereof, the Aggregate Commitments equal $1,500,000,000.

Annex A

PRICING GRID

The "Applicable Rate" for any day with respect to any Eurodollar Loan, ABR Loan, Facility Fee or LC Risk Participation Fee, as the case may be, is the percentage set forth below in the applicable row under the column corresponding to the Status that exists on such day:

Status	Level I	Level II	Level III	Level IV	Level V
Eurodollar Revolving Loans (basis points)	100	107.5	127.5	147.5	165
ABR Loans (basis points)	0	7.5	27.5	47.5	65
Facility Fee (basis points)	12.5	17.5	22.5	27.5	35
LC Risk Participation Fee (basis points)	100	107.5	127.5	147.5	165

For purposes of this Pricing Grid, the following terms have the following meanings (as modified by the provisos below):

"***Level I Status***" exists at any date if, at such date, the Index Debt is rated either A- or higher by S&P or A3 or higher by Moody's.

"***Level II Status***" exists at any date if, at such date, the Index Debt is rated either BBB+ by S&P or Baa1 by Moody's.

"***Level III Status***" exists at any date if, at such date, the Index Debt is rated either BBB by S&P or Baa2 by Moody's.

"***Level IV Status***" exists at any date if, at such date, the Index Debt is rated either BBB- by S&P or Baa3 by Moody's.

"***Level V Status***" exists at any date if, at such date, the Index Debt is rated either BB+ by S&P or lower or Ba1 by Moody's or lower, or, no other Status exists.

"***Status***" refers to the determination of which of Level I Status, Level II Status, Level III Status, Level IV Status or Level V Status exists at any date.

The credit ratings to be utilized for purposes of this Pricing Grid are those assigned to the Index Debt, and any rating assigned to any other debt security of the Borrower shall be disregarded. The rating in effect at any date is that in effect at the close of business on such date.

Provided, that the applicable Status shall change as and when the applicable Index Debt ratings change.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Bureau of Investigation & Enforcement – Set RR

Question No. I&E-RR-004:

Identify the proportion of assets used for and revenue derived from regulated operations for each of the companies in Mr. Moul's Gas Group.

Response:

The percentages of revenues, earnings and assets derived from regulated operations for the companies in Mr. Moul's Gas Group are shown in the chart below:

	Percent regulated		
	Revenues	Earnings	Assets
AGL Resources, Inc.	81.06%	83.36%	81.54%
Atmos Energy Corp.	68.66%	95.38%	95.70%
Laclede Group, Inc.	84.34%	87.11%	95.38%
New Jersey Resources Corp.	24.64%	64.96%	69.72%
Northwest Natural Gas	95.87%	90.72%	89.01%
Piedmont Natural Gas Co.	100.00%	88.34%	96.92%
South Jersey Industries, Inc.	61.04%	151.96% (1)	65.27%
Southwest Gas Corporation	66.65%	85.45%	93.58%
WGL Holdings, Inc.	48.67%	89.48%	81.84%
Average	70.10%	92.97%	85.44%

(1) Reflects losses in Wholesale Energy Operations, Retail Electric Operations, and On-Site Energy Production

THE WALL STREET JOURNAL.
WSJ.com

HEARD ON THE STREET | APRIL 26, 2010

Wall Street's Missed Expectations

By LIAM DENNING

Wall Street's sell-side analysts are a famously Panglossian tribe. But it turns out that they are actually too pessimistic when it comes to predicting company earnings, particularly in the wake of recession.

With 172 of the S&P 500's members having so far reported quarterly earnings, 143 have beaten their consensus forecast, according to data collated by Thomson Reuters. On average, their numbers came in 21% above the Street's collective wisdom.

Less than 40% of the index's members have reported, so the current score of 83% having beaten forecasts—easily the highest for any quarter since at least 1999—may not stand. But having a high percentage of companies beat the Street isn't unusual. Thomson's data show that, on average, 64% of companies have done so in any given quarter since the start of 1999, compared with 18% that miss. The average earnings "surprise" is 2%, although these data swing erratically.

This is less surprising than it appears. Corporate management, for better or worse, go to great lengths to guide analysts toward the right numbers. After all, the last thing you want to do is deliver a nasty surprise. Just ask Ingersoll Rand, which missed the consensus forecast by 11% on Friday and saw its shares plunge 8.5% at one point.

Analysts are also prone to the same greed and fear that fuel the financial markets' gyrations. The most optimistic quarter since 1999, in which only 52% of S&P 500 companies beat the consensus forecast, was the last three months of 2000, just as the tech bubble was turning to bust.

With that in mind, it is little wonder that pessimism has really taken hold recently, with the percentage of companies beating earnings forecasts well above average since the second quarter of 2009. But there could be more to this than mere psychology. So far this quarter, for example, 69% of S&P 500 companies that have reported have beaten revenue estimates, according to Thomson. The implication is that final demand is stronger than anticipated.

Tobias Levkovich of Citigroup points to the importance of labor. Corporate America cut costs rapidly as recession took hold. That helped offset some of the damage inflicted on earnings by falling sales. But the ranks of the unemployed weigh heavily on expectations for a recovery in sales. That leaves scope for surprisingly good revenue numbers, relative to estimates, which in turn provides great operating leverage at the profit line, given earlier cost cutting.

So there is reason to suspect analysts' expectations will continue to be trumped by better results as the current reporting season progresses. But at some point, that unemployment rate has to fall if optimism is to be restored on a sustainable basis.

—Liam Denning

Printed in The Wall Street Journal, page C8

Gas Group

Forecast CapEx

Company	2014	2015	2016	2017	2018	2019	Average	UPS, net	Percent
				Amounts in Millions					
AGL Resources	$742	$760	$802	$728	$799		$766	$8,643	8.86%
Atmos	$835	950	1000	1000	1000		$957	$6,031	15.87%
Laclede	$232	$300	$250	$250	$250	$250	$255	$1,777	14.37%
New Jersey	$187.90	$222.60	$233.70	$153.90			$200	$1,643	12.14%
NW Natural	125	125	125	125	125		$125	$2,063	6.06%
Piedmont	$477	$500	$530	$590			$524	$3,334	15.73%
South Jersey	$180	$211.20	$228.50	$157.30			$194	$1,859	10.45%
Southwest Gas	$375	$375	$375				$375	$3,486	10.76%
WGL	$286.30	$303.10	$372.80	$355.40	$359.50	$360	$340	$2,907	11.68%
Average									11.77%
Columbia Gas of Pennsylvania, Inc.		$196.872	$ 210.572	$230.803	$224.523	$218.856	$216	$1,270	17.04%

Gas Group

Internal Growth ("b x r") 3 to 5 Year Projections

Company	Dividends Per Share	Earnings Per Share	Book Value Per Share	Prior Y/E Book Value	Average Book Value	ROE	Payout Ratio	Retention Rate	Internal Growth Rate
AGL Resources, Inc.	$2.40	$4.65	$36.65	$34.40	$35.53	13.09%	51.61%	48.39%	6.33%
Atmos Energy Corp.	$1.90	$3.80	$36.65	$34.75	$35.70	10.64%	50.00%	50.00%	5.32%
Laclede Group, Inc.	$2.20	$4.20	$48.10	$45.10	$47.10	8.92%	52.38%	47.62%	4.25%
New Jersey Resources Cor	$0.98	$1.85	$15.65	$14.78	$15.22	12.16%	52.97%	47.03%	5.72%
NiSource Inc.	$1.20	$2.60	$25.55	$24.15	$24.85	10.46%	46.15%	53.85%	5.63%
Northwest Natural Gas	$2.10	$3.30	$33.85	$32.65	$33.25	9.92%	63.64%	36.36%	3.61%
Piedmont Natural Gas Co.	$1.47	$2.10	$20.40	$19.77	$20.09	10.46%	70.00%	30.00%	3.14%
South Jersey Industries, Inc	$1.35	$2.50	$18.40	$17.25	$17.83	14.03%	54.00%	46.00%	6.45%
Southwest Gas Corporation	$2.10	$4.25	$39.40	$37.25	$38.33	11.09%	49.41%	50.59%	5.61%
WGL Holdings, Inc.	$1.99	$3.35	$29.20	$27.84	$28.52	11.75%	59.40%	40.60%	4.77%
Average						**11.25%**	**54.96%**	**45.04%**	**5.08%**

External Growth ("s x v") 3 to 5 Year Projections

Company	2014 Book Value per Share	Stock Price	1-(B/P)	Common Shares Outst'g 2014	Common Shares Outst'g 2018-20	Com Shs. Growth x M/B	External Growth Rate	"b times r" plus "s times v"
AGL Resources, Inc.	$31.63	$49.46	0.3605	119.65	125.00	1.37%	0.49%	6.83%
Atmos Energy Corp.	$30.74	$53.20	0.4222	100.39	120.00	6.29%	2.66%	7.98%
Laclede Group, Inc.	$34.93	$52.49	0.3345	43.18	45.00	1.25%	0.42%	4.66%
New Jersey Resources Cor	$11.47	$29.84	0.6156	84.20	85.00	0.49%	0.30%	6.02%
NiSource Inc.	$19.54	$47.04	0.5846	316.04	325.00	1.35%	0.79%	6.42%
Northwest Natural Gas	$28.12	$44.45	0.3674	27.28	28.00	0.83%	0.30%	3.91%
Piedmont Natural Gas Co.	$16.80	$36.78	0.5432	77.88	80.00	1.18%	0.64%	3.78%
South Jersey Industries, Inc	$13.65	$26.31	0.4812	68.33	76.00	4.15%	2.00%	8.45%
Southwest Gas Corporation	$31.95	$53.01	0.3973	46.52	52.00	3.74%	1.49%	7.10%
WGL Holdings, Inc.	$24.08	$56.17	0.5713	51.76	50.00	-1.61%	[1]	4.77%
Average							**1.01%**	**5.99%**

Note: [1] Excluding negative value

Source: The Value Line Investment Survey, June 6, 2014

SCHEDULE ALR 4, Page 2

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) INDICATED COST OF EQUITY
BASED ON VALUE LINE'S FORECAST
GAS GROUP

		AGL Resources GAS	Atmos Energy Corp ATO	Laclede Group LG	New Jersey Res. NGR	N.W. Nat'l Gas NWN	Piedmont Nat'l Gas PNY	South Jersey Inds. SJI	Southwest Gas SWX	WGL Holdings WGL	Source
Value Line Date		3/6/2015	3/6/2015	3/6/2015	3/27/2015	3/6/2015	3/6/2015	3/6/2015	3/6/2015	3/6/2015	
Dividend	2015	$2.04	$1.56	$1.84	$0.62	$1.87	$1.31	$2.05	$1.62	$1.65	Value Line
	2016	$2.10	$1.64	$1.92	$0.70	$1.91	$1.35	$2.20	$1.74	$1.87	Based on Value Line, assuming constant dividend growth
	2017	$2.20	$1.72	$2.01	$0.74	$1.97	$1.39	$2.34	$1.85	$1.87	Based on Value Line, assuming constant dividend growth
	2018	$2.30	$1.81	$2.10	$0.79	$2.03	$1.43	$2.49	$1.97	$1.87	Value Line
	2019	$2.40	$1.90	$2.20	$0.84	$2.10	$1.47	$2.65	$2.10	$1.87	
Forecasted dividend growth rate		4.55%	5.03%	4.64%	6.27%	3.21%	2.88%	6.40%	6.47%	0.00%	Compound annual rate of growth in dividends from 2014 to 2017
Book Value	2015	$35.35	$31.85	$36.20	$37.25	$29.65	$17.40	$28.55	$32.30	$25.15	Value Line
	2019	$40.70	$36.65	$48.10	$43.95	$36.15	$20.40	$34.20	$32.65	$30.00	Value Line

Total return on equity to investor who purchased stock on 4/30/15 and sold stock on 4/30/2019
assuming Value Line projections of dividends and book value are correct and assuming
stock price grows at same rate as book value

Cash Flow from purchasing stock in 2015, receiving dividends through 2019, and selling the stock in 2019
Negative number in 2015 reflects cash outflow required to purchase stock
Cash flow sources are 1) dividends, and 2) proceeds of stock sale

		GAS	ATO	LG	NGR	NWN	PNY	SJI	SWX	WGL	Source
Stock Price	5/31/2015	$50.37	$54.02	$53.51	$25.20	$44.70	$37.29	$26.39	$54.46	$57.54	SCHEDULE ALR 3, Page 1
	5/31/2019	$57.99	$62.16	$71.10	$29.73	$54.50	$43.72	$31.61	$55.05	$68.64	Increase in stock price at same rate as forecasted increase in book value
VL Midpoint stock price forecast		$70.00	$62.50	$65.00	$30.00	$55.00	$37.50	$70.00	$62.50	$50.00	
Cash flow does not include 1Q dividend paid on March 31, 2015	1Q Dividend	0.51	0.39	0.46	0.145	0.465	0.32	0	0.365	0.463	
	2015	($48.84)	($52.85)	($52.13)	($24.73)	($43.30)	($36.30)	($24.34)	($53.21)	($56.15)	
	2016	$2.10	$ 1.56	$ 1.84	$ 0.62	$ 1.87	$ 1.31	$ 2.05	$ 1.62	$ 1.85	
	2017	$2.20	$ 1.64	$ 1.92	$ 0.70	$ 1.91	$ 1.35	$ 2.20	$ 1.74	$ 1.87	
	2018	$2.30	$ 1.72	$ 2.01	$ 0.74	$ 1.97	$ 1.39	$ 2.34	$ 1.85	$ 1.87	
	2019	$72.30	$64.31	$67.10	$30.79	$57.03	$38.93	$72.49	$64.47	$51.87	
	DCF	13.41%	7.27%	9.14%	7.63%	10.28%	4.54%	36.72%	7.28%	0.61%	This DCF result is an Internal Rate of Return computation made by the "IRR" function built into the Microsoft Excel spreadsheet. It is based on the actual cash flows shown from 2015 to 2019.
	Average DCF Result		10.76%								
	Median DCF Result		7.63%								

Regulatory Research Associates
REGULATORY FOCUS

RRA Topical Special Report July 1, 2015

GAS UTILITY INFRASTRUCTURE INVESTMENTS
~ The Who, What, When, Where, How, and Why ~

Overview

Infrastructure investments have long been a focus for natural gas local distribution companies (LDCs) in the U.S. Indeed, one of the central elements of the "regulatory compact," to which all regulated utilities are subject, requires the LDCs to provide safe and reliable service in exchange for a reasonable opportunity to earn a state-commission-determined "fair" rate of return on net assets. In parts of the country that have long been reliant on gas, LDC infrastructure is nearly as old as the communities it was constructed to serve and consists of materials that, over an extended period of time, are likely to degrade. In years past, gas distribution pipes were typically constructed using cast iron and unprotected steel, and for several decades, this equipment served customers well. However, advances in modern technology and several high-profile incidents (e.g., a 2014 explosion in East Harlem, New York caused by a gas leak in an 1887-vintage main, and a 2010 explosion in San Bruno, California caused by a compromised pipeline) suggest that wide swaths of gas utility infrastructure need to be replaced, and at an accelerated pace, in the coming years if similar occurrences are to be prevented in the future.

Aftermath of 2010 San Bruno, California Pipeline Explosion
Source: Wikipedia

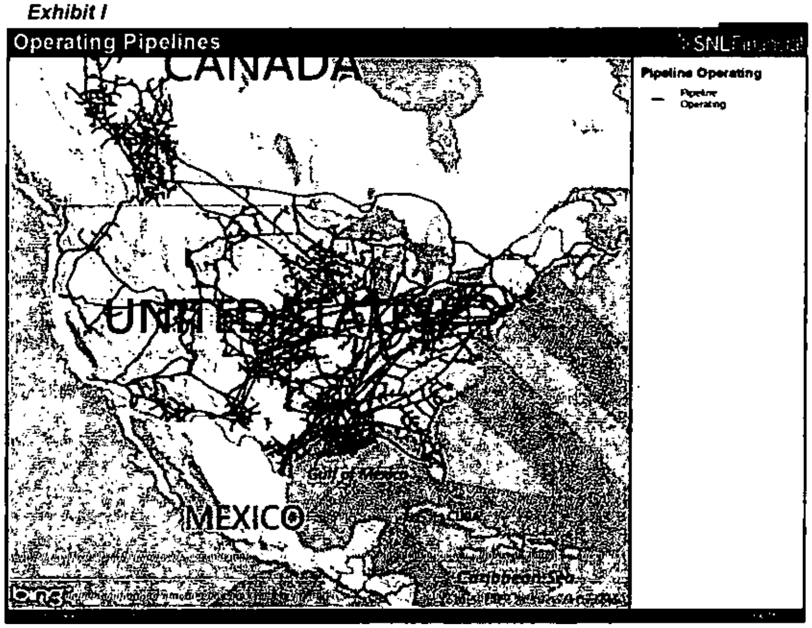
Aftermath of 2014 East Harlem, New York Pipeline Explosion
Source: Wikipedia

Remnants of a defunct gas pipeline
Source U.S. Pipeline & Hazardous Materials Safety Administration

In fact, the U.S. Department of Transportation (DOT), which regulates the safety of certain gas pipelines, announced a "Pipeline Safety Action Plan" in 2011, calling for industry stakeholders to pursue policies that will support the accelerated replacement of at-risk LDC infrastructure with more resilient materials, including protected steel and plastic. According to the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA), which regulates pipeline safety, roughly 4% of the nation's 1.2 million miles of gas distribution mains is made of material that the industry opines is ripe for replacement (e.g., cast iron, unprotected steel, and certain older types of plastic); a similar percentage of the country's roughly 65 million distribution service lines (i.e., the pipes that run from a larger main to a customer's meter) is in need of replacement.

Notably, the DOT's plan calls for state utility commissions to adopt constructive ratemaking policies that would help make such a plan a reality. Although many commissions had previously approved replacement plans for the utilities under their purview and adopted supportive ratemaking practices to address the related costs, the DOT's plan marked a turning point for regulators in other jurisdictions to give the issue increased attention. But the industry is not only focused on addressing safety and reliability. As shown in Exhibit I, in certain parts of the country, primarily the West and the Northeast, natural gas infrastructure is rather sparse, due to the fact that these regions have historically relied more heavily on other fuel sources to meet their heating and power generation needs. As these areas look to capitalize on a sustained period of low natural gas prices and embrace the importance of fuel diversity to maintaining competitive energy prices, they have begun to move forward with plans for an extensive build-out of their natural gas transmission and distribution systems. Regardless of where the industry's capital expenditures dollars are going, one thing remains clear -- no two regulatory jurisdictions treat these investments in exactly the same manner, suggesting that the investment community needs to be aware of the cost recovery frameworks in place for these investments.

Exhibit I



Natural gas pipelines in operation, as of June 30, 2015
Source: SNL Financial

Who Regulates What

Broadly speaking, in the U.S., the Office of Pipeline Safety, within PHMSA, is tasked with issuing gas transmission and distribution safety regulations pertaining to construction, operation, and maintenance. The PHMSA also inspects pipelines and is permitted to enforce violations of federal pipeline safety laws and regulations. Each of the states plays a role in establishing supplemental safety-related criteria for the pipelines in their jurisdictions. The National Transportation Safety Board investigates pipeline accidents and issues recommendations to regulatory agencies, utilities, and industry trade groups following its reviews of such incidents. The Federal Energy Regulatory Commission regulates the interstate sale and transportation of natural gas, and has a comprehensive framework in place for determining the rates charged by interstate pipeline operators.

At the state level, the utility commissions are responsible for determining the rates that can be charged by the LDCs for gas distribution service and intrastate pipeline service. Each of the state commissions has broad statutory authority to economically regulate their jurisdictional LDCs, and historically, infrastructure build-outs were addressed in the context of base rate proceedings. A utility that wanted to construct a new main, for example, was generally permitted to do so as part of the company's franchise agreement, and the related costs were subject to review in a full rate case. In light of recent high-profile incidents, such as the two noted above, and in response to the federal government's prodding, comprehensive infrastructure replacement programs are being developed across the U.S. and the state utility commissions are keenly aware of what's at stake. Many jurisdictions are utilizing their traditional ratemaking authority to approve the utilities' accelerated infrastructure replacement programs and are not necessarily dependent on their legislatures passing enabling legislation.

Resource Plans and Pre-Approval Requirements

In some jurisdictions, the LDCs are required to file formal resource plans with their state utility commissions. These plans typically include the investments the utility intends to make in the coming years, allowing the commission to get a better sense of the magnitude of the potential costs. Although the costs associated with these projects tend to be much lower than the costs their electric utility peers incur to construct new generation and transmission, regulators are cognizant of the potential impact on ratepayers.

Certain jurisdictions require projects to be pre-approved prior to construction, giving the utilities some cost-recovery certainty. A pre-approval requirement ensures that any concerns regarding the scope of a project are addressed before ground is broken, thereby limiting the likelihood that a project will be found to be imprudent after it is completed. Pre-approval requirements are less pervasive on the gas side of the utility industry, as LDC infrastructure investments are primarily made for safety reasons and do not generally prompt stakeholder backlash.

Resource plan filing and pre-approval requirements vary considerably from state to state. For example, in Indiana, state law requires the LDCs to obtain Indiana Utility Regulatory Commission approval of "seven-year plans" that encompass the investments they intend to make if they are to be allowed to recover the related costs through a rate rider. The URC must review the projects before construction commences to ensure they meet certain statutory requirements for inclusion in the rider. Once the company receives URC approval of its plan, project-related work can commence.

Alternatively, in Kansas, the LDCs are not required to file formal resource plans and infrastructure projects do not require Kansas Corporation Commission pre-approval. However, the KCC conducts reviews of actual project-related expenditures in the context of rider-related proceedings to ensure that they meet certain statutory requirements. The KCC may review the "reasonableness and prudence" of these costs in the company's next rate case, and if any of the costs are found to be imprudent, an adjustment would be made to reflect the disallowed costs.

Methods of Cost Recovery

By default, cost recovery of utility investments is addressed in base rate cases; however, in certain jurisdictions, the traditional rate case model, which is often protracted and highly contentious, may not be the ideal forum for dealing with the recovery of these costs. Rate cases frequently take a year (or longer) to litigate, and the utilities' cost recovery efforts may be further hampered in those jurisdictions that employ the use of an historical test year. In addition, unlike investments that a utility makes to add new customers to its system, infrastructure replacement projects, which increase the resiliency of the pipes being used to serve existing customers, are essentially "non-revenue-producing" investments when they are completed. In the absence of a supportive ratemaking framework, these projects may not be as enticing for the utility because its earnings and cash flows may be adversely affected. Thus, rate riders, which allow the utility to collect project-related costs between base rate proceedings, mitigate the effects of "regulatory lag" and play a prominent role in facilitating the replacement of aging infrastructure in a timely manner.

For regulators in those jurisdictions that do not allow these investments to be recovered through rate riders, a common theme seems to be that these riders would constitute "single-issue ratemaking," thereby jeopardizing the legality of their use. In addition, some commissions are hesitant to approve these riders for fear of giving the utilities less of an incentive to minimize the costs of a replacement project. Generally, the utilities contend that the commissions' ability to review project-related costs is bolstered by the fact that these investments can be addressed outside of the "noise" of a typical base rate case, and that rate riders can be effective in addressing cost recovery concerns.

As an example of just how far regulators have come in recent years in understanding the importance of the LDCs' investments, Exhibit II on the next page shows the Missouri Public Service Commission's reluctance, in 1997, to approve a rider that would have permitted Missouri Gas Energy (MGE) to recover certain replacement costs between rate cases. As shown below, the PSC was concerned that the rider would constitute "single-issue ratemaking," a concern that was shared by many other state commissions at the time. MGE, which is now a subsidiary of the Laclede Group, ultimately received approval several years later to implement an "infrastructure system replacement surcharge" following the enactment of enabling legislation.

In recent years, several jurisdictions have taken a proactive approach in addressing the matter, including Illinois and Maryland, as shown in Exhibits III and IV on the next page. State legislatures have begun to do their part by codifying their commissions' ability to authorize the use of infrastructure replacement riders, while regulators in other jurisdictions are increasingly relying on tools they have at their disposal to help bring about large-scale investment over an accelerated timeframe. According to Regulatory Research Associates, gas infrastructure riders have been adopted in about two-thirds of all jurisdictions; several other jurisdictions have formulaic-based ratemaking frameworks, through which the costs of these investments are implicitly addressed on a timely basis.

The table on page 5 provides insight into the nature of the resource planning, pre-approval, and cost recovery processes in place for each of the regulatory jurisdictions followed by Regulatory Research Associates, and the details that begin on page 6 are intended to provide a complete picture of the state-specific policies.

Exhibit II

Acquisition Savings Adjustment

The company proposed an expense adjustment equal to 50% of the achieved, ongoing savings ($14.7 million) resulting from SUG's acquisition of the gas properties from WR. (A settlement adopted in 1994 allows MGE to request recovery of benefits resulting from the acquisition.) The Staff contended that the proposal "imputes" expenses to ratepayers which were not actually incurred. The Commission determined "that MGE's acquisition savings adjustment should be rejected in total because adoption of this adjustment would be contrary to the provision of natural gas service based on the costs of providing such service and because MGE's experimental gas cost incentive mechanism already rewards MGE's shareholders for making financially sound gas procurement decisions." (See the March 1996 Annual Review for information regarding MGE's experimental purchased gas incentive mechanism.) This ruling, and the concomitant income tax adjustments, reduced the revenue requirement by a total of $9.8 million.

Weather Normalization Adjustment/Weather Normalization Clause

The revenue requirement was reduced by roughly $2 million because the PSC adopted the Staff's recommendation to use 30-year data to establish "normal" temperatures for ratesetting purposes. MGE proposed using a ten-year heating-degree-day average. The PSC also rejected a company-proposed weather normalization clause (WNC) and stated that if it were to authorize a WNC similar to that proposed, the "Commission would seriously consider a downward adjustment to the return on equity."

Gas Safety Project Rider

In conjunction with the incentive regulation rider discussed below, MGE proposed a gas safety project rider (GSPR). The company claimed that it spends more than $20 million annually on safety line replacements, and contended that timely rate recognition is essential to its financial well being. Under the GSPR, rates would have automatically increased annually following a 45-day Staff review period, to reflect the revenue requirement impact of plant additions completed by March 31 of each year. The PSC rejected the GSPR because it would constitute single-issue ratemaking, which is unlawful in Missouri.

Source: RRA Rate Case Final Report, Missouri Gas Energy, Jan. 28, 1997

Exhibit III

Sec. 5-111. Natural gas performance reporting.

(a) The General Assembly recognizes that for well over a century Illinois residents and businesses have relied on the natural gas utility system. The General Assembly finds that in order for a natural gas utility to provide safe, reliable, and affordable service to the State's current and future utility customers, a utility must refurbish, rebuild, modernize, and expand its infrastructure and adequately train its workforce on appropriate operations procedures and policies designed to effectively maintain its infrastructure

Source: Illinois Senate Bill 2266, enacted July 5, 2013, Illinois General Assembly

Exhibit IV

Chapter 161

(Senate Bill 8)

AN ACT concerning

Gas Companies – Rate Regulation – Infrastructure Replacement Surcharge

FOR the purpose of authorizing a gas company to recover certain costs associated with certain gas infrastructure replacement projects through a certain gas infrastructure replacement surcharge on customer bills; requiring project cost calculations to include certain elements; specifying when costs shall be collectible; specifying how the pretax rate of return shall be calculated and adjusted and what it shall include; prohibiting a certain monthly surcharge from exceeding a certain amount for certain customers; providing for the allocation of certain costs among customer classes; providing that certain adjustments for return on equity shall only be considered and determined in a certain base rate case; requiring the Public Service Commission to consider certain factors when establishing revenue requirements; authorizing the Commission to hold a public hearing on a plan within a certain period of time; requiring the Commission to take final action on a plan within a certain period of time; requiring the Commission to take final action on an amendment to an

Source: Maryland Senate Bill 8, enacted May 2, 2013, Maryland General Assembly

Regulatory Pre-Approval/Cost-Recovery Processes for LDC Infrastructure Projects

as of June 30, 2015

Juris.	Formal Resource Plan	Project Pre-Approval	Cost Recovery Limitations	Recovery Outside Rate Case
AL	–	–	–	–
AK	–	–	–	–
AZ	–	–	✓	✓
AR	–	–	–	✓
CA	–	✓	–	–
CO	–	–	–	✓
CT	✓	✓	✓	✓
DE	–	–	–	–
DC	–	✓	✓	✓
FL	–	✓	–	✓
GA	–	✓	–	✓
HI	–	–	–	–
ID	✓	–	–	–
IL	✓	–	✓	✓
IN	✓	✓	✓	✓
IA	–	✓	–	✓
KS	–	–	✓	✓
KY	–	✓	–	✓
LA-PSC	–	–	–	✓
LA-NOCC	–	–	–	–
ME	–	–	✓	✓
MD	–	✓	✓	✓
MA	–	✓	✓	✓
MI	–	✓	–	✓
MN	–	✓	–	✓
MS	–	–	–	✓
MO	–	–	✓	✓
MT	–	–	–	–
NE	–	–	✓	✓
NV	–	✓	✓	✓
NH	✓	–	–	✓
NJ	–	✓	–	✓
NM	✓	–	✓	–
NY	–	–	✓	✓
NC	–	✓	–	✓
ND	–	–	–	–
OH	–	✓	✓	✓
OK	–	–	–	✓
OR	✓	–	✓	✓
PA	–	–	✓	✓
RI	✓	✓	–	✓
SC	–	–	–	✓
SD	–	–	–	–
TN	–	–	–	✓
TX	–	–	–	✓
UT	✓	✓	✓	✓
VT	✓	–	–	✓
VA	–	✓	–	✓
WA	✓	–	–	✓
WV	–	–	–	–
WI	–	✓	–	–
WY	–	–	–	–

Source: Regulatory Research Associates, Inc./SNL Energy

State-by-State LDC Infrastructure Pre-Approval/Cost-Recovery Provisions

Please Note: Abbreviations used in this section of the report are listed on page 16.

ALABAMA--The LDCs are not required to file resource plans with the PSC. Laclede Group subsidiary Alabama Gas and Sempra Energy subsidiary Mobile Gas Service (MGS) recover their main/pipeline safety enhancement and upgrade costs through their respective Rate Stabilization and Equalization (RSE) mechanisms. In addition, MGS utilizes a Cast Iron Main Replacement factor to recover costs associated with the replacement of cast iron mains and associated services where such costs have not otherwise been recovered through the RSE mechanism.

ALASKA--The state has no gas integrated resource planning (IRP) process, nor are there any provisions for pre-approval or expedited treatment of specific projects or programs. Gas infrastructure investment for AltaGas Ltd. Subsidiary ENSTAR Natural Gas is addressed in base rate cases and is subject to after-the-fact prudence reviews.

ARIZONA--The jurisdiction does not have a resource planning process in place for the LDCs. In 2003, the ACC issued a policy statement addressing gas-related infrastructure investments. The LDCs are permitted to request implementation of alternative cost recovery mechanisms for costs related to new pipeline and storage projects. Most gas infrastructure costs are recovered through a traditional rate case process. Southwest Gas Corp. has riders in place to recover costs related to its customer-owned yard line (COYL) replacement program and its Transmission Integrity Management Program (TRIMP). The COYL rider may not exceed $0.01 per therm in any year; the TRIMP rider does not have any cost-recovery limitations. The return on equity (ROE) used in these riders is the equity return authorized the company in its most recent rate case. Fortis subsidiary UNS Gas recovers its infrastructure investments solely through base rates.

ARKANSAS--The LDCs are not required to file resource plans with the PSC. Generic infrastructure investments are addressed in the context of base rate proceedings. The utilities are permitted to recover a return of, and on, investments made pursuant to their gas transmission and distribution "integrity management programs" through a monthly adjusted system safety enhancement (SSE) rider, in the case of Arkansas Oklahoma Gas, or a main replacement program (MRP) rider for CenterPoint Energy subsidiary CenterPoint Energy Resources and SourceGas LLC subsidiary SourceGas Arkansas. MRP/SSE projects do not require PSC pre-approval, but are subject to a compliance audit for a five-year period after the date of the filing. Any amounts that do not conform to the rider's terms are to be subject to refund. The SSE and MRP riders are not "exact recovery" riders, and as such, no true-up is required. The rate-of-return parameters adopted in the company's most recent Arkansas-jurisdictional base rate case are to be used to calculate rate changes under the SSE/MRP riders. Amounts included in the SSE/MRP riders are to be included in the company's base rates at the conclusion of its next rate case. Certain utilities also use riders for costs associated with relocating "at-risk meters" and pipes that governmental agencies require to be moved.

CALIFORNIA--The LDCs are not required to file resource plans with the PUC. However, all infrastructure projects that are expected to cost more than $50 million require a PUC determination of need. In addition, the PUC establishes an appropriate cost for the project, and this cost is expected to be ultimately included in rates. Justification is required for costs greater than the specified level. No riders or clauses are in place to facilitate the recovery of main/pipeline replacement costs by the state's gas utilities. California's major gas LDCs typically file general rate cases every three years utilizing forecasted test years, and the PUC typically authorizes a rate change for the test year, and additional ("attrition") rate changes for each of the two years following the test year.

Over the last few years, the PUC has required PG&E Corp. subsidiary Pacific Gas and Electric and Sempra Energy subsidiaries Southern California Gas and San Diego Gas & Electric to make certain expenditures as part of the companies' Pipeline Safety Enhancement Plans. However, the required expenditures are not being recovered through special riders or clauses, but rather through the companies' general rate cases.

COLORADO--The LDCs are not required to file resource plans with the PUC and their infrastructure investments do not require PUC pre-approval for SourceGas LLC subsidiary SourceGas Distribution and Atmos Energy. Cost recovery of these projects is considered after the investment is in service through the base rate case process. Xcel Energy subsidiary Public Service Co. of Colorado has a rider in place to facilitate recovery of costs related to its infrastructure replacement program. This rider provides for the recovery of forecasted investment and the related O&M for specific projects and programs. No cost recovery cap is in place; however, the costs may be challenged after the investments are made and when cost recovery is sought. The company is to utilize the authorized ROE from its most recent base rate cases to calculate prospective rate adjustments under this rider. Non-replacement investment is addressed in base rates.

CONNECTICUT--Eversource Energy subsidiaries Yankee Gas Services (YGS) and Connecticut Light & Power, and UIL Holdings subsidiaries Connecticut Natural Gas (CNG) and Southern Connecticut Gas are subject to a comprehensive energy plan to expand natural gas service in the state. Legislation enacted in 2013 calls for the establishment of a mechanism for the timely rate recognition of capital expenditures made by gas utilities. The LDCs must submit a biennial forecast of natural gas demand and supply. Typically, LDC infrastructure-related investments are recovered through the rate case process. In a recent overearnings investigation for YGS, the company agreed as part of a PURA-approved settlement to forego requesting a distribution integrity management plan (DIMP) tracking mechanism prior to new base rates going into effect. Rates for YGS are to be frozen until Jan. 1, 2017.

CNG has a DIMP in place that allows for recovery of the costs associated with main replacement activities between rate cases. If CNG does not spend the full amount approved for these projects in any year, the difference is to be made up the following year. CNG is permitted to spend more than the amounts approved by the PURA; however, for incremental amounts greater than 15%, the company must obtain PURA approval. Ratepayers do not see a separate charge on their bills. Instead, the DIMP charge is included in base distribution rates. In approving the DIMP for CNG, the PURA indicated that "while a cap may prove necessary," it did not impose one. A cap may be imposed at a later date if costs were to become "burdensome for ratepayers."

DELAWARE--The state has no gas IRP process, nor are there any provisions for pre-approval or expedited treatment of specific projects or programs. Pepco Holdings subsidiary Delmarva Power & Light's and Chesapeake Utilities' gas infrastructure investment is addressed in base rate cases, subject to after-the-fact prudence reviews.

DISTRICT OF COLUMBIA--There is no comprehensive IRP process in place. Gas infrastructure investment is for the most part addressed in base rate cases and is subject to after-the-fact prudence reviews. The PSC has granted pre-approval of individual programs such as Vintage Mechanical Coupling Replacement and Encapsulation Program (VMCREP) for WGL Holdings subsidiary Washington Gas Light (WGL), with recovery of the related costs through a surcharge. Recoverable amounts were capped at $28 million (approved in 2009). Separately in January 2015, the PSC approved a $1 billion, 40-year Accelerated Pipeline Replacement Program (APRP) for WGL; the PSC approved a surcharge mechanism for recovery of the first five years of the program, with an estimated five-year cost of $110 million. The surcharge revenue requirements reflect the return parameters approved in WGL's most recent rate case; and, VMCREP and APRP expenditures are subject to annual audits/prudence reviews.

FLORIDA--The state does not have a gas IRP process in place. In 2012, the PSC approved a Cast Iron/Bare Steel Pipe Replacement Rider for TECO Energy subsidiary Peoples Gas System (PGS). The rider enables PGS to recover, through an annual surcharge, the costs associated with accelerating the replacement of cast iron and bare steel distribution pipes on its system over a 10-year period beginning Jan. 1, 2013. Under the rider, PGS is authorized to spend an additional $7 million per year on distribution pipe replacement; the company previously was authorized to spend $1 million annually, as established by the PSC in 2009 in the company's last general rate case. However, effective Jan. 1, 2013, the company is authorized to spend $8 million per year and earn a return on its additional investment equivalent to its cost of capital, as reflected in PGS' earnings surveillance report for December of each year, incorporating the company's currently authorized return on equity of 10.75%. Also in 2012, the PSC approved similar riders, the Gas Reliability Infrastructure Programs, for the considerably smaller gas utilities Florida Public Utilities and the Florida division of Chesapeake Utilities. AGL Resources utility Florida City Gas does not have a similar rider in place and recovers these costs through base rates.

GEORGIA--The LDCs are not required to file resource plans with the PSC. A Strategic Infrastructure Development and Enhancement (STRIDE) program is in place for AGL Resources subsidiary Atlanta Gas Light (ATGL) that provides for the company to invest in infrastructure improvements over the years 2009 through 2019. Every four years, ATGL is required to file for PSC review and approval of its proposed program for the subsequent four years. The costs associated with the program's investment are to be included in base rates each October 1. ATGL tracks any net over- or under-collected amounts, and the company is to issue a credit or surcharge reflecting any net over- or under-recovery at the conclusion of the program. Cost recovery includes a return on capital investment equal to the most recent overall return authorized for ATGL by the PSC. Liberty Utilities (Peach State Natural Gas) has a pipe replacement surcharge in place.

HAWAII--Natural gas is not produced in Hawaii. However, on a limited basis, synthetic natural gas is delivered through a distribution system owned by a privately-held company. The gas is produced at a single plant, and there are no competing suppliers in the state.

IDAHO--Avista Corp. and MDU Resources subsidiary Intermountain Gas are required to submit integrated resource plans detailing current and projected spending needs for a five-year period. Recovery of plan investment occurs, through base rates, once in service.

ILLINOIS--State law permits the ICC to authorize the LDCs to use a monthly adjusted rider to recover certain costs associated with investments in "qualified infrastructure plant" (QIP). The law applies to the state's largest LDCs, namely AGL Resources subsidiary Northern Illinois Gas (NI-Gas), Ameren Corp. subsidiary Ameren Illinois (AI), and WEC Energy Group subsidiary Peoples Gas Light and Coke (Peoples). The QIP rider, which is to sunset at year-end 2023, is to provide for recovery of, and a return on, the costs associated with the utilities' infrastructure replacement programs and, in the case of AI, smart-meter-related installation activities. QIP-eligible investments must be in-service and cannot increase the utility's revenues by connecting to new customers. The utilities are required to annually submit certain details to the ICC regarding their QIP investments, including each project's estimated costs and its priority relative to other projects. These filings are essentially the utilities' resource plans.

In any given year, the amount of each utility's QIP investments eligible to be included in the rider is limited to the lesser of its QIP investments for that year, or the amount by which its QIP investments for that year exceeds a base level. The base level is equal to the average of the utility's total depreciation expense for the years 2006-2010. Amounts included in the QIP rider are to be trued-up annually and are to reflect the rate-of-return parameters authorized by the ICC in the company's most recent rate case. The ICC is required to render QIP-related rate decisions within four months of the utility's initial filing. Amounts included in the QIP rider are to be included in the company's base rates at the conclusion of its next rate case. The average annual rate increases approved under the rider are to be limited to 4%, and may not exceed 5.5% in any given year. The QIP law does not apply to Berkshire Hathaway Energy subsidiary MidAmerican Energy and WEC Energy Group subsidiary North Shore Gas, and these companies recover the costs associated with their infrastructure investments through base rates using after-the-fact prudence reviews.

INDIANA--State law permits the URC to authorize the utilities to implement a rider for recovery of the costs associated with certain gas infrastructure expansion projects, including those intended to improve safety or reliability, modernize the utility's system, or improve an area's economic development prospects. Prior to implementing the rider, the utility is required to file a "seven-year plan" that includes details of the projects being considered by the company.

The riders approved by the URC are to be adjusted semi-annually, are to include a cash return on construction work in progress, and are to provide for recovery of 80% of all eligible depreciation expenses, operation and maintenance costs, property taxes, and a return that is to be calculated using the utility's weighted average cost of capital. The URC may consider, in the calculation of the utility's overall cost of capital, the ROE specified in the company's most recent base rate case. The remaining 20% of all eligible costs, and the related return, are to be deferred for inclusion in the utility's next base rate case. The URC is prohibited from approving a rider-related rate increase that results in an average aggregate increase in the utility's total retail revenues of more than 2% in a 12 month period. Any incremental amounts would be deferred for recovery in a future rate case, which the utility is required to file prior to the expiration of its seven-year plan.

NiSource subsidiary Northern Indiana Public Service (NIPSCO), and Vectren Corp. subsidiaries Indiana Gas and Southern Indiana Gas & Electric have received URC approval for their seven-year plans and currently utilize an accompanying rider; however, the legality of these seven-year plans was called into question by a recent Indiana Court of Appeals ruling that found that NIPSCO did not include sufficient detail for the latter years of its electric plan to justify its approval (see the RRA article dated 4/10/15).

IOWA--The LDCs are not required to file resource plans with the IUB. Routine infrastructure investments are addressed in the context of base rate proceedings. State law permits the utilities to file for IUB approval of a "capital infrastructure investment automatic adjustment mechanism" to facilitate recovery of the costs associated with certain gas distribution projects that are: beyond the direct control of management; subject to sudden fluctuations; an important factor in determining the total cost of infrastructure investment used to serve customers; and, readily, precisely, and continuously segregated in the utility's accounting records. Statutes require the utilities to provide, in their request for rate recovery of these investments, justification for the projects' inclusion in the rider. There are no limitations on the amounts that can be recovered through the rider. Black Hills Corp. subsidiary Black Hills/Iowa Gas Utility has such a rider in place (the "system safety maintenance adjustment"); the return used to calculate the related rate adjustments is the cost of debt approved in the company's most recent rate case, and rate adjustments occur no more frequently than annually. No such mechanism is currently in place for Alliant Energy subsidiary Interstate Power & Light or Berkshire Hathaway Energy subsidiary MidAmerican Energy.

KANSAS--The LDCs are not required to file resource plans with the KCC. Routine infrastructure investments are addressed in the context of base rate proceedings. Legislation enacted in 2006 permits the LDCs to request KCC approval of a gas system reliability surcharge (GSRS) rider to recover, between base rate proceedings, the costs associated with distribution system replacement projects, subject to an annual true-up. The utilities may request KCC approval of GSRS riders if: the related projects are undertaken to comply with federal or state safety requirements; infrastructure relocation projects are necessary due to construction or improvement of public roads; and, the utility had a base rate case decided within the preceding five years, or is the subject of a pending rate case. GSRS projects do not require KCC pre-approval, but the Commission conducts a review of actual project-related expenditures in the context of the GSRS proceedings to ensure that they meet the requirements of the GSRS statute. The KCC may review the "reasonableness and prudence" of these costs in the company's next rate case, and if any of the costs are found to be imprudent, an adjustment would be made in a future GSRS filing to reflect the disallowed costs.

The capital structure and rate-of-return parameters used to calculate GSRS-related rate changes are those authorized by the KCC in the company's most recent base rate case. However, if the case was resolved via a "black-box settlement" that did not specify these parameters, the Commission uses the average of the values that had been supported by the company in the case and those that were recommended by the KCC Staff. GSRS balances are rolled into base rates in its next rate case. GSRS riders may be used for up to five years (or up to six years under certain circumstances) and the utilities must file new rate cases if their riders are to remain in place. GSRS rate changes may not be requested more frequently than every 12 months. Annualized GSRS revenues may not exceed 10% of the utility's base revenue level, as approved in its most recent rate case. GSRS rate changes are not permitted if they are less than 0.5% of the utility's base revenue level, or $1 million, whichever is lower. Atmos Energy, ONE Gas subsidiary Kansas Gas Service, and Black Hills Corp. subsidiary Black Hills/Kansas Gas Utility have GSRS riders in place.

KENTUCKY--The utilities are not required to file resource plans with the PSC; however, certain utilities file information that is considered the equivalent of a resource plan. Routine infrastructure investments are addressed in the context of base rate proceedings. The utilities generally file for PSC pre-approval of their projects; the Commission conducts reviews of actual project-related expenditures in the context of cost-recovery proceedings. State law permits the Kentucky PSC to approve the use of accelerated main replacement program (AMRP)/pipe replacement program (PRP) riders for the LDCs, and the Commission's authority to do so has been upheld on appeal to the Kentucky Supreme Court. A utility's AMRP/PRP rider (or in the case of Louisville Gas & Electric, the "gas line tracker") reflects the rate-of-return parameters adopted by the PSC in the company's most recent base rate case. The riders are updated and trued-up annually and, for most customers, the revenue requirement is collected as a fixed monthly charge. Atmos Energy, NiSource subsidiary Columbia Gas of Kentucky, Delta Natural Gas, and PPL Corp. subsidiary Louisville Gas & Electric currently utilize these riders; Duke Energy subsidiary Duke Energy Kentucky does not.

LOUISIANA PSC--The utilities are not required to file resource plans with the Commission; however, certain utilities file information that is considered the equivalent of a resource plan. Atmos Energy has a formula rate plan mechanism in place in Louisiana, through which it recovers the costs of its infrastructure upgrades for its Louisiana Gas Service and TransLouisiana Gas divisions. Entergy Gulf States Louisiana and CenterPoint Energy subsidiary CenterPoint Energy Resources have similar frameworks in place whereby the companies recover their costs related to infrastructure upgrades.

LOUISIANA NOCC--No formal IRP or pre-approval processes are in place for Entergy Corp. subsidiary Entergy New Orleans (ENO), the only LDC operating in the jurisdiction. There are no infrastructure-related riders in place, and ENO's formula rate plan expired in 2012. The company recovers infrastructure investments solely through base rates.

MAINE--Gas service is available on a limited basis in the state. The LDCs are not required to file resource plans with the PUC. To encourage the expansion of natural gas service in the state, Maine statute permits the PUC to adopt alternative ratemaking mechanisms for gas LDCs and infrastructure investment is reflected in rates on a timely basis under these frameworks. The statute has encouraged the expansion of gas service to areas that previously had no natural gas utility. In 2012, the "Act to Expand the Availability of Natural Gas to Maine Residents" was enacted, authorizing the Finance Authority of Maine to issue bonds to support the expansion of natural gas infrastructure in the state.

The state's largest LDC, Unitil Corp. subsidiary Northern Utilities, has an ongoing Cast Iron and Unprotected Steel replacement program that involves a long-term plan, regular reporting, and a cost recovery mechanism. Northern Utilities' targeted infrastructure replacement adjustment (TIRA) allows the company, subject to certain performance metrics, to receive annual rate increases to recover the costs of its program. The TIRA, which was approved for a four-year period beginning in 2013, is to provide for recovery of the company's investment in targeted operational safety-related infrastructure and upgrade projects. The rate adjustment mechanism has a cap equal to 4% of delivery revenues.

MARYLAND--The PSC does not currently require resource plans to be filed periodically by the jurisdictional gas utilities. Except under certain circumstances (discussed below), gas infrastructure replacement and expansion investment is addressed through the rate case process, once the projects are completed. Typically, if a gas company is expecting to make a large investment, such as for gas transmission or gas distribution service expansion they inform the Commission of the expected investment and expenditures. The Commission may docket a proceeding to investigate the proposal or direct the company to submit the proposal as part of a base rate proceeding. Once the project is completed, the costs may be included in base rates following a prudence review.

Legislation enacted in 2013, established the Strategic Infrastructure Development and Enhancement (STRIDE) Program. Through this program the utilities may file for PSC review and approval of accelerated long-term plans to replace aging infrastructure (the STRIDE plan). Costs associated with an approved STRIDE plan may be recovered through a rider/surcharge (STRIDE Rider). The STRIDE program provides a measure of guarantee with respect to the pre-approved expenditures, but the Companies have to provide details on expenditures of plant that is replaced, and outside audit proof of these expenditures on an annual basis. The STRIDE Rider incorporates the return parameters utilized in the company's most recent base rate case, and recognizes investment as it is placed into service. The law prohibits any adjustment in the STRIDE Rider that would cause monthly customer bills to rise by more than specific amounts. Any amounts left unrecognized by this provision would be deferred for future recovery. While the plans are reviewed by the PSC up front, prudence reviews are conducted prior to rate recovery. Exelon subsidiary Baltimore Gas & Electric, NiSource subsidiary Columbia Gas of Maryland, and WGL Holdings subsidiary Washington Gas Light have STRIDE Riders in place; Chesapeake Utilities does not.

MASSACHUSETTS--In accordance with 2014 legislation, each of the state's LDCs files with the DPU a plan, called a "Gas System Safety Enhancement Program," (GSEP) to address aging or leaking natural gas infrastructure. Initially, LDCs that seek to participate in the program must file a plan that is designed to remove leak-prone cast iron and unprotected steel piping from the LDC's system over a 20-year period. Participating LDCs must file by each Oct. 1 a list of projects the utility plans to complete during the upcoming construction season, as well as proposed adjustments to distribution rates effective May 1 of the following year that will allow for recovery of program-related costs. The law specifies the criteria that the DPU must apply during its evaluation of the LDC's plan and, if the plan meets those criteria, the Department must approve the plan and the adjusted distribution rates. On or before May 1 of each year during an LDC's program, the LDC must file final documentation for projects completed during the prior year to demonstrate substantial compliance with its plan in effect for that year and that project costs were reasonably and prudently incurred. The LDC's May 1 filing reconciles the estimated costs that were approved for recovery to the actual costs incurred during the year, and adjustments to distribution rates (for recovery or refund) are made accordingly.

The ROE authorized in the company's most recent rate case is to be utilized in its GSEP rider. Annual changes in the revenue requirement eligible for recovery may not exceed 1.5% of the company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers. Any revenue requirement approved by the DPU in excess of the cap may be deferred for recovery in the following year. The following utilities have GSEP rate mechanisms in place: UIL Holdings subsidiary Berkshire Gas; National Grid subsidiaries Boston Gas and Colonial Gas; Algonquin Power & Utilities subsidiary Liberty Utilities (New England Gas); NiSource subsidiary Bay State Gas; Eversource Energy subsidiary NSTAR Gas; and, Unitil Corp. subsidiary Fitchburg Gas & Electric. Previously, some of the state's gas utilities used targeted infrastructure replacement mechanisms.

MICHIGAN--There is no formal, periodic integrated resource planning process in place in Michigan. DTE Gas (DTE-G) uses an Infrastructure Recovery Mechanism (IRM) through which the company collects a return of, and on, the costs associated with a planned $387 million capital investment in the company's meter move-out (MMO), accelerated main replacement (MR), and pipeline integrity (PI) programs. The IRM surcharge is adjusted each July 1 to reflect incremental costs incurred under the program. DTE-G's capital spending levels under the IRM are to be reconciled annually. Investment made under the IRM is authorized the company's currently authorized return parameters. If DTE-G were to files a base rate case during the five-year period (2013 to 2017) the IRM surcharge is to be in effect, the surcharge would be suspended when new rates are set by the PSC in that case and all investment made as part of the IRM would be rolled into rate base and recovered prospectively through base rates. As part of the rate case, DTE-G would propose an updated IRM to address recovery over the subsequent five years of future infrastructure investment.

SEMCO Energy has an Expanded Main Replacement Program in place, which allows the company to spend $8.8 million annually above the expenditures included in base rates, to replace high risk mains. The company is recovering the costs via a surcharge, through 2017, that utilizes the company's currently authorized return parameters. CMS Energy subsidiary Consumers Energy and WEC Energy Group subsidiary Michigan Gas Utilities recover infrastructure investment through the base-rate-case process.

MINNESOTA--The LDCs are not required to file resource plans with the PUC. State law permits the gas utilities to file for PUC approval to recover costs to improve safety and reliability through a gas utility infrastructure cost (GUIC) rider. Costs eligible for recovery include those related to pipeline assessment, as well as deferred costs from a utility's existing sewer separation and pipeline integrity management programs. Sewer separation costs result from sewer line inspections and the redirection of gas pipes in the event their paths are in conflict. The ROE to be utilized in these proceedings is the return authorized the company in its most recent base rate proceeding. Xcel Energy subsidiary Northern States Power-Minnesota has a GUIC rider in place, while CenterPoint Energy subsidiary CenterPoint Energy Resources and WEC Energy Group subsidiary Minnesota Energy Resources do not.

MISSISSIPPI--The LDCs are not required to file resource plans with the PSC. Atmos Energy has a formula rate plan mechanism in place in Mississippi, through which it recovers the costs of its infrastructure upgrades on a timely basis.

MISSOURI--The LDCs are not required to file resource plans with the PSC. Generic infrastructure investments are addressed in the context of base rate proceedings. State law permits the PSC to authorize the use of infrastructure system replacement surcharges (ISRS) for the state's LDCs. ISRS-eligible investments must: be considered "used and useful"; not have been included in the utility's rate base in its most recent base rate case; and, not increase the utility's revenues by connecting to new customers.

ISRS projects do not require PSC pre-approval, but the Commission is to conduct a review of actual project-related expenditures in the context of the related cost-recovery proceedings. The PSC is not permitted to approve ISRS rate changes more frequently than semiannually, and the Commission is required to render ISRS decisions within four months of the utility's initial filing. ISRS rate changes are trued-up, and must reflect the rate-of-return parameters adopted by the PSC in the company's most recent base rate case. However, if the case was resolved via a "black-box settlement" that did not specify these parameters, the Commission is to use the average of the values that had been supported by the company in the case and those that were recommended by the other parties. ISRS balances are rolled into the utility's base rates in its next rate case.

The PSC is not permitted to approve ISRS rate changes for any utility that has not had a base rate case decided within the preceding three years (unless the utility has a rate case pending). Annualized ISRS revenues may not exceed 10% of the utility's base revenue level, as approved in its most recent rate case. ISRS rate changes are not permitted if they are less than 0.5% of the utility's base revenue level, or $1 million, whichever is lower. Laclede Group subsidiaries Laclede Gas and Missouri Gas Energy, Algonquin Power & Utilities subsidiary Liberty Utilities (Midstates Natural Gas), and Ameren Corp. subsidiary Union Electric have ISRS riders in place; Empire District Electric subsidiary Empire District Gas and Summit Natural Gas of Missouri do not.

MONTANA--There are no IRP or pre-approval processes in place in Montana, and none of the LDCs have infrastructure riders in place. We note that in 2011, the PSC approved a request by NorthWestern Corp. for an accounting order allowing the company to defer costs associated with a distribution system infrastructure project that runs through 2017, and amortize such deferrals over five years begging in 2013.

NEBRASKA--While there is no periodic, comprehensive integrated resource planning process in place, the LDCs may apply for PSC approval to implement an infrastructure system replacement cost recovery (ISRCR) rider. Amounts recoverable through the ISRCR rider are, by statute, capped at 10% of a utility's Nebraska-jurisdictional annual base revenue level. Investments that would result in an ISRCR rider charge of less than 0.5% of such a baseline amount, or $1 million, whichever is lower, are to be excluded from recovery through the rider. ISRCR rider rate changes may not be requested more frequently than every 12 months.

SourceGas Distribution and Black Hills Corp. subsidiary Black Hills/Nebraska Gas Utility currently utilize such a rider; NorthWestern Corp. does not. In addition, SourceGas Distribution uses a forward-looking system safety and integrity rider that does not include a cap.

NEVADA--The state's LDCs are permitted to seek PUC approval to replace certain infrastructure (e.g., some early plastic pipe and early vintage steel pipe) at the distribution and transmission level. The utility must file a plan that indicates the project-related costs that would be included in a "balancing account" (rate rider). After five annual rider filings, the LDC must file a general rate case to retain the balancing account approach for any new investments. Once a project is placed into service, the revenue requirement (e.g., deprecation and rate of return) are deferred. By each Oct. 1, the utility must file a proposed rate to recover the costs based upon the replacement projects in-service as of the preceding Aug. 31. The proposed rate is to reflect both the on-going replacement projects' revenue requirement and any deferred revenue requirement that accumulated since the in-service date.

In reviewing the LDCs' proposed plans, the Commission must determine whether the costs incurred to replace its infrastructure are incremental to the amount the utility has traditionally invested to replace these types of facilities. Only the incremental costs can be included in the rate rider. Southwest Gas currently has such a rider in place; Berkshire Hathaway Energy subsidiary Sierra Pacific Power does not.

NEW HAMPSHIRE--Legislation enacted in 2014 (House Bill 1540) modified state law with respect to integrated resource planning. H.B. 1540 requires each natural gas utility to file a least-cost integrated resource plan (IRP) with the PUC within two years of the Commission's final order regarding the utility's prior plan, and in all cases within five years of the filing date of the prior plan. H.B. 1540 clarified the biennial filing requirements and extended them to include gas local distribution companies. In deciding whether or not to approve the utility's plan, the PUC is to consider "potential environmental, economic, and health-related impacts of each proposed option. The law indicates that "the commission's approval of a utility's plan shall not be deemed a pre-approval of any actions taken or proposed by the utility in implementing the plan." The related costs are recovered in base rates. In addition, a cast iron/bare steel rate adjustment mechanism is in effect for Liberty Utilities (EnergyNorth Natural Gas) that allows for expedited recovery of these investments. No such plan is in place for Unitil Corp. subsidiary Northern Utilities.

NEW JERSEY--While by law, the Governor periodically develops and releases an Energy Master Plan for the state, there is no company-specific IRP process for gas LDCs in New Jersey. Except under certain circumstances (discussed below), gas infrastructure replacement and expansion investment is addressed through the rate case process, once the projects are largely completed (New Jersey uses test years that are partially forecasted when a case is filed).

During 2009 through 2011, the BPU approved economic stimulus programs proposed by the electric and gas utilities at the Board's request. The programs provided for the acceleration of various infrastructure development projects. The companies were permitted to recover a specified level of costs (including a return on investment) associated with these programs, on an expedited basis, outside of a base rate case. These riders were in place for a limited time, with the related revenue requirement rolled into base rates in subsequent rate cases.

Following 2012's Hurricane Sandy, the BPU reviewed and approved long-term infrastructure resiliency plans, including the cost estimates for the programs and associated cost recovery mechanisms. Such plans were approved for New Jersey Resources Corp. subsidiary New Jersey Natural Gas (NJNG) (Reinvestment in System Enhancement Program), AGL Resources subsidiary Pivotal Utility Holdings (PUH) (Natural Gas Distribution Utility Reinforcement Effort), Public Service Enterprise Group subsidiary Public Service Electric and Gas (PSE&G) (Energy Strong), and South Jersey Industries subsidiary South Jersey Gas (SJG) (the Storm Hardening and Reliability Program). It is our understanding that only PSE&G and NJNG are recovering the related costs through riders. The ROEs used in the riders were determined at the time the mechanisms were approved. For PUH and SJG, recovery is to be addressed in base rate case proceedings. While the specific programs involved in these mechanisms and related planned spending levels are approved up-front, the actual spending levels under the plans are subject to after-the-fact prudence review.

NEW MEXICO--The state has an IRP process in place; however, projects are not subject to PRC pre-approval and the IRP process does not guarantee cost recovery. The IRP rules require TECO Energy subsidiary New Mexico Gas (NMG) to file, every four years, a four-to-10-year IRP plan with the PRC. Infrastructure development projects require a certificate of convenience and necessity (CCN) before construction can begin. Estimated project costs are often put forth during the CCN process, but actual expenditures are subject to after-the-fact prudence reviews. NMG recovers prudent investment through base rate cases.

NEW YORK--There are no comprehensive resource planning guidelines in place. However, each LDC's "rate plan" includes individual reporting requirements. For example, in some rate plans, the reporting requirement specifies that the company is to submit semi-annual reports to the PUC Staff detailing leak-prone pipe (LPP) removal mileage, main locations and costs. There are additional reporting requirements, unique to each LDC, that require the company to file an LPP prioritization summary identifying proposed projects and estimates of costs. There are LPP replacement metrics included in the LDCs' rate plans, with different targets applied to each company. If the company does not meet the specified target, it incurs a negative revenue adjustment, either in terms of a specified dollar amount, or specified number of basis points that would be calculated into a dollar amount.

With respect to cost recovery, besides what is projected and included in each company's rate plan, for replacement of LPP infrastructure, there is no certainty of cost recovery for incremental infrastructure costs incurred. To obtain rate recovery of incremental costs, the company would need to file for a change in rates or file a deferral request. The current method of recovery for National Grid subsidiaries Brooklyn Union Gas and Niagara Mohawk, Fortis subsidiary Central Hudson Gas & Electric, Consolidated Edison subsidiaries Consolidated Edison of New York and Orange & Rockland Utilities, National Fuel Gas subsidiary National Fuel Gas Distribution, Iberdrola subsidiaries New York State Electric and Gas and Rochester Gas & Electric is through a traditional rate case. No additional cost recovery is allowed through an automatic rider or surcharge mechanism. However, the PSC recently approved a surcharge mechanism for KeySpan Gas East (KGE), for a 21-month term, to support the company's LPP replacement program. The ROEs applied to the companies' investments reflect the allowed ROE in the company's most recent rate case. However, for KGE, a new ROE was computed and is to apply to the company's surcharge mechanism.

The PSC recently initiated an investigation to consider implementation of a mechanism for other LDCs to recover their incremental costs associated with the accelerated replacement of LPP infrastructure (see the RRA article dated 4/24/15). Also, a generic proceeding is pending into expanding the availability of natural gas service.

NORTH CAROLINA--The LDCs are not required to file resource plans with the NCUC. Piedmont Natural Gas (PNY) utilizes an Integrity Management Rider (IMR) to track and recover prudently incurred capital investments and associated costs incurred to comply with federal pipeline safety and integrity requirements outside of a general rate case. IMR filings occur annually, each November or December, to reflect costs incurred through the previous October, and the revised rates are to become effective the following February. The return and capital structure parameters utilized in the IMR filings are those authorized in the company's most recent base rate case. The company's capital investments and associated costs are subject to review and a determination of reasonableness and prudence in PNY's annual IMR adjustment proceedings or in its next general rate case. No IMR-like mechanism is in place for SCANA subsidiary Public Service of North Carolina.

NORTH DAKOTA--There are no IRP or pre-approval processes in place for gas utilities in the state, and none of the LDCs, namely MDU Resources Group and Xcel Energy subsidiary Northern States Power-Minnesota, have infrastructure riders in place.

OHIO--Routine infrastructure investments are addressed in the context of base rate proceedings. The LDCs' infrastructure replacement programs were initially approved in base rate proceedings, and updated in subsequent filings that established the scope of the work to take place and the annual ratepayer impact. The LDCs, namely NiSource subsidiary Columbia Gas of Ohio, Dominion Resources subsidiary East Ohio Gas, Duke Energy subsidiary Duke Energy Ohio, and Vectren subsidiary Vectren Energy Delivery of Ohio, subsequently make annual rider filings to recover the costs they incur for the previous year.

OKLAHOMA--The state does not have an IRP process in place for the LDCs, nor are there any provisions that require OCC pre-approval of gas-related infrastructure projects. The costs associated with these investments are addressed in the context of performance-based rate proceedings for ONE Gas subsidiary Oklahoma Natural Gas and CenterPoint Energy subsidiary CenterPoint Energy Resources.

OREGON--The state's LDCs, Avista Corp. and Northwest Natural Gas (NWNG), must file IRPs every two years. These plans identify projected growth and the type of energy resources the utility seeks to put in place to serve its customers over the near- and long-term. There is no guarantee of cost recovery, as the PUC merely acknowledges the plan.

State law permits the PUC to create a voluntary emission reduction program for natural gas utilities. The law is intended to incent the LDCs to propose projects to reduce emissions and provide benefits to customers that would not otherwise undertake in the normal course of business. Participants in the PUC's rulemaking process for suggested that additional language be added to the statute to clarify that when the PUC approves a program, it has the authority to determine the appropriate financial mechanisms available to the utility, including cost recovery, recovery of investments, and incentives. In 2015, legislation was enacted that clarifies that the LDCs may receive incentives for projects approved under the voluntary emission reduction program.

NWNG had a System Integrity Program (SIP) mechanism in place to facilitate recovery of the costs associated with the replacement of bare steel, pipeline integrity, and other pipeline safety programs. The SIP mechanism provided for costs to be tracked annually, with recovery through the PGA after the first $4 million of capital costs were incurred by the company; a cost recovery cap also applied to the mechanism. However, the SIP mechanism has been suspended pending the PUC's generic investigation of the recovery of safety-related costs incurred by natural gas utilities.

PENNSYLVANIA--The PUC does not currently require resource plans to be filed periodically by the jurisdictional gas utilities. Except under certain circumstances (discussed below), gas infrastructure replacement and expansion investment is addressed through the rate case process. However, legislation enacted in 2012, allows the PUC to approve automatic adjustment clauses to recognize between rate cases utility investments in certain gas infrastructure projects.

Pennsylvania utilities may file with the PUC for project-specific distribution system improvement charges (DSICs), provided that the utility has filed a general base rate case with the PUC within five years prior to the DSIC filing. Utilities must submit long-term infrastructure plans, which the PUC is required to review at least once every five years. Automatic rate changes may be implemented on a quarterly basis under an approved DSIC, subject to a cap of 5% of distribution base rate revenue annually and to annual audits to identify and reconcile any over- or under-recoveries. Due to the long-term planning aspect, the program provides some measure of assurance regarding cost recovery (i.e., the PUC is unlikely to find that initiating a particular project was imprudent); however, amounts expended are subject to after-the-fact prudence reviews. The ROE used to set the revenue requirement for the DSIC is that approved in the company's last base rate case, and there are no incentive provisions. NiSource subsidiary Columbia Gas of Pennsylvania, SteelRiver Infrastructure Partners subsidiaries Equitable Gas and Peoples Natural Gas have DSICs in place. National Fuel Gas Company subsidiary National Fuel Gas Distribution, Exelon subsidiary PECO Energy, and UGI Corp. subsidiaries UGI Central Penn Gas, UGI Penn Natural Gas, and UGI Utilities do not.

RHODE ISLAND--State law requires the state's only major LDC, National Grid subsidiary Narragansett Electric, to file an annual infrastructure, safety and reliability plan (ISR). The company is permitted to use an annually adjusted rate mechanism for recovery of the investments the company intends to make pursuant to a pre-approved budget. Between base rate cases, a reconciling factor is developed to allow the company to recover a return on the infrastructure placed in service in any given year. The authorized ROE to be used is the equity return approved in the company's most recent rate case.

SOUTH CAROLINA--The LDCs are not required to file comprehensive resource plans with the PSC. No special riders or clauses are in place to facilitate recovery of main/pipeline replacement costs by the state's two major gas utilities, SCANA subsidiary South Carolina Electric & Gas and Piedmont Natural Gas. However, state law provides for natural gas utilities to be subject to annual rate adjustments if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. Any rate adjustment would be based on the last authorized ROE. Thus, the costs associated with any pipeline/main replacement expenditures effectively are recovered through this mechanism. The gas utilities must request any rate change by June 15 of each year in conjunction with their March 31 quarterly surveillance filings, and a written PSC order must be issued by October 15. Prudence reviews take place in the context of the companies' annual rate adjustment proceedings.

SOUTH DAKOTA--NorthWestern Corp. files an IRP with the PUC for informational purposes, but there are no formal IRP or pre-approval processes in place. The company does not have an infrastructure rider in place.

TENNESSEE--The utilities are not required to file comprehensive resource plans with the TRA; however, certain utilities file information that is considered the equivalent of a resource plan. Atmos Energy's recently approved formula rate plan adjusts rates annually and addresses recovery of the costs associated with its infrastructure replacement program. Piedmont Natural Gas has an integrity management rider in place through which the company recovers, between base rate proceedings, the costs associated with system integrity projects. No such mechanism is in place for AGL Resources subsidiary Chattanooga Gas.

TEXAS--The framework for gas utilities in Texas is somewhat unique in that the municipalities within which the companies operate have original jurisdiction over the distribution rates charged by the LDCs. Rate cases are generally conducted on a municipality-specific basis, and regulatory frameworks can vary from city to city. The RRC has appellate jurisdiction with respect to rates approved by the municipalities, and has original jurisdiction to set rates for customers that operate in unincorporated areas of the state. Neither the Cities nor the RRC currently require resource plans to be filed periodically by the gas utilities. Prudence reviews of utility infrastructure investments generally occur as the projects are placed into service and the utility seeks rate recognition.

In certain areas of the state, the municipalities have approved rider mechanisms that permit recovery of certain gas infrastructure investment through a rider, between rate cases; in others annual rate review mechanisms (RRMs) are used (similar to formula-based ratemaking) where base rate adjustments occur annually. CenterPoint Energy subsidiary CenterPoint Energy Resources has a Gas Reliability Infrastructure Program (GRIP) in place for is Houston and South Texas divisions. A similar mechanism is in place for most of the cities in Atmos Energy's Mid-Tex and West Texas Divisions. Atmos' operations in the City of Dallas and its environs, certain other cities that are part of the Mid-Tex Division, and certain cities that are part of Atmos' West Texas division are subject to RRMs, while others have GRIP mechanisms in place. ONE Gas subsidiary Texas Gas Service has an RRM in place in certain cities.

UTAH--Questar Corp. subsidiary Questar Gas, the state's only investor-owned gas utility, files an IRP on an annual basis. There is a pre-approval process that is available to the company, but it has been rarely used. An infrastructure replacement adjustment (IRA) mechanism is in place for Questar, through which it recovers, between rate cases, the costs associated with the replacement of certain natural gas feeder lines. The IRA mechanism's rates are adjusted at least annually, and cannot exceed an annual budget cap of $65 million.

VERMONT--Pursuant to state law, all regulated utilities in Vermont are required to submit least-cost integrated plans every three years. Cost recovery for Vermont Gas Systems' aging infrastructure replacement projects is accomplished as part of a rate review conducted through the company's alternate regulation plan (ARP). In 2011, the PSB approved the "Vermont System Expansion and Reliability Fund" that permits Vermont Gas Systems to utilize funds (for expansion projects) that would otherwise be passed through to ratepayers from anticipated rate reductions in its purchased gas adjustment.

VIRGINIA--The SCC does not currently require comprehensive resource plans to be filed periodically by the jurisdictional gas utilities. Except under certain circumstances (discussed below), gas infrastructure replacement and expansion investment is addressed through the rate case process. Legislation enacted in 2008, known as the CARE (Conservation and Ratemaking Efficiency) Act, allows gas utilities to seek SCC approval of energy conservation programs and expedited rate treatment for the related costs/investment. Columbia Gas of Virginia has an active program under this statute. WGL Holdings subsidiary Washington Gas Light and AGL Resources subsidiary Virginia Natural Gas elected not to pursue this.

Legislation enacted in 2010, known as Steps to Advance Virginia's Energy Plan (SAVE Act), authorizes the SCC to review and approve a natural gas utility's plans to invest in reliability related main replacement projects. Costs associated with the investments may be recovered through a rider between rate cases. There is no cost cap, but program costs are subject to a prudence review as recovery is sought. Atmos Energy, NiSource subsidiary Columbia Gas of Virginia, VNG, and WGL have SAVE programs in place. Both the CARE and SAVE riders utilize the return parameters set in the company's most recent rate case. Legislation enacted in 2012, established guidelines for SCC reviews of proposed gas distribution infrastructure expansion projects to serve additional customers. The legislation requires a number of criteria to be met for a project to be approved, including expected opportunities for local economic development benefits.

WASHINGTON--Each LDC must file an integrated resource plan every two years; these plans do not give any particular assurance of cost recovery. Cost recovery for pipe replacement investments can occur through a base rate case or a cost recovery mechanism (CRM). If a CRM is used, the authorized rate of return from the company's most recent rate case is to be used. Only the actual pipe replacement costs may be recovered. In addition, if a CRM is used, a rate case must be filed within four years of its implementation. Currently, Puget Sound Energy and MDU Resources subsidiary Cascade Natural Gas have approved CRMs in effect; Avista Corp. does not.

WEST VIRGINIA--The state has no gas IRP process, nor are there any provisions for pre-approval or expedited treatment of specific projects or programs. Gas infrastructure investment for Dominion Resources subsidiary Hope Gas and Mountaineer Gas is addressed in base rate cases and is subject to after-the-fact prudence reviews.

WISCONSIN--The LDCs are not required to file resource plans with the PSC. Except for very small projects, gas infrastructure projects in Wisconsin require the utilities to file with the PSC for a certificate of authority (COA). The COA issued by the PSC contains a cost estimate, and if the project's actual costs are exceeded by more than 10%, the utility must notify the PSC. No riders or adjustment clauses are in place in Wisconsin to facilitate the recovery of main/pipeline replacement costs by the state's gas utilities. However, since the state's utilities typically file general rate cases annually (or occasionally once every two years), and the PSC allows for rate recognition of at least a portion of construction work in progress, rate recovery of these costs occurs in a timely manner through the general rate case process for MGE Energy subsidiary Madison Gas & Electric, Xcel Energy subsidiary Northern States Power-Wisconsin, WEC Energy Group subsidiaries Wisconsin Electric Power and Wisconsin Gas, Alliant Energy subsidiary Wisconsin Power & Light, and WEC Energy Group subsidiary Wisconsin Public Service.

WYOMING--Questar Corp. subsidiary Questar Gas is the only LDC that submits an IRP to the PSC, and it is purely for informational purposes. No pre-approval process exists in the state, and none of the LDCs, namely Questar Gas, Black Hills Corp. subsidiary Cheyenne Light Fuel & Power and SourceGas LLC subsidiary SourceGas Distribution, have infrastructure riders in place.