OTS Statement No. 1
Witness: Robert Plonski

11/19/08

HBG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Direct Testimony

of

Robert Plonski

Office of Trial Staff

Concerning:

RATE OF RETURN

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Robert Plonski. My business address is P.O. Box 3265, Harrisburg, Pa. 17105-3265.

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

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff as an expert witness.

Q. **PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS?**

A. OTS was established by the legislature and is responsible for protecting the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. **WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I have prepared this information in Appendix A supplementing my direct testimony.

SUBJECT OF TESTIMONY

Q. PLEASE IDENTIFY THE ISSUES THAT ARE ADDRESSED IN YOUR TESTIMONY.

A. The issues addressed in my direct testimony concern rate of return, including capital structure, the cost rate of short-term debt, the cost of common equity, and the overall fair rate of return for Equitable Gas Company (Equitable or Company).

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT THAT SUPPORTS YOUR RECOMMENDATIONS WITH RESPECT TO A FAIR RATE OF RETURN?

A. Yes. OTS Exhibit No. 1 presents the analyses that I have conducted regarding rate of return.

BACKGROUND DISCUSSION

Q. HOW DOES THE RATE OF RETURN COMPONENT FIT WITHIN THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula is as follows:

$$RR = E + D + T + (V-d) \times R$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expense
D	=	Depreciation Expense

T	=	Taxes
V	=	Gross Rate Base
d	=	Accrued Depreciation
R	=	Overall Rate of Return

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

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

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

The <u>Bluefield Water Works</u> and <u>Hope Natural Gas</u> cases of 1923 and 1944, respectively (cited below), set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

<u>Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia</u>, 262 U.S. 679, 692-93 (1923).

> It is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with risks on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

<u>FPC v. Hope Natural Gas Co</u>., 320 U.S. 591, 603 (1944).

While interpretations of these excerpted citations may vary somewhat, they provide general guidelines for the regulator to determine a fair rate of return.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU CALCULATED YOUR OVERALL RATE OF RETURN?

A. Yes. The overall rate of return in this rate proceeding is calculated using the weighted average cost of capital method, which is the interaction of the following components: the percentage of long-term debt, the percentage of short-term debt, the percentage of common equity, the cost of long-term debt, the cost rate of short-term debt and the cost rate of common equity. First, it is necessary to determine the proportion of each type of capital (referred to as the capital structure) which has financed the rate base and assign the appropriate cost rate to each. The cost rate of debt is fixed and can be computed accurately. The cost rate of common equity is not fixed and is much more difficult to measure.

The overall rate of return is then calculated using the proportions of capital and cost rates for each type of capital. OTS Exhibit No. 1, Schedule 1, demonstrates the interaction of the capital structure and the cost rates of each type of capital. By multiplying each capital component's capital ratio by its associated cost rate, a weighted cost rate is derived for each capital component. The overall rate of return is the sum of weighted cost rates.

COMPANY POSITION

Q. WHAT IS THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE?

A. The Company recommended the following rate of return:

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	40.90	6.39	2.61
Short-Term Debt	9.10	3.26	0.30
Common Equity	50.00	11.95	5.98
Total	100.00		8.89

Source: Equitable Statement No. 5, page 2.

Basis

Q. WHAT IS THE BASIS FOR THE COST RATE OF LONG-TERM DEBT CLAIMED BY EQUITABLE?

A. In direct testimony on page 19, Mr. Hanley states that he utilized the composite debt cost rates of the proxy group of gas companies to calculate a beginning rate of 6.20%. From that starting point, Mr. Hanley added a nineteen basis point adjustment (0.19%), accounting for issuance costs, to arrive at a long term debt cost rate of 6.39%. The calculation is presented on the Company's Schedule 5, page 1.

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

A. The basis for the cost rate of short-term debt is presented on pages 19 and 20 of Mr. Hanley's direct testimony. Mr. Hanley states that a short-term cost rate is not available for his proxy group. Because of this, Mr. Hanley developed a cost rate of short-term debt based on the LIBOR rate from Blue Chip Financial Forecasts. Mr. Hanley calculated a prospective LIBOR rate of 2.26% utilizing the average consensus for the month ending in the second quarter of 2008 and ending with the third quarter of 2009. From that starting point, the witness for the Company added a one hundred basis point adjustment to achieve his final cost rate of 3.26%. The reason given for the adjustment is that it allows for a forward looking cost rate for Equitable.

Q. WHAT IS THE BASIS FOR EQUITABLE'S COST RATE OF COMMON EQUITY CLAIM?

A. On page 6 of his direct testimony, Mr. Hanley states that he employed four models to develop a cost of equity recommendation. The methods used by Mr. Hanley were the Discounted Cash Flow (DCF), Risk Premium (RP), Capital Asset Pricing Model (CAPM), and Comparable Earnings (CE) methods. To derive his cost of equity recommendation, Mr. Hanley evaluated the cost rates of a proxy group for gas utilities. Mr. Hanley determined that the cost of common equity for the gas distribution industry is 11.0%. To the industry average cost of equity, Mr. Hanley added a size adjustment of twenty-five (25) basis points, an adjustment of twenty (20) basis points due to a perceived lack of protection in rate design and an adjustment of fifty (50) basis points due to competition.

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

A. Mr. Hanley, in direct testimony, states that Equitable's capital structure for the test year ended December 31, 2008 is meaningless due to the Company being a division of Equitable Resources and as such is recommending a hypothetical capital structure of 50.0% debt and 50.0% equity. On page 17 of Mr. Hanley's direct testimony, he states that the above referenced hypothetical capital structure for the Company was determined by estimating Equitable's bond rating at a Standard and Poor's (S&P) grade of A and an intermediate risk profile. He explains that the total debt to total equity ratio for an A rated utility would be in the range of 35.0% to 50.0%. As such, the allowable equity ratio would be in the 65.0% to 50.0% range. On page 18 of his direct testimony, he states that the total long-term debt was 81.80% of total debt. The figure of 40.90% was achieved by multiplying 50.0% x 81.80%. Mr. Hanley further states his belief that his hypothetical capital structure for the Company is reasonable and conservative.

Q. WHAT IS THE COMPANY'S BASIS FOR THE SHORT-TERM DEBT RATIO OF 9.10%?

A. Mr. Hanley states that the average short-term debt for his proxy group made-up 18.20% of total debt for five quarters beginning in December 2006 and ending in December 2007. Multiplying 18.20% times 50.0% he arrived at a short-term debt ratio of 9.10% for the Company.

OTS POSITION

Elements Disputed

Q. HOW DOES YOUR RECOMMENDATION DIFFER FROM THE COMPANY'S CLAIM?

A. My recommendation differs in four areas: the cost rate of short-term debt; capital structure; the cost rate of common equity; and finally, the overall rate of return. First, I am recommending a cost rate of short-term debt of 2.26% in lieu of the Company's requested 3.26%. Second, I recommend a capital structure for the Company consisting of 41.35% long-term debt, 13.20% short-term debt, and 45.45% common equity instead of Mr. Hanley's proposed hypothetical capital structure of 40.90% long-term debt; 9.10% short-term debt and 50.00% common equity. Third, I recommend a 10.05% cost rate of common equity in lieu of Equitable's requested 11.95% recommendation. Finally, my overall rate of return recommendation is 7.51% instead of Equitable's 8.89%.

Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. The following is a summary of my rate of return recommendation:

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-term Debt	41.35	6.39	2.64
Short-term Debt	13.20	2.26	0.30
Common Equity	45.45	10.05	4.57
Total	100.00		7.51

Source: OTS Exhibit No. 1, Schedule No. 1.

COST OF SHORT-TERM DEBT

Q. WHAT COST RATE OF SHORT-TERM DEBT ARE YOU RECOMMENDING?

A. I am recommending a cost rate of short-term debt of 2.26%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am accepting the Company's figure as presented on page 20, lines 3 – 6, of Equitable Statement No. 5. I will accept the computation of 2.26% before the addition of a one hundred basis point adjustment (1.00%) added to the original cost rate.

Q. WHY ARE YOU REJECTING THE COMPANY'S ONE HUNDRED BASIS POINT (1.00%) ADJUSTMENT TO THE COST RATE OF SHORT-TERM DEBT?

A. The Company has added an unwarranted one hundred basis point to the initial calculation of the cost rate of short-term debt. Mr. Hanley has provided no evidence to support his assertion that the adjustment provides a forward looking cost rate of short-term debt. I specifically asked Mr. Hanley to provide all the financial and/or academic articles that supports his claim that his proposed adjustment results in a forward looking cost rate of short-term debt (OTS-RR-16-D). His response to that data request indicated that his calculation was based on Company supplied information (OTS Exhibit No. 1, Schedule No. 13). However, Mr. Hanley did not provide any documentation that supported that claim.

CAPITAL STRUCTURE

Basis for Determining a Capital Structure

Q. WHAT CAPITAL STRUCTURE ARE YOU RECOMMENDING?

A. I am recommending a hypothetical capital structure of 41.35% long-term debt, 13.20% short-term debt, and 45.45% common equity.

Q. WHY ARE YOU RECOMMENDING A HYPOTHETICAL CAPITAL STRUCTURE IN THIS INSTANCE?

A. I am recommending a hypothetical capital structure because Equitable Resources', Equitable Gas' parent company, equity ratio of 53.49% equity is not representative of the gas distribution industry as presented in my barometer group analysis.

Q. WHY HAVE YOU NOT ELECTED TO USE EQUITABLE GAS' CAPITAL STRUCTURE?

A. The information on the debt to equity ratios for Equitable Gas is unavailable. According to the Company's Exhibit II, Item § 53.53 II-A-2, Sheet 1 of 1, in response to a general interrogatory, the Company states that there is not similar report to the 10Q report presented in Exhibit II. Since data to determine Equitable Gas' capital structure is not available, because Equitable Gas is a division of Equitable Resources, the appropriate action to take in this instance is the utilization of a hypothetical capital structure.

Q. HOW DID YOU DETERMINE THE APPROPRIATE HYPOTHETICAL CAPITAL STRUCTURE?

A. My recommended hypothetical capital structure is based on the long-term debt and short-term debt averages and common equity averages for the companies in my barometer group for 2007 of 41.35% long-term debt, 13.20 short-term debt, and 45.45% equity (OTS Exhibit No. 1, Schedule No. 4, page 4).

In direct testimony, the Company has proposed a hypothetical capital structure of 50.0% total debt and 50.0% equity. This capital structure is a creation of Mr. Hanley based on S&P criteria for an A rated utility. However, his capital structure is not representative of the gas distribution industry sampled by my barometer group.

COST OF COMMON EQUITY

Basis for Determining the Cost of Common Equity

Q. WHAT IS THE BASIS FOR YOUR 10.05% COST OF EQUITY RECOMMENDATION?

A. I used the Discounted Cash Flow (DCF) method applied to a barometer group of local gas distribution companies (LDC) to determine a range of 9.30% - 10.80% as the approximate cost rate of common equity in this proceeding (OTS Exhibit No. 1, Schedule No. 5, pages 1 – 2). To compute the various components of the DCF method, I relied upon historical and forecasted market data for each company in the barometer group. In this proceeding, I have selected the mid-point of the range which is 10.05%.

Barometer Group

Q. WHY HAVE YOU LIMITED YOUR ANALYSIS TO A BAROMETER GROUP IN THIS PROCEEDING?

A. Since the cost of equity capital is set in the marketplace, it is necessary to use market-based data. Since Equitable has no market-based data available, it is necessary and proper to use a barometer group of publicly traded gas companies to determine a cost of equity for the gas distribution industry. While Equitable Resources, the parent of the Company, is a publicly traded company, in this instance it would be inappropriate to use the data for Equitable Resources because only 36.0% of its net income is derived from utility operations.[1]

Q. ARE THERE OTHER REASONS FOR USING BAROMETER GROUPS?

A. Yes. The use of data for one company may be less reliable than using a barometer group because the data for one company may be subject to events which can cause short-term aberrations in the marketplace. The rate of return on common equity for a single company could become distorted in these particular circumstances. The use of barometer group data has the effect of smoothing out any aberrations associated with a single company.

A barometer group cost of equity is also used as a benchmark to satisfy the long established guideline of providing a utility the opportunity to earn a return equal to that of similar risk enterprises.

Q. WHAT CRITERIA DID YOU USE TO SELECT YOUR BAROMETER GROUP?

[1] Source: Value Line On-Line Survey

A. My barometer group consists of all publicly traded LDCs that satisfy the following criteria: (1) have at least two sources of analysts' forecasts of earnings growth; (2) are not the announced subject of an acquisition; (3) have a customer base of more than 300,000; (4) are located in the eastern part of the United States; (5) had a higher percentage of sales associated with utility operations than other segments of the business unit.

Q. WHAT COMPANIES SATISFIED YOUR CRITERIA?

A. The eight companies that met my criteria are listed on Schedule No. 6 of OTS Exhibit No. 1.

<u>Economic Factors</u>

Q. DOES YOUR COST OF EQUITY ANALYSIS TAKE CHANGING BUSINESS AND ECONOMIC CONDITIONS INTO ACCOUNT?

A. Yes. The financial markets take all factors into account when assessing investments. The aggregate risks of an investment are reflected in the stock price per share. The data for the barometer group that I have utilized is market based; therefore, my results have implicitly accounted for all these factors.

Q. WHAT ECONOMIC FACTORS DO YOU CONSIDER IMPORTANT IN YOUR ANALYSIS OF COST OF CAPITAL?

A. I have made comparisons of important economic variables and have examined their impact on gas utilities over the past twenty-six (26) years. Schedule 7 of OTS Exhibit No. 1 presents a historical perspective of the "Aaa" Corporate Bond Yield, the U.S. 10 year Treasury Bond (T-Bond) rate, the prime rate, and the percentage change in the Consumer Price Index (CPI) compared to the average dividend yield of my barometer group. This schedule also presents a sampling of economic experts' quarterly forecasts for 2008 and 2009, and yearly forecasts for the period 2010 to 2019.

Q. IS THERE A RELATIONSHIP BETWEEN DIVIDEND YIELDS OF GAS COMPANIES AND BOND YIELDS?

A. Yes. A comparison of the bond yields and dividend yields in Schedule 7 of OTS Exhibit No. 1 reveals a direct relationship between these two variables. The correlation coefficient of the two arrays is 0.98, which indicates a strong relationship. This high correlation should be expected since all capital costs are extremely competitive. As a result, I believe it's important in determining an appropriate cost rate of common equity to recognize this relationship. Any potential impact related to a projected change in bond yields should be considered in recommending a representative dividend yield for the prospective period.

Q. WHAT HAS BEEN THE HISTORICAL TREND OF PUBLIC UTILITY BOND YIELDS AND THE BAROMETER GROUPS' DIVIDEND YIELDS?

A. The trend in "Aaa" rated bond yields and gas utility dividend yields presented in Schedule 7 has been a steady decline over the past twenty-six (26) years. Since 1982, "Aaa" rated corporate bond yields have decreased from 13.79% to 5.56% through 2007, or by 823 basis points. From 1982 to 2007, the eight company barometer group's dividend yield declined from an average of 10.96% to 3.61%, resulting in a decline of 735 basis points.

Q. WHAT IS THE OUTLOOK FOR INTEREST RATES IN RELATION TO THE FORECASTED INFLATION RATE?

A. Schedule 7 also presents short-term and long-term forecasts published by Blue Chip Financial Forecasts. Over the next six quarters, forecasting professionals are expecting 10 year T-Bond yields to be between 4.0% and 4.6%, and forecasted inflation at 5.7%, with short-term expectations (4th quarter 2009) of 2.4%. As a result, the real rate of interest[2] is expected to be in the -1.7% to 2.2% range for this period.

Forecasting professionals are also expecting interest rates on long-term "Aaa" rated corporate bonds to increase from 5.7% in the third quarter of 2008 to 6.1% by the fourth quarter of 2009. These forecasts are dependent upon forecasters' belief that investors can expect an upturn in the economy with the

[2] The real rate of interest is the nominal rate of interest minus the inflation rate.

growth in real GDP 1.0% in the third quarter of 2008 increasing to an average of 2.6% by the fourth quarter of 2009[3].

Investors' expectations are, however, continually changing and influenced by Federal Reserve policy. The Federal Reserve's tight monetary policy of recent years has done much to alleviate inflationary fear. If the Federal Reserve continues to maintain its current anti-inflationary bias in monetary policy and manages to attain its interest rate and monetary targets, investors' inflationary expectations will continue to decrease, resulting in lower and more stable interest rates.

Q. WHAT EVIDENCE EXISTS THAT INTEREST RATES WILL CONTINUE TO REMAIN FAIRLY STABLE?

A. Schedule 7 of OTS Exhibit No. 1 further presents extended forecasts for the various interest rates presented. Expectations are for stable to slightly increasing interest rates and steady inflation expectations through the year 2019. However, the slight increase is to a level that has been experienced during the past ten years. As a result, this increase should not be construed as a long term trend.

[3] Blue Chip Financial Forecasts, September 1, 2008.

Discounted Cash Flow Analysis (DCF)

Q. WILL YOU PLEASE EXPLAIN YOUR DCF METHOD OF ANALYSIS?

A. Yes. My analysis employs the standard discrete DCF model,

$$k = D_1 / P_0 + g.$$

Where:

k = the cost of equity

D_1 = the dividend expected during the year

P_0 = the current price of the stock

g = the expected growth rate of dividends.

When a forecast of D_1/P_0 is not available, D_0/P_0 (the current dividend divided by the current price) must be adjusted by ½ the expected growth rate[4] in order to account for changes in the dividend rate in period 1.

Q. PLEASE STATE THE RESULTS OF YOUR DISCOUNTED CASH FLOW (DCF) ANALYSIS.

A. The following table summarizes the results of my DCF analysis:

	Range	Average
Eight Company Barometer Gp.	9.30% - 10.80%	10.05%

Source: OTS Exhibit No. 1, Schedule No. 5, Column 3, pages 1 and 2.

[4] The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain or a projection of the next period dividend is unavailable. It could occur next month or the twelfth month. On average it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by 1/2 the expected growth rate is appropriate.

Dividend Yield

Q. **PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS THAT WERE USED IN YOUR DCF ANALYSIS?**

A. A representative dividend yield must be calculated over a time frame that avoids the problems of short-term aberrations and "stale" data series. For purposes of my DCF analysis, I placed equal emphasis on the most recent spot price and 52 week average price from YahooFinance.com August 5, 2008. The dividend for the year ahead period was taken from Value Line On-line Ratings and Reports, August 5, 2008. The following table summarizes my dividend yield computations for the barometer group:

	Dividend Yields (Adjusted)		
	Spot 8/5/08 Range (%)	52-week Average Range (%)	Average Range (%)
Eight Company Barometer Gp.	4.06	4.00	4.03

Source: OTS Exhibit No. 1, Schedule 5, Column 1, pages 1 and 2.

Growth Rate

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

A. To arrive at a representative dividend growth rate, I surveyed several series of both projected growth rates and historical growth rates. I primarily used forecasted growth rates because of the strong historical showing. These growth rates are presented in OTS Exhibit No. 1, Schedule 6. My growth rate estimates are based on a survey of established forecasting entities, including Value Line, Yahoo Finance, MSN Money and Morning-Star.

Q. WHY HAVE YOU CHOSEN ANALYSTS' GROWTH RATE FORECASTS IN YOUR DETERMINATION OF AN OVERALL GROWTH RATE?

A. Analyst's estimates are an attempt to forecast future cash flows; whereas, historical growth rates are backward looking. For that reason, I believe analyst estimates are a good indicator of possible future expectations. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings from which they are calculated. If the base earnings are abnormally low (high), the growth rates from which they are calculated will likely be distorted and the earnings growth rates will most likely be overstated (understated) and unsustainable.

Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR THE EIGHT COMPANY BAROMETER GROUP?

A. I conclude that investors could reasonably expect to achieve a growth rate in the range of 5.3% to 6.8% for the barometer group.

Q. HOW DID YOU ARRIVE AT YOUR GROWTH RATE RANGE FOR YOUR BAROMETER GROUP?

A. The low-end of the range was attained by utilizing the growth rate estimates presented in the Value Line Investment Survey as of August 5, 2008. The average five year projected growth rate from Value Line was 5.3%. The high-end was attained by using the five year growth rate estimates from MSN Money. The average growth rate for the companies contained within my barometer group for the same time period is 6.8%, according to MSN Money.

Q. WHAT COST RATE OF COMMON EQUITY IS INDICATED FROM THE RESULTS OF YOUR DCF ANALYSIS?

A. Given these representative dividend yields and my recommended growth rate, I calculated the DCF return with the results presented on OTS Exhibit No. 1, Schedule 5, Column 3, pages 1 and 2. The results of this calculation indicate that the cost rate of common equity for the gas distribution industry is in the range of 9.30% to 10.80%. In the case of Equitable, I recommend the mid-point of the range of 10.05%.

<u>CAPM Analysis</u>

Q. HAVE YOU PERFORMED ANY OTHER ANALYSES TO DETERMINE THE APPROPRIATE COST OF EQUITY?

A. Yes. I performed a Capital Asset Pricing Model (CAPM) analysis.

Q. WHY DID YOU CONDUCT A CAPM ANALYSIS?

A. I conducted a CAPM analysis as a check of the DCF results by a second method; it is my opinion that the CAPM is an appropriate method for that purpose.

Q. PLEASE EXPLAIN THE CAPM ANALYSIS?

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

$R = R_f + \text{beta} \times (K_m - R_f)$

Where:

R = *the expected return rate on a security;*

R_f = the rate of a "risk-free" investment, i.e. 90 day T-bill, 10yr. T-bond, 20yr. T-bond, 30yr. T-bond;

K_m = the return rate of the appropriate asset class, i.e. historic return of S&P 500.

Beta = the systematic risk of the chosen asset class.

The Capital Asset Pricing Model hypothesizes that the expected return on a security is determined by a risk free rate of return plus a risk premium which is proportionate to non-diversifiable risk. Non-diversifiable risk is also known as systematic or market risk.

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

A. I have chosen the yield on the 10-year Treasury Bond as my risk free (R_f) rate of return. If one chooses a longer horizon for the risk free rate, the return also includes a premium associated with market risk and the risk of unexpected inflation. Shorter rates are more sensitive to Fed fund rate changes; as a result they are more volatile than longer term rates. In an effort to balance out the inherent risks between short-term T-Bills and long-term T-bonds, I have chosen the projected 10-year T-Bond rate. The projected rate for the 10 year T-Bond through 2019 is 5.30% (OTS Exhibit No. 1, Schedule No. 7). I have chosen this as my risk free rate.

Q. WHAT HAVE YOU CHOSEN AS YOUR EXPECTED MARKET RETURN?

A. I have chosen the historic rate of return for the S&P 500 of 9.81% for the period of 1928 to 2007 (OTS Exhibit No. 1, Schedule No. 9, pages 1 – 2).

Q. WHY HAVE YOU CHOSEN THE HISTORIC RATE OF RETURN FOR THE S&P 500 AS THE EXPECTED MARKET RETURN?

A. I have chosen the historical rate of the S&P 500 because it is my professional opinion that an investor cannot expect to earn a rate of return greater than the market (i.e. Dow Jones Average, NASDAQ, and S&P 500). Based on this philosophy, the choice is then limited to which index to chose. Since it is made up of more diversified stocks, than other indexes, I have chosen the historical return for the S&P 500.

Q. HOW DID YOU CALCULATE THE HISTORIC RATE FOR THE S&P 500?

A. I utilized the geometric mean to calculate the historic return for the S & P 500.

Q. WHY HAVE YOU CHOSEN THE GEOMETRIC MEAN RATHER THAN THE ARITHMETIC MEAN?

A. The geometric mean has advantages over the arithmetic mean by being less affected by extreme values in skewed data and is an appropriate measure for data that involve ratios, such as percentages.

A simple example proves this point. Suppose a hypothetical investor has $100 to invest over a two-year period. The first year the investor earns a 100.0% return so that his ending wealth at the end of the period 1 is $200. The second year the investor has a 50.0% negative return (loses $100) so that his ending wealth at the end of period 2 is $100. The geometric mean for this example is 0.0% (100/100) ^ (1/2), while the arithmetic mean return is 25.0% (100.0% + (-50.0%) / 2). Clearly the investor earned nothing over the two year period, but the arithmetic mean says he earned a yearly return of twenty-five percent (25.0%). This simple example illustrates the inherent bias of using the arithmetic mean to calculate period returns.

Q. IN WHAT DIRECTION DOES THE ARITHMETIC MEAN TEND TO BIAS RESULTS?

A. As clearly pointed out in my previous example, the arithmetic mean will produce results that will be upwardly biased.

Q. HAS THE ACADEMIC LITERATURE COMMENTED ON THIS PHENOMENON?

A. Yes. Marshall Blume stated that "As long as the N exceeds one, this procedure will yield an upward biased estimate." [5]

Q. DOES THE FINANCIAL LITERATURE CONFIRM THIS OPINION?

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[5] Marshall E. Blume, "Unbiased Estimators of Long-Run Expected Rates of Return", Journal of American Statistical Association, September 1974, Vol 69, No. 347

A. Yes. Nancy Jacob in her textbook *Investments* presents the following example:

> Too often the following ill-formed logic is employed by those attempting to sell their financial services: 'During the past 10 years our fund has generated annual returns that have averaged 20 percent. An investor who invests $10,000 with us for 20 years, assuming the same return, could expect to accumulate $383,000 after 20 years.' The statement is wrong because it compounds the average arithmetic return, E(R) = .20 over 20 years rather then the average geometric mean. Actually, if this portfolio was invested in stocks with a standard deviation equal to that of the S&P 500 index, the accumulation of wealth would be more on the order of $220,000. The difference between $220,000 and $383,000, to an investor planning for retirement, needless to say, is substantial.[6]

Q. DO THE TRADE PUBLICATIONS SUCH AS IBBOTSON ASSOCIATES MAKE MENTION OF THE USE THE GEOMETRIC MEAN?

A. Yes, Ibbotson Associates mentions it use.

Q. WHAT DID IBBOTSON ASSOCIATES SAY CONCERNING THE USE OF THE GEOMETRIC MEAN?

A. In 2004, Ibbotson Associates stated the following about the use of the geometric average:

> "The geometric average is more appropriate for reporting past performance, since it represents the compound average return."[7]

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6 Nancy L. Jacob and R. Richardson Pettit, Investments, Irwin, 1988, pp. 126 - 127

7 Source: page 71 of Stocks, Bonds, Bills, and Inflation (2004 Yearbook).

Q. HOW IS BETA DEFINED?

A. Beta is defined as a measure of systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by running a linear regression of a stock's total return against the total return of the overall stock market. When the result of this regression is greater than one (1), the stock is said to have more risk than that of the stock market. When the result of the regression is less than one (1), the stock is said to have less risk than the overall stock market. When the result of the regression is equal to one (1), the stock is said to have the same amount of risk as the overall market.

Q. WHAT BETA HAVE YOU CHOSEN FOR YOUR CAPM ANALYSIS?

A. I have chosen a beta of .88. The average beta for the barometer group is based on the information found on Value Line On-Line service (OTS Exhibit No.1, Schedule No. 10).

Q. WHAT COST RATE OF COMMON EQUITY IS INDICATED FROM THE RESULTS OF YOUR CAPM ANALYSIS?

A. Using the projected rate of the 10 year T-Bond of 5.30%, the historical S&P 500 market rate of 9.81%, and an average beta of the chosen barometer group of .88, the cost of equity result from the CAPM is 9.27% (OTS Exhibit No. 1, Schedule No. 11).

Q. HOW DOES THE RESULTS OF THE CAPM ANALYSIS COMPARE TO THE RESULTS OF THE DCF ANALYSIS?

A. The cost of equity result of 9.27% for my CAPM analysis confirms my recommendation of 10.05% is reasonable.

CRITIQUE OF THE COMPANY'S COST OF CAPITAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR CRITIQUE OF EQUITABLE'S COST OF CAPITAL TESTIMONY.

A. I have five primary areas of disagreement concerning the Company's cost of capital testimony.

- First, the Company's witness has selected a proxy group that is too dissimilar for estimating a cost of equity for Equitable.

- Second, the Company's witness unadjusted cost rate of equity recommendation of 11.0%, is not supported by his own testimony.

- Third, the Company's witness has inflated his DCF analysis by including a lack of protection in rate design adjustment of twenty basis points (0.20%); a size adjustment of twenty-five basis points (0.25%) and a fifty basis adjustment (0.50%) due to perceived competition to his final result.

- Fourth, the Company's witness has incorrectly given consideration to the Risk Premium, CAPM and Comparable Earnings in his recommendation, in addition to his DCF findings.

- Fifth, the Company's witness is incorrect in his assertion that the DCF method is not a stand-alone method.

Q. PLEASE ADDRESS YOUR FIRST AREA OF DISAGREEMENT AND EXPLAIN WHY YOUR BAROMETER GROUP DIFFERS FROM THE COMPANY'S?

A. A barometer group is meant to be an instrument that is composed of companies that have attributes similar to the company that it is estimating for a cost rate of equity. While no group is a perfect representation, by Mr. Hanley's own admission in direct testimony, his group is too dissimilar. Mr. Hanley's selection criteria created a barometer group that is dissimilar to Equitable. This is demonstrated by his chosen group whose market capitalization is 3.3x larger than the market capitalization he has assumed for Equitable. As a result of this difference, Mr. Hanley requests that the ALJ and the Commission grant a higher rate of return because of the Company's small size. This would indicate to me that there is a flaw in the methodology utilized by the Company's witness.

Q. DOES THE ACADEMIC LITERATURE SUPPORT YOUR BELIEF THAT THE SIZE OF A UTILITY SHOULD NOT BE A FACTOR IN THE DETERMINATION OF AN APPROPRIATE COST OF COMMON EQUITY?

A. Yes. My research on the subject strictly pertaining to utilities indicates that the size of the utility is not a determinate of the cost of capital. The research includes an article by Annie Wong, entitled "Utility Stocks and the Size Effect: An Empirical Analysis", Journal of the Midwest Finance Association, 1993 pp. 95-101. In the article, Ms. Wong concludes, in pertinent part:

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

Q. IS SUCH A RELATIVE SIZE ADJUSTMENT APPROPRIATE?

A. No. Mr. Hanley's size adjustment relies on a generalization based on data for all industries. His adjustment is in error because it is not specific to utilities.

Q. CONCERNING YOUR SECOND AREA OF DISAGREEMENT WITH MR. HANLEY'S ANALYSIS, PLEASE EXPLAIN WHAT YOU MEAN BY HIS UNADJUSTED COST RATE OF EQUITY RECOMMENDATION OF 11.0% IS NOT SUPPORTED BY HIS TESTIMONY AND ANALYSIS?

A. On page 3, lines 4 – 10, Mr. Hanley states that his analysis consisted of four (4) methods, namely the DCF, CAPM, RP, CE methods. On page 6, lines 4 – 10, Mr. Hanley reiterates, that his unadjusted cost rate of equity recommendation for a cost rate of equity for the gas distribution industry was based on the above referenced methods without consideration given to the CEM (Comparable Earnings Method). Mr. Hanley refers to his Schedule 1, page 2, which does contain the beginning number of 11.0% cost rate. I would point out, however, that the average result of the three methods utilized is 10.54%, without giving any consideration to the CEM.

Q. WHAT IS THE AVERAGE RESULT WHEN THE CEM (COMPARABLE EARNINGS METHOD) IS UTILIZED?

A. When the Comparable Earnings method is included in the mix, the beginning cost of equity estimate based on the Company's numbers is 12.42%.

Q. DID YOU INQUIRE AS TO HOW THE BEGINNING NUMBER OF 11.0% WAS ATTAINED?

A. Yes. In a data request, OTS-RR-15-D, I specifically requested the Company provide a detailed explanation as to how the beginning figure was obtained.

Q. WHAT WAS THE COMPANY'S RESPONSE?

A. The Company provided the following response to my data request:

> "The 11.00% cost rate is the result of the exercise of Mr. Hanley's informed expert judgment . . ."

Q. DID THE COMPANY GIVE ANY OTHER PLAUSIBLE EXPLANATION AS TO HOW HIS RECOMMENDATION OF 11.0% WAS COMPUTED?

A. No. Mr. Hanley has made no attempt to reconcile the difference between the 11.0% and the 10.54%. In addition, this difference would have been larger had Mr. Hanley not chosen to arbitrarily dismiss all his analysis that resulted in a cost of equity below 9.50%. The basis for this decision was given on page 35, lines 5 – 6 of his direct testimony, where Mr. Hanley states that we are in an environment of consistently rising interest rates. I find this perplexing since the Federal Reserve has lowered its targeted funds rate from a rate of 5.25% during September of 2007 to a current position of 2.00% (OTS Exhibit No. 1, Schedule No. 6). This would stand in direct contradiction to Mr. Hanley's assertion as to why he rejected certain cost of equity results.

Q. TURNING NOW TO YOUR THIRD AREA OF DISAGREEMENT WITH THE COMPANY'S WITNESS' TESTIMONY, PLEASE EXPLAIN THE SPECIFIC ERRORS THE COMPANY'S WITNESS MADE IN HIS ANALYSIS.

A. The Company's witness inflated his final results by making inappropriate adjustments totaling ninety-five (95) basis points to his analysis. The specific nature of these adjustments are as follows, a lack of protection in rate design adjustment of twenty basis points (0.20%); a size adjustment of twenty-five basis points (0.25%) and a fifty basis (0.50%) due to perceived increased risk due to competition to his final result.

Q. IN REFERENCE TO THE FIRST ADJUSTMENT, LACK OF PROTECTION IN RATE DESIGN, WHY SHOULD THE ALJ AND THE COMMISSION REJECT THIS UPWARD ADJUSTMENT TO MR. HANLEY'S RECOMMENDATION?

A. This adjustment is based on the concept of revenue decoupling. To the best of my knowledge, the Pa PUC has not instituted such programs. The basic tenet of these programs is to effectively shift most of the financial risk from companies and shareholders to the customers of utilities. As such, the states that have implemented these programs have required the utilities within those states to follow certain criteria. Examples of these criteria are rate freezes, stay out provisions, revenue sharing and conservation requirements. Since the Company is not required to participate in these programs it would be inappropriate to reward the shareholders and the Company in this instance.

Q. CONCERNING MR. HANLEY'S COMPANY SIZE ADJUSTMENT, PLEASE EXPLAIN WHY THIS ADJUSTMENT IS UNWARRANTED?

A. Mr. Hanley's size adjustment of twenty-five basis points (0.25%) to the cost of equity is unwarranted for the same reasons that size should not be a criterion for selecting a barometer group.

Q. WHY SHOULD MR. HANLEY'S FIFTY BASIS POINT (0.50%) ADJUSTMENT TO COMPENSATE FOR DIRECT HEAD TO HEAD COMPETITION BE REJECTED?

A. Mr. Hanley proposes this adjustment based on perceived competition in the downtown Pittsburgh area. The Company's witness states that this has lead to significant decreases in operating income for Equitable. Mr. Hanley failed to detail the exact amount of competition. The total number of customers involved is 500 in "head to head' competition.[8] The 500 customers represent 0.182% (500/275,000) of Equitable's total customer base. Mr. Hanley may interpret this as a significant percentage, but in reality it is minuscule.

I would also add, the situation that exists between the Company and other utilities is not a new issue. My research indicates that this issue has existed for several decades.

[8] Source: Federal Trade Commission, plaintiff, v. Equitable Resources, Inc., Dominion Resources, Inc., Consolidated Natural Gas Company, The Peoples Natural Gas Company, defendants, and Pennsylvania Public Utility Commission and Commonwealth of Pennsylvania (through its Attorney General), Amicus Curiae, 512 F. Supp. 2d 361; 2007 U.S. Dist. LEXIS 35061; 2007-1 Cas. (CCH) P75,702

Q. MR. HANLEY OPINES THAT IT ALSO FACES SIGNIFICANT COMPETITION FROM OTHER SOURCES OF ENERGY, I.E. ELECTRIC. DO YOU AGREE WITH THE COMPANY'S ASSESSMENT?

A. No. Mr. Hanley has not provided any significant evidence to support his contention that Equitable faces more competition from other energy sources in comparison to the barometer group.

Q. MR. HANLEY HAS PROVIDED ANALYSIS EMPLOYING THE RISK PREMIUM AND CAPM MODELS. WHY SHOULD THESE MODELS BE REJECTED AS PRIMARY METHODS FOR DETERMINATION OF THE APPROPRIATE COST OF EQUITY?

A. The CAPM and RP methods give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period the risk premiums were determined. By comparing CAPM and RP results with current expected equity returns, DCF results, an investor can make rational buy and sell decisions. When expected DCF returns are higher than those indicated by the CAPM and RP historical norms, an investor would have an incentive to buy, and vice versa.

The relevancy of these methods does not carry over from the investment decision making process to the regulatory process because regulators can never be certain that the economic and regulatory conditions in the future will be the same as those underlying the historical period during which the risk premiums were calculated.

Q. GIVEN THAT THE ECONOMIC AND REGULATORY CONDITIONS TODAY ARE DIFFERENT FROM THE HISTORICAL PERIOD, HOW DOES THIS AFFECT THE RISK PREMIUMS USED IN THE MR. HANLEY'S RP AND CAPM MODELS?

A. The CAPM and RP models do not measure the current rate of return on common equity directly, as does the DCF model. These methods determine the rate of return on common equity by indirectly observing the current cost of debt. An implicit assumption when using these methods is that the variables determining the equity cost rate and debt cost are the same, which allows the analyst to apply a constant risk premium. Actually, the variables determining the cost rates in the two markets are different. Changing economic conditions cause these variables in the two markets to change, resulting in changing risk premiums over time. As such, the use of a constant risk premium fails to capture the effect of changing economic conditions on risk premiums over time.

Q. SHOULD THE RESULTS OF CAPM MODEL BE EMPHASIZED AS A PRIMARY PREDICTOR FOR COST OF EQUITY?

A. No. As I stated earlier, the results should only be used as a check to my primary discounted cash flow model.

Q. PLEASE EXPLAIN WHY THE CAPM IS NOT SUITABLE AS A PRIMARY METHOD FOR ESTIMATING THE COST OF CAPITAL.

A. The problem lies within the use of each variable that makes-up the equation. Academics and practitioners, alike, cannot agree on the exact value of each variable that are contained within the equation. Simply put, there is a great opportunity to manipulate the CAPM.

Q. PLEASE EXPLAIN HOW MR. HANLEY'S METHODOLOGY PRODUCED BIASED RESULTS?

A. The Company's witness use of adjusted betas has produced biased results. Mr. Hanley utilizes a median result from a traditional CAPM and what has been termed an ECAPM. The results from the ECAPM where derived from an adjusted beta. Simply put, the adjusted beta utilized by Mr. Hanley is an adjustment on a beta that is already adjusted by Value Line for the tendency for stocks to regress towards one (1).

Q. ARE THERE ANY OTHER REASONS FOR YOU TO CONCLUDE THAT THE COMPANY'S CAPM RESULTS ARE BIASED?

A. Yes. Mr. Hanley's use of inputs that were produced using the arithmetic mean should be considered suspect. As I testified earlier, the arithmetic mean will produce results that are upwardly biased.

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

A. Yes. An article which appeared in the New York Times on February 18, 1992, summarizes a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French (OTS Exhibit No. 1, Schedule No. 12). Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory, the higher a stock's beta, the higher the expected return on that stock. They found that the model did not do well in predicting actual returns and suggests the use of more elaborate multi-factor models. As a result of this information, I believe that rational investors will give less credibility to expected equity returns that are calculated using the simple CAPM model.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE CAPM?

A. In my opinion, CAPM can be useful in testing the cost of capital, however certain theoretical shortcomings of this model, when applied to a cost of capital analysis, reduce its effectiveness. CAPM is a useful tool to measure capital markets. However, the opportunity to skew or manipulate its results makes the CAPM a less reliable method compared to the more widely accepted DCF method.

Q. THE COMPANY'S WITNESS ALSO PRESENTS TESTIMONY CONCERNING COMPARABLE EARNINGS MODEL (CEM). WHY SHOULD THIS METHOD BE REJECTED FOR RATEMAKING PURPOSES?

A. The CEM method should be rejected because it measures the historical earnings/book value ratios of non-utility companies. The Company has provided absolutely no evidence that these accounting returns for non-utilities bear any relationship to a market based return for gas utilities. Moreover, this method completely contradicts the premise underlying Equitable's other methods. In all of the other methods, the Company measured returns based upon market values, including the bond returns that were subtracted from common stock returns to determine the risk premia.

Q. HAS THE COMMISSION LOOKED FAVORABLY IN THE PAST AT THE COMPARABLE EARNINGS APPROACH?

A. No. The Commission long ago recognized the problem with this method. With respect to the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility the Commission stated:

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

(*Pennsylvania Public Utility Commission v. Philadelphia Electric Co.*, (1980) 33 Pur 4th 319, 341)

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

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

Q. ARE THERE ANY OTHER REASONS WHY MR. HANLEY'S CEM RESULTS SHOULD BE REJECTED?

A. Yes. The companies in Mr. Hanley's analysis are not gas distribution utilities thus they are too dissimilar for Comparable Earnings. The companies in Mr. Hanley's CEM barometer group are simply not comparable to gas utilities in terms of their business risk/financial risk profile. Gas utilities, being monopolies with very low business risk, are able to maintain higher financial risk profiles by employing more leverage. Conversely, Mr. Hanley's CEM barometer group companies, being in an unregulated competitive environment with much higher business risk, must maintain lower financial risk profiles by employing minimal leverage.

I would also point out this method has a fatal flaw. The group of companies that the Company has chosen measures returns based on stocks. A utility measures return based on property. Due to this mismatch in basis for comparison, it is impossible to reasonably interpret the results of the CEM as being meaningful.

Q. WHAT MODEL HAS THE COMMISSION NORMALLY RELIED UPON TO DETERMINE THE COST OF COMMON EQUITY IN THE PAST?

A. Historically, the Commission has relied upon the DCF method and has looked to the CAPM as a check against the DCF findings.

Q. IN YOUR OPINION, SHOULD THE COMMISSION CONTINUE TO RELY ON THE DCF METHOD?

A. Yes. I believe that my DCF findings are appropriate for the reasons articulated in my testimony. The final figure of 10.05% is a proper calculation of the cost of common equity.

Q. TURNING NOW TO YOUR FIFTH AND FINAL AREA OF DISAGREEMENT WITH THE COMPANY'S WITNESS TESTIMONY, WOULD YOU PLEASE COMMENT ON THE ABILITY OF THE DCF EQUATION TO BE UTILIZED AS A STAND-ALONE METHOD?

A. Yes.

Q. WHY DO YOU CONSIDER THE DCF METHOD TO BE SUPERIOR?

A. The DCF method of estimating the cost of capital is superior to the other methods utilized to estimate the cost of common equity because it has the component of price in the equation. This is a major advantage that the CAPM, Risk Premium, Comparable Earnings Methods do not have when estimating the cost of common equity for a utility company.

Q. WHY DO YOU CONSIDER THE PRICE COMPONENT AN ADVANTAGE?

A. Because of significance placed upon the price component in the Efficient Market Hypothesis (EMH).

Q. PLEASE DEFINE THE EFFICIENT MARKET HYPOTHESIS?

A. Simply put, the EMH states that an investor is not capable of outperforming the market due to the fact that all available information about any company is contained within the price of the stock of that company.

Q. DOES THE EMH SPECIFICALLY MENTION THE PRICE CONCEPT?

A. Yes. The EMH has three varying forms and the semi-strong version of the EMH states the following:

> The semi strong form EMH states that all publicly available information is similarly already incorporated into asset prices. In another word, all publicly available information is fully reflected in a security's current market price. The public information stated not only past prices but also data reported in a company's financial statements, company's announcement, economic factors and others. It also implies that no one should be able to outperform the market using something that "everybody else knows". This indicates that a company's financial statements are of no help in forecasting future price movements and securing high investment returns.[9]

Q. WHAT HAVE YOU CONCLUDED FROM THIS STATEMENT?

A. That all risk associated with a specific company is accounted for in the price of the stock for that company. Thus the DCF method is superior to any other method for estimating the cost rate of common equity because it incorporates the stock price within its equation.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

[9] Source: http://www.alvinhan.com/Efficient-Market-Hypothesis.htm

APPENDIX A

Robert J. Plonski

Educational and Professional Background

Education

M.S., Finance, King's College, 1998-2001
B.S., Accounting, Marywood University, 1995-1998

Training

NARUC Utility Rate School, Clearwater, FL, October 24-29, 2004
Fundamentals of Utility Finance, Arlington, VA, April 18-19, 2005
Sox 101, Orlando, FL, December 12-14, 2006

Professional

Currently- Fixed Utility Financial Analyst
Pa. PUC-Office of Trail Staff 2004 – Present

Previous- Adjunct Professor
McCann Business School-Scranton, PA 2003 – 2004
Instructed students in a wide range of Business subjects including Investments and Intermediate Accounting I & II

Case History

I have submitted testimony on behalf of the Office of Trail Staff in the following cases:

Application to change control of American Water Works Through issuance of IPO	A-212285F0136
Duquesne Light Co.	R-00061346
T.W. Phillips Gas & Oil Co.	R-00051178
City of Dubois	R-00050671
City of Lancaster – Water	R-00051167
City of Lancaster – Sewer	R-00049862
Philadelphia Gas Works	R-00061931
Pennsylvania American Water	R-00072229
Citizens Electric	R-00072348
Wellsboro Electric	R-00072350

Columbia Gas	R-2008-2011621
NRG Energy Center Harrisburg	R-2008-2028395

I have been involved in the following cases for the Office of Trial Staff:

Little Washington Wastewater	R-00040189
	R-00040191
	R-00040192
National Fuel Gas Company	R-00050216
Pike County Gas	R-00049884
Falls Township Sewer	R-00049557
Buss Water Company	R-00049559
Myers Gas Company	R-00050259
City of Dubois-Water	R-00050671
T.W. Phillips Gas and Oil Co.	R-00051178
UGI acquisition of Southern Co.	A-1200F2000
City of Bethlehem-Water	R-00050680
CMV Sewage Company, Inc.	R-00050677
Duquesne Light Company	R-00061346
TW Phillips Gas and Oil Co.	R-00051178
National Fuel Gas Distribution Corp	R-00061246
Aqua Pennsylvania, Inc.	R-00051030
Pocono Water Works	R-00050673
Exit 11 WWTP	R-00050679
Meadows Sewer Company	R-00050672
Southern Union Company 1307(f)	R-00050538
National Fuel Gas Dist 1307(f)	R-00050216
NRG Energy Pgh.	R-00061435
PPL Gas Utilities	R-00061519
B.E. Rhodes Sewer Co.	R-00061559
Utilities Inc.-Westgate	R-0006159

OTS Exhibit No. 1
Witness: Robert Plonski

11/18/08
NBG, PA
RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Direct Testimony

of

Robert Plonski

Office of Trial Staff

Concerning:

RATE OF RETURN

OTS Exhibit No. 1
Schedule No. 1

Equitable Gas Company
OTS Recommended Weighted Cost of Capital
at December 31, 2008

	Capital Structure (1)	Cost Rates (2)	Weighted Cost of Capital (3=1x2)
(1) Long-term Debt	41.35%	6.39%	2.64%
(2) Short-term Debt	13.20%	2.26%	0.30%
(3) Common Equity	45.45%	**10.05%**	4.57%
Total	100.00%		**7.51%**

OTS Exhibit No. 1
Schedule No. 2

Equitable Gas Company
Cost of Debt
Year Ended December 2008

	December 31, 2007 (Thousands)	**Weight**	**Weighted Cost**	2006
5.15% notes, due March 1, 2018	$200,000	15.96%	0.82%	$200,000
5.15% notes, due November 15, 2012	200,000	15.96%	0.82%	200,000
5.00% notes, due October 1, 2015	150,000	11.97%	0.60%	150,000
7.75% debentures, due July 15, 2026	115,000	9.17%	0.71%	115,000
Medium-term notes:				
8.5% to 9.0% Series A, due 2009 thru 2021	50,500	4.03%	0.35%	50,500
7.3% to 7.6% Series B, due 2013 thru 2023	30,000	2.39%	0.18%	30,000
7.6% Series C, due 2018	8,000	0.64%	0.05%	18,000
		60.11%	3.53%	
				763,500
(6.50% notes due 2018 issued March 18, 2008)	500,000	39.89%	2.59%	
	1,253,500			
Less debt payable within one year	—			10,000
Total long-term debt	$1,253,500	100%	6.12%	$753,500

Source: Equitable Exhibit II, Volume 1 of 1, Rate of Return
Edgar On-Line

Atlanta Gas & Light
Weighted Cost of Debt

In millions	Year(s) due	Interest rate (1)	Weighted average interest rate (1)	Outstanding as of December 31, 2007	2006
Short-term debt					
Commercial paper	2008	5.6 %	5.4 %	$ 566	$ 508
Pivotal Utility line of credit	2008	4.5	5.4	12	17
Sequent line of credit	2008	4.5	5.4	1	2
Capital leases	2008	4.9	4.9	1	1
Current portion of long-term debt	2008	-	-	-	11
Total short-term debt		5.6 %	5.4 %	$ 580	$ 539
Long-term debt - net of current portion					
Senior notes	2011-2034	4.5–7.1 %	5.8 %	$ 1,275	$ 1,150
Gas facility revenue bonds	2022-2033	3.8 – 5.3	4.3	199	199
Medium-term notes	2012-2027	6.6 – 9.1	7.8	196	196
Capital leases	2013	4.9	4.9	6	6
Notes payable to Trusts	-	-	-	-	77
AGL Capital interest rate swaps	2011	8.8	8.8	(2)	(6)
Total long-term debt		6 %	6.1 %	$ 1,674	$ 1,622
Total debt		5.9 %	5.9 %	$ 2,254	$ 2,161

Source: Edgar On-Line

National Fuel Gas
Weighted Cost of Debt

Principal Amounts by Expected Maturity Dates (Dollars in millions)	2008	2009	2010	2011	2012	Thereafter	Total
Long-Term Fixed Rate Debt	$ 200 -1	$ 100	$ —	$ 200	$ 150	$ 349	$ 999
Weighted Average Interest Rate Paid	6.3 %	6 %	—	7.5 %	6.7 %	5.9 %	6.4 %
Fair Value = $1,024.4							

At September 30 (Thousands) $	2007	2006
Medium-Term Notes(1):		
6.0% to 7.50% due May 2008 to June 2 $	749,000	$ 749,000
Notes(1):		
5.25% to 6.5% due March 2013 to September 2022(2)	250,000	346,665
	999,000	1,095,665
Other Notes:		
Secured(3)	—	22,766
Unsecured	24	169
Total Long-Term Debt	999,024	1,118,600
Less Current Portion	200,024	22,925
$	799,000	$ 1,095,675

Source: Edgar On-Line

New Jersey Resources
Wieghted Cost of Debt

(Thousands, except share amounts)			September 30, 2007			2006
COMMON STOCK EQUITY						
Common stock, $2.50 par value; authorized !			$73,356			$72,745
2007–29,342,626; 2006–29,098,173						
Premium on common stock			261,438			253,167
Accumulated other comprehensive income, n			(931)			2,742
Treasury stock at cost and other; shares			(69948)			(65,039)
2007–1,601,518; 2006–1,473,023						
Retained earnings			380,882			358,047
Total Common stock equity			644,797			621,662
LONG-TERM DEBT				Weight	Weighted Cost	
New Jersey Natural Gas						
First mortgage bonds:		Maturity date:				
6.27%	Series X	1-Nov-08	30,000	9.0952%	0.5703%	30,000
Variable	Series AA	1-Aug-30	25,000	7.5793%	0.4548%	25,000
Variable	Series BB	1-Aug-30	16,000	4.8508%	0.2910%	16,000
6.88%	Series CC	1-Oct-10	20,000	6.0635%	0.4172%	20,000
Variable	Series DD	1-Sep-27	13,500	4.0928%	0.2456%	13,500
Variable	Series EE	1-Jan-28	9,545	2.8938%	0.1736%	9,545
Variable	Series FF	1-Jan-28	15,000	4.5476%	0.2729%	15,000
Variable	*Series GG*	1-Apr-33	18,000	5.4571%	0.3274%	18,000
5%	Series HH	1-Dec-38	12,000	3.6381%	0.1819%	12,000
4.50%	Series II	1-Aug-23	10,300	3.1227%	0.1405%	10,300
4.60%	Series JJ	1-Aug-24	10,500	3.1833%	0.1464%	10,500
4.90%	Series KK	1-Oct-40	15,000	4.5476%	0.2228%	15,000
4.77% Unsecured senior notes		15-Mar-14	60,000	18.1904%	0.8677%	60,000
	Total Debt		254,845			
New Jersey Resources						
3.75% Unsecured senior notes		15-Mar-09	25,000	7.5793%	0.2842%	25,000
6.05% Unsecured senior notes		24-Sep-17	50,000	15.1586%	0.9171%	
						332,332
Total long-term debt			329,845	100%	5.51%	

Source: Edgar On-Line

NICOR, Inc
Wieghted Cost of Debt

Consolidated Statements of Capitalization
(millions, except share data)

	31-Dec 2007			Weight	Weighted Cost		
First Mortgage Bonds							
5.875% Series due 2008	$	75		15.0000%	0.8813%	75	
5.37% Series due 2009		50		10.0000%	0.5370%	50	
6.625% Series due 2011		75		15.0000%	0.9938%	75	
7.20% Series due 2016		50		10.0000%	0.7200%	50	
5.80% Series due 2023		50		10.0000%	0.5800%	50	
6.58% Series due 2028		50		10.0000%	0.6580%	50	
5.90% Series due 2032		50		10.0000%	0.5900%	50	
5.90% Series due 2033		50		10.0000%	0.5900%	50	
5.85% Series due 2036		50		10.0000%	0.5850%	50	
		500		100%	6.14%	500	
Less: Amount due within one year		75				-	
Unamortized debt discount, net of premium		2.2				2.5	
Total long-term debt		422.8	30.90%			497.5	36.20%
Mandatorily redeemable preferred and preference stock							
Cumulative, $50 par value, 1,600,000 preferred shares authorized; and cumulative, without par value, 20,000,000 preference shares authorized (11,581 and 11,681 shares of redeemable preferred stock, 4.48% series, outstanding at December 31, 2007 and 2006, respectively)		0.6				0.6	
Common equity							
Common stock, $2.50 par value, 160,000,000 shares authorized (2,976,963 and 1,715,263 shares reserved for share-based awards and other purposes, and 45,129,88 and 44,901,454 shares outstanding, respectively)		112.8				112.3	
Paid-in capital		44.8				34.1	
Retained earnings		795.5				743	
Accumulated other comprehensive loss, net							
Cash flow hedges		(6.0)				(10.3)	
Postretirement benefit plans (includes SFAS No. 158 transition amount of $2.9 recorded in 2006)		(1.7)				(3.1)	
Foreign currency translation adjustment		(.2)				0.1	
Total accumulated other comprehensive loss		(7.9)				(13.3)	
Total common equity		945.2	69.1			876.1	63.8
Total capitalization	$	1,368.60	100.00%			1,374.20	100.00%

* Pursuant to FSP No. AUG AIR-1, Accounting for Planned Major Maintenance Activities, one of Nicor's subsidiaries, Tropical Shipping, changed its accounting method for planned major maintenance to the direct expensing method effective January 1, 2007, and retrospectively increased retained earnings by $3.5 million for the earliest period presented.

The accompanying notes are an integral part of these statements.

Source: Edgar On-Line

NSTAR
Weighted Cost of Debt

Note J. Indebtedness

I. Long-Term Debt

NSTAR's long-term debt consisted of the following:

(in thousands)	December 31, 2007	Weight	Weighted Cost	2006
Mortgage Bonds/Notes, collateralized by property of operating subsidiaries:				
NSTAR Gas				
6.54%, due September 2007	$ —	0.0%	0.0%	$ 1,429
7.04%, due September 2017	25,000	0.9579%	0.0674%	25,000
9.95%, due December 2020	25,000	0.9579%	0.0953%	25,000
7.11%, due December 2033	35,000	1.3410%	0.0953%	35,000
AES				
6.924%, due June 2021	95,949	3.6763%	0.2545%	100,087
Notes:				
NSTAR				
8.0%, due February 2010	500,000	19.1578%	1.5326%	500,000
NSTAR Electric				
9.55%, due December 2007 *	—	0.0%	0.0%	1,429
7.70%, due March 2008 *	—	0.0%	0.0%	10,000
9.37%, due January 2012 *	—	0.0%	0.0%	6,316
7.98%, due March 2013 *	—	0.0%	0.0%	25,000
9.53%, due December 2014 *	—	0.0%	0.0%	10,000
9.60%, due December 2019 *	—	0.0%	0.0%	10,000
8.47%, due March 2023 *	—	0.0%	0.0%	15,000
Debentures:				
7.80%, due May 2010	125,000	4.7894%	0.3736%	125,000
4.875%, due October 2012	400,000	15.3262%	0.7472%	400,000
4.875%, due April 2014	300,000	11.4947%	0.5604%	300,000
5.625%, due November 2017	300,000	11.4947%	0.6466%	—
5.75%, due March 2036	200,000	7.6631%	0.4406%	200,000
Bonds:				
Massachusetts Industrial Finance Agency (MIFA) bonds				
5.75%, due February 2014	15,000	0.5747%	0.0330%	15,000
HEEC				
Sewage facility revenue bonds, due through 2015	11,571	0.4433%	0.0288%	13,214
Funding Companies				
Transition Property Securitization Certificates:				
6.91%, due September 2007	—	0.0%	0.0%	41,430
3.78%, due September 2008	21,776	0.8344%	0.0315%	104,998
7.03%, due March 2010	144,365	5.5314%	0.3889%	171,624
4.13%, due September 2011	266,477	10.2102%	0.4217%	266,477
4.40%, due September 2013	144,771	5.5470%	0.2441%	144,771
Total Debt	2,609,909	100%	0.0596	2,546,775
Unamortized debt discount	(9978)			(9918)
Amounts due within one year *	(98531)			(176082)
Total long-term debt	$ 2,501,400			$ 2,360,775

Source: Edgar On-Line

Piedmont Natural Gas
Wieghted Cost of Debt

	2007 In thousands	Weight	Weighted Cost	2006
Senior Notes:				
8.51%, due 2017	$ 35000	4.2430%	0.3611%	$ 35,000
Insured Quarterly Notes:				
6.25%, due 2036	199887	24.2320%	1.5145%	200,000
Medium-Term Notes:				
7.35%, due 2009	30000	3.6369%	0.2673%	30,000
7.80%, due 2010	60000	7.2737%	0.5674%	60,000
6.55%, due 2011	60000	7.2737%	0.4764%	60,000
5.00%, due 2013	100000	12.1229%	0.6061%	100,000
6.87%, due 2023	45000	5.4553%	0.3748%	45,000
8.45%, due 2024	40000	4.8491%	0.4098%	40,000
7.40%, due 2025	55000	6.6676%	0.4934%	55,000
7.50%, due 2026	40000	4.8491%	0.3637%	40,000
7.95%, due 2029	60000	7.2737%	0.5783%	60,000
6.00%, due 2033	100000	12.1229%	0.7274%	100,000
Total	824887	100%	6.74%	825,000
Less current maturities	—			—
Total	$ 824,887			$ 825,000

Source: Edgar On-Line

South Jersey Industries
Wieghted Cost of Debt

			Weight	Weighted Cost	
Long-Term Debt: (A)					
South Jersey Gas Company:					
First Mortgage Bonds: (B)					
8.19 %	Series due 2007	-	-		2,270
6.12 %	Series due 2010	10,000	2.7933%	0.1709%	10,000
6.74 %	Series due 2011	10,000	2.7933%	0.1883%	10,000
6.57 %	Series due 2011	15,000	4.1899%	0.2753%	15,000
4.46 %	Series due 2013	10,500	2.9329%	0.1308%	10,500
5.027 %	Series due 2013	14,500	4.0503%	0.2036%	14,500
4.52 %	Series due 2014	11,000	3.0726%	0.1389%	11,000
5.115 %	Series due 2014	10,000	2.7933%	0.1429%	10,000
5.387 %	Series due 2015	10,000	2.7933%	0.1505%	10,000
5.437 %	Series due 2016	10,000	2.7933%	0.1519%	10,000
6.5 %	Series due 2016	9,873	2.7578%	0.1793%	9,893
4.6 %	Series due 2016	17,000	4.7486%	0.2184%	17,000
4.657 %	Series due 2017	15,000	4.1899%	0.1951%	15,000
7.97 %	Series due 2018	10,000	2.7933%	0.2226%	10,000
7.125 %	Series due 2018	20,000	5.5866%	0.3980%	20,000
5.587 %	Series due 2019	10,000	2.7933%	0.1561%	10,000
7.7 %	Series due 2027	35,000	9.7765%	0.7528%	35,000
5.55 %	Series due 2033	32,000	8.9385%	0.4961%	32,000
6.213 %	Series due 2034	10,000	2.7933%	0.1735%	10,000
5.45 %	Series due 2035	10,000	2.7933%	0.1522%	10,000
Series A 2006 Bonds at variable rates due 2036 (C)		25,000	6.9832%	0.4190%	25,000
Marina Energy LLC: (D)					
Series A 2001 Bonds at variable rates due 2031		20,000	5.5866%	0.3352%	20,000
Series B 2001 Bonds at variable rates due 2021		25,000	6.9832%	0.4190%	25,000
Series A 2006 Bonds at variable rates due 2036		16,400	4.5810%	0.2749%	16,400
AC Landfill Energy, LLC: (E)					
Bank Term Loan, 6% due 2014		548	0.1531%	0.0092%	647
Mortgage Bond, 4.19% due 2019		1,181	0.3299%	0.0138%	1,181
Total Long-Term Debt Outstanding		358,002	100%	5.97%	360,391
Less Current Maturities		(106)			(2,369)
Total Long-Term Debt		357,896			358,022

(A) The long-term debt maturities and sinking fund requirements for the succeeding five years are as follows: 2008, $106; 2009, $112; 2010, $10,119; 2011, $25,126 and 2012, $2,320.

(B) *SJG's First Mortgage dated October 1, 1947, as supplemented, securing the First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility plant.*

(C) On April 20, 2006, SJG issued $25.0 million of tax exempt, auction rate debt through the New Jersey Economic Development Authority (NJEDA) under its $150.0 million MTN Program. As of December 31, 2007, $115.0 million remains available under the program.

(D) Marina has issued $61.4 million of unsecured variable-rate revenue bonds through the (NJEDA). The variable rates at December 31, 2007 for the Series A 2001, Series B 2001, and Series A 2006 bonds were 3.43%, 4.90% and 3.48% respectively.

(E) The debt of AC Landfill Energy is secured by a first mortgage interest in plant and equipment, and an assignment of rents and leases of the facility.

The accompanying notes are an integral part of the consolidated financial statements.

Source: Edgar On-Line

WGL Holdings
Wieghted Cost of Debt

(In thousands, except shares)		September 30, 2007		Weight	Weighted Cost		2006	
Common Shareholders' Equity								
Common stock, no par value, 120,000,000 shares authorized, 49,316,211 and 48,878,499 shares issued, respecti	$	490,257				$	477,871	
Paid-in capital		12,428					8,178	
Retained Earnings		481,274					440,587	
Accumulated other comprehensive loss, net of taxes		(3,192)					(4,829)	
Total Common Shareholders' Equity		980,767	60.40%				921,807	60.4 %
Preferred Stock								
WGL Holdings, Inc., without par value, 3,000,000 shares authorized, none issued		–					–	
Washington Gas Light Company, without par value, 1,500,000 shares authorized—issued and outstanding:								
$4.80 series, 150,000 shares		15,000					15,000	
$4.25 series, 70,600 shares		7,173					7,173	
$5.00 series, 60,000 shares		6,000					6,000	
Total Preferred Stock		28,173	1.70%				28,173	1.8 %
Long-Term Debt								
Washington Gas Light Company Unsecured Medium-Term Notes								
Due fiscal year 2008, 6.51% to 6.61%		20,100		3.1524%	0.2068%		20,100	
Due fiscal year 2009, 5.49% to 6.92%		75,000		11.7627%	0.7299%		75,000	
Due fiscal year 2010, 7.50% to 7.70%		24,000		3.7641%	0.2861%		24,000	
Due fiscal year 2011, 6.64%		30,000		4.7051%	0.3124%		30,000	
Due fiscal year 2012, 5.90% to 6.05%		77,000		12.0764%	0.7125%		77,000	
Due fiscal year 2014, 4.88% to 5.17%		67,000		10.5080%	0.5280%		67,000	
Due fiscal year 2015, 4.83%		20,000		3.1367%	0.1515%		20,000	
Due fiscal year 2016, 5.17%		25,000		3.9209%	0.2027%		25,000	
Due fiscal year 2023, 6.65%		20,000		3.1367%	0.2086%		20,000	
Due fiscal year 2025, 5.44%		40,500		6.3519%	0.3455%		40,500	
Due fiscal year 2027, 6.40% to 6.82%		125,000		19.6045%	1.2959%		125,000	
Due fiscal year 2028, 6.57% to 6.85%		52,000		8.1555%	0.5472%		52,000	
Due fiscal year 2030, 7.50%		8,500		1.3331%	0.1000%		8,500	
Due fiscal year 2036, 5.70% to 5.78%		50,000		7.8419%	0.4501%		50,000	
Total Unsecured Medium Term-Term Notes		634,100					634,100	
Other long-term debt		3,509		0.5503%	0.0330%		3,235	
		637,609		100%	6.11%			
Unamortized discount		(96)					(202)	
Less—current maturities		21,094					60,994	
Total Long-Term Debt		616,419	37.90%				576,139	37.8 %
Total Capitalization	$	1,625,359	100.00%			$	1,526,119	100 %

Source: Edgar On-Line

Average Weighted Cost of Debt
For Companies in OTS
Barometer Group

Atlanta Gas and Light	5.90%
National Fuel Gas	6.30%
New Jersey Resources	5.51%
NICOR	6.14%
NSTAR	5.96%
Piedmont	6.74%
South Jersey Industries	5.97%
WGL Holdings	6.11%
Average	6.08%

Capital Structures
For Gas Companies in Barometer Group
Years Ending December 31, 2002 - 2007

	2007	2006	2005	2004	2003	2002	%'s 2007
AGL RESOURCES INC							
B/S - Long-Term Debt (Total) (MM$)	1674.000	1622.000	1615.000	1623.000	956.100	994.200	42.76%
B/S - Debt (Long-Term Due Within One Year) (MM:	0.000	0.000	0.000	0.000	77.000	30.000	0.00%
B/S - Short-Term Debt (Total) (MM$)	580.000	539.000	522.000	334.000	306.400	388.600	0.148
B/S - Common Equity-Total (MM$)	1661.000	1609.000	1499.000	1385.000	945.300	710.100	42.43%
	3915.000	3770.000	3636.000	3342.000	2284.800	2122.900	100.00%
NATIONAL FUEL GAS CO							
B/S - Long-Term Debt (Total) (MM$)	799.000	1095.675	1119.012	1133.317	1147.779	1145.341	30.39%
B/S - Debt (Long-Term Due Within One Year) (MM:	200.024	22.925	9.393	14.260	241.731	160.564	7.61%
B/S - Short-Term Debt (Total) (MM$)	0.000	0.000	0.000	156.800	118.200	265.386	0.00%
B/S - Common Equity-Total (MM$)	1630.119	1443.562	1229.583	1253.701	1137.390	1006.858	62.00%
	2629.143	2562.162	2357.988	2558.078	2645.100	2578.149	100.00%
NEW JERSEY RESOURCES CORP							
B/S - Long-Term Debt (Total) (MM$)	383.184	332.332	317.204	315.887	257.899	370.628	29.73%
B/S - Debt (Long-Term Due Within One Year) (MM:	4.338	3.739	3.253	27.736	2.448	26.942	0.34%
B/S - Short-Term Debt (Total) (MM$)	256.479	280.700	174.100	259.700	185.800	59.900	19.90%
B/S - Common Equity-Total (MM$)	644.797	621.662	438.052	467.917	418.941	361.453	50.03%
	1288.798	1238.433	932.609	1071.240	865.088	818.923	100.00%

Capital Structures
For Gas Companies in Barometer Group
Years Ending December 31, 2002 - 2007

	2007	2006	2005	2004	2003	2002	%'s 2007
NICOR							
B/S - Long-Term Debt (Total) (MM$)	423.400	498.100	486.400	496.900	496.900	396.200	23.36%
B/S - Debt (Long-Term Due Within One Year) (MM:	75.000	0.000	50.000	0.200	0.000	100.000	4.14%
B/S - Short-Term Debt (Total) (MM$)	369.000	350.000	586.000	490.000	575.000	315.000	20.36%
B/S - Common Equity-Total (MM$)	945.200	872.600	811.300	749.100	754.600	728.400	52.15%
	1812.600	1720.700	1933.700	1736.200	1826.500	1539.600	100.00%
NSTAR							
B/S - Long-Term Debt (Total) (MM$)	2501.400	2360.775	2402.377	2101.402	1982.531	2091.355	53.14%
B/S - Debt (Long-Term Due Within One Year) (MM:	98.531	176.082	123.140	149.245	230.033	212.746	2.09%
B/S - Short-Term Debt (Total) (MM$)	403.400	436.400	417.500	161.400	239.100	198.600	8.57%
B/S - Common Equity-Total (MM$)	1703.815	1582.563	1535.015	1440.882	1361.592	1299.305	36.20%
	4707.146	4555.820	4478.032	3852.929	3813.256	3802.006	100.00%
PIEDMONT NATURAL GAS CO							
B/S - Long-Term Debt (Total) (MM$)	824.887	825.000	625.000	660.000	460.000	462.000	43.44%
B/S - Debt (Long-Term Due Within One Year) (MM:	0.000	0.000	35.000	0.000	2.000	47.000	0.00%
B/S - Short-Term Debt (Total) (MM$)	195.500	170.000	158.500	109.500	555.059	46.500	10.30%
B/S - Common Equity-Total (MM$)	878.374	882.925	884.192	854.898	630.195	589.596	46.26%
	1898.761	1877.925	1702.692	1624.398	1647.254	1145.096	100.00%

Source: S&P Database

Capital Structures
For Gas Companies in Barometer Group
Years Ending December 31, 2002 - 2007

	2007	2006	2005	2004	2003	2002	%'s 2007
SOUTH JERSEY INDUSTRIES INC							
B/S - Long-Term Debt (Total) (MM$)	357.896	358.022	319.066	328.914	308.781	273.016	37.38%
B/S - Debt (Long-Term Due Within One Year) (MM:	0.106	2.369	2.364	5.348	5.273	10.696	0.01%
B/S - Short-Term Debt (Total) (MM$)	118.290	194.600	147.300	92.300	112.800	166.500	12.36%
B/S - Common Equity-Total (MM$)	481.080	443.036	391.185	344.412	297.961	237.792	50.25%
	957.372	998.027	859.915	770.974	724.815	688.004	100.00%
WGL HOLDINGS INC							
B/S - Long-Term Debt (Total) (MM$)	616.419	576.139	584.150	590.164	636.650	667.951	34.20%
B/S - Debt (Long-Term Due Within One Year) (MM:	21.094	60.994	50.122	60.639	12.180	42.396	1.17%
B/S - Short-Term Debt (Total) (MM$)	184.247	177.376	40.876	95.634	166.662	90.865	10.22%
B/S - Common Equity-Total (MM$)	980.767	921.807	893.992	853.424	818.218	766.403	54.41%
	1802.527	1736.316	1569.140	1599.861	1633.710	1567.615	100.00%

Source: S&P Database

Average Level of LTD, STD and Equity
For Gas Company Barometer Group
For Years Ended 2002 - 2007

	Average LTD	Average STD	Average Common Equity
AGL RESOURCES INC	45.37%	14.20%	40.43%
NATIONAL FUEL GAS CO	46.26%	3.48%	50.26%
NEW JERSEY RESOURCES CORP	33.71%	19.04%	47.24%
NICOR INC	28.71%	25.19%	46.10%
NSTAR	57.39%	7.19%	35.42%
PIEDMONT NATURAL GAS CO	39.88%	12.19%	47.93%
SOUTH JERSEY INDUSTRIES INC	39.80%	16.79%	43.41%
WGL HOLDINGS INC	39.70%	7.50%	52.80%
Median	39.84%	13.19%	46.67%
Average	41.35%	13.20%	45.45%
High	57.39%	25.19%	52.80%
Low	28.71%	3.48%	35.42%

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Eight Gas Distribution Companies

	Time Period	Adjusted Dividend Yield(1)	Growth Rate	Expected Rate of Return
		(1)	(2)	(3=1+2)
(1)	52 Week Average (ending 8/8/08)	4.00%	5.30%	9.30%
(2)	Spot Price (ending 8/5/08)	4.06%	5.30%	9.36%
(3)	Average:	4.03%	5.30%	**9.33%**

Notes: (1) Value Line's reported dividends are projected for the year ahead. The dividends not estimated by Value Line were increased by 1/2 the growth rate.

Sources: Value Line, On-line Ratings and Reports, August 5, 2008

OTS Exhibit No. 1
Schedule No. 5
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Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Eight Gas Distribution Companies

Time Period	Adjusted Dividend Yield(1)	Growth Rate	Expected Rate of Return
	(1)	(2)	(3=1+2)
(1) 52 Week Average (ending 8/8/08)	4.00%	6.80%	10.80%
(2) Spot Price (ending 8/5/08)	4.06%	6.80%	10.86%
(3) Average:	4.03%	6.80%	**10.83%**

Notes: (1) Value Line's reported dividends are projected for the year ahead. The dividends not estimated by Value Line were increased by 1/2 the growth rate.

Sources: Value Line, On-line Ratings and Reports, August 5, 2008

Expected Growth Rates for the Barometer Group of Gas Distribution Companies

Company	Value Line Earnings Growth	MSN Money Growth	Yahoo Finance Earnings Growth	Morningstar Earnings Growth	Value Line 5yr Historic Growth
	(1)	(2)	(3)	(4)	(5)
(1) AGL Resources Inc.	3.5	4.8	5.3	5.8	15.0
(2) National Fuel Gas	4.5	8.0	5.0	6.0	5.0
(3) New Jersey Resources	6.5	8.0	6.0	5.2	6.0
(4) NICOR	4.5	5.8	4.5	4.2	-1.5
(5) NSTAR	7.5	6.4	6.0	6.3	3.5
(6) Piedmont Natural Gas Co.	6.0	5.4	5.8	5.8	6.0
(7) South Jersey Industries	6.0	8.3	7.0	8.0	12.0
(8) WGL Holdings, Inc.	3.5	7.5	4.0	5.5	5.0
(9) Eight Company Avg	5.3	6.8	5.4	5.9	6.4

Sources:

Value Line Investment Survey On-line, August 5, 2008
Barron's On-Line, August 8, 2008
Yahoo Finance.com, August 5, 2008
MorningStar.com, August 5, 2008
MSN Money.com, August 5, 2008

Comparison of Key Economic Variables to the Dividend Yields for the Barometer Group of Gas Companies
for 1982 to 2007 and Estimates for 2008 to 2019

	Year	'Aaa' Corporate Bond Yield (1)	10-Year Treasury Bonds (2)	Prime Rate (3)	CPI Percent Change (4)	Barometer Group Dividend Yields (5)
(1)	1982	13.79	13.00	14.86	3.80	10.96
(2)	1983	12.04	11.10	10.79	3.80	10.26
(3)	1984	12.71	12.44	12.04	4.00	9.84
(4)	1985	11.37	10.62	9.93	3.80	8.38
(5)	1986	9.02	7.68	8.33	1.10	6.73
(6)	1987	9.38	8.39	8.21	4.40	6.58
(7)	1988	9.71	8.85	9.32	4.40	7.03
(8)	1989	9.26	8.49	10.87	4.60	6.75
(9)	1990	9.32	8.55	10.01	6.10	6.53
(10)	1991	8.77	7.86	8.46	3.10	6.55
(11)	1992	8.14	7.01	6.25	2.90	6.15
(12)	1993	7.22	5.87	6.00	2.70	5.21
(13)	1994	7.96	7.09	7.15	2.70	5.80
(14)	1995	7.59	6.57	8.83	2.50	6.20
(15)	1996	7.37	6.44	8.27	3.30	5.58
(16)	1997	7.26	6.35	8.44	1.70	5.14
(17)	1998	6.53	5.26	8.35	1.60	4.51
(18)	1999	7.04	5.65	8.00	2.70	4.65
(19)	2000	7.62	6.03	9.23	3.40	4.89
(20)	2001	7.08	5.02	6.99	1.60	4.53
(21)	2002	6.49	4.61	4.67	2.40	4.63
(22)	2003	5.67	4.01	4.12	1.90	4.61
(23)	2004	5.63	4.27	4.36	3.30	4.23
(24)	2005	5.24	4.29	6.23	3.80	3.70
(25)	2006	5.36	4.80	8.25	2.00	3.95
(26)	2007	5.56	4.26	8.05	4.10	3.61
	Recent Forecasts:					
(27)	2008-3rd Qtr	5.70	4.00	5.00	5.70	
(28)	2008-4th Qtr	5.70	4.00	5.00	2.80	
(29)	2009-1st- Qtr	5.80	4.10	5.10	2.60	
(30)	2009-2nd Qtr	5.90	4.30	5.30	2.20	
(31)	2009-3rd Qtr	6.00	4.40	5.60	2.40	
(32)	2009-4th Qtr	6.10	4.60	5.90	2.40	
	Extended Forecasts:					
(33)	2010	6.00	4.30	5.50	2.50	
(34)	2011	6.30	4.90	6.60	2.40	
(35)	2012	6.40	5.20	7.20	2.40	
(36)	2013	6.50	5.30	7.40	2.40	
(37)	2014	6.50	5.30	7.30	2.40	
(38)	2015-2019	6.50	5.30	7.30	2.40	

Note: Correlation Coefficent = 0.98
Regression R Squared = 0.96

Sources: Blue Chip Financial Forecasts, September, 2008

OTS Exhibit No. 1
Schedule No. 8

Federal Funds Target Rate											
Month/ Day	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
1-Jan	5.50%	4.75%	5.50%	6.50%	1.75%	1.25%	1.00%	2.25%	4.25%	5.25%	4.25%
1-Feb	5.50%	4.75%	5.50%	5.50%	1.75%	1.26%	1.00%	2.25%	4.50%	5.25%	3.00%
1-Mar	5.50%	4.75%	5.75%	5.50%	1.75%	1.25%	1.00%	2.50%	4.50%	5.25%	3.00%
1-Apr	5.50%	4.75%	6.00%	5.00%	1.75%	1.25%	1.00%	2.75%	4.75%	5.25%	3.00%
1-May	5.50%	4.75%	6.00%	4.50%	1.75%	1.25%	1.00%	2.75%	4.75%	5.25%	2.25%
1-Jun	5.50%	4.75%	6.50%	4.00%	1.75%	1.25%	1.00%	3.00%	5.00%	5.25%	2.00%
1-Jul	5.50%	5.00%	6.50%	3.75%	1.75%	1.00%	1.25%	3.25%	5.25%	5.25%	2.00%
1-Aug	5.50%	5.00%	6.50%	3.75%	1.75%	1.00%	1.25%	3.25%	5.25%	5.25%	2.00%
1-Sep	5.50%	5.25%	6.50%	3.50%	1.75%	1.00%	1.50%	3.50%	5.25%	5.25%	2.00%
1-Oct	5.25%	5.25%	6.50%	3.00%	1.75%	1.00%	1.75%	3.75%	5.25%	4.75%	
1-Nov	5.00%	5.25%	6.50%	2.50%	1.75%	1.00%	1.75%	4.00%	5.25%	4.50%	
1-Dec	4.75%	5.50%	6.50%	2.00%	1.25%	1.00%	2.00%	4.00%	5.25%	4.50%	

Source: Federal Reserve Board

Annual Returns on Investments				Actual Return	Actual Return + 1	Geometric Yearly Return
Year	*Stocks*	*T.Bills*	*T.Bonds*			
1928	43.81%	3.08%	0.84%	0.438112	1.4381116	43.81%
1929	-8.30%	3.16%	4.20%	-0.082979	0.9170205	-8.30%
1930	-25.12%	4.55%	4.54%	-0.251236	0.7487636	-25.12%
1931	-43.84%	2.31%	-2.56%	-0.438375	0.5616245	-43.84%
1932	-8.64%	1.07%	8.79%	-0.086424	0.9135764	-8.64%
1933	49.98%	0.96%	1.86%	0.499822	1.4998223	49.98%
1934	-1.19%	0.30%	7.96%	-0.011886	0.9881143	-1.19%
1935	46.74%	0.23%	4.47%	0.467404	1.4674042	46.74%
1936	31.94%	0.15%	5.02%	0.319434	1.3194341	31.94%
1937	-35.34%	0.12%	1.38%	-0.353367	0.6466327	-35.34%
1938	29.28%	0.11%	4.21%	0.292827	1.2928265	29.28%
1939	-1.10%	0.03%	4.41%	-0.010976	0.9890244	-1.10%
1940	-10.67%	0.04%	5.40%	-0.106729	0.8932713	-10.67%
1941	-12.77%	0.02%	-2.02%	-0.127715	0.8722854	-12.77%
1942	19.17%	0.33%	2.29%	0.191738	1.1917376	19.17%
1943	25.06%	0.38%	2.49%	0.250613	1.2506131	25.06%
1944	19.03%	0.38%	2.58%	0.190307	1.1903068	19.03%
1945	35.82%	0.38%	3.80%	0.358211	1.3582108	35.82%
1946	-8.43%	0.38%	3.13%	-0.084291	0.9157085	-8.43%
1947	5.20%	0.38%	0.92%	0.052	1.052	5.20%
1948	5.70%	0.95%	1.95%	0.057046	1.0570458	5.70%
1949	18.30%	1.16%	4.66%	0.183032	1.1830322	18.30%
1950	30.81%	1.10%	0.43%	0.308055	1.3080554	30.81%
1951	23.68%	1.34%	-0.30%	0.236785	1.2367846	23.68%
1952	18.15%	1.73%	2.27%	0.18151	1.1815099	18.15%
1953	-1.21%	2.09%	4.14%	-0.012082	0.987918	-1.21%
1954	52.56%	1.60%	3.29%	0.525633	1.5256332	52.56%
1955	32.60%	1.15%	-1.34%	0.325973	1.3259733	32.60%
1956	7.44%	2.54%	-2.26%	0.074395	1.0743951	7.44%
1957	-10.46%	3.21%	6.80%	-0.104574	0.8954264	-10.46%
1958	43.72%	3.04%	-2.10%	0.4372	1.4371995	43.72%
1959	12.06%	2.77%	-2.65%	0.120565	1.1205646	12.06%
1960	0.34%	4.49%	11.64%	0.003365	1.0033654	0.34%
1961	26.64%	2.25%	2.06%	0.266377	1.2663771	26.64%
1962	-8.81%	2.60%	5.69%	-0.088115	0.9118854	-8.81%
1963	22.61%	2.87%	1.68%	0.226119	1.2261193	22.61%
1964	16.42%	3.52%	3.73%	0.164155	1.1641546	16.42%

Source: http://pages.stern.nyu.edu/~adamodar/pc/datasets/histretSP.xls

Annual Returns on Investments						
Year	*Stocks*	*T.Bills*	*T.Bonds*	**Actual Return**	**Actual Return + 1**	**Geometric Yearly Return**
1965	12.40%	3.84%	0.72%	0.123992	1.1239924	12.40%
1966	-9.97%	4.38%	2.91%	-0.09971	0.9002905	-9.97%
1967	23.80%	4.96%	-1.58%	0.23803	1.2380297	23.80%
1968	10.81%	4.97%	3.27%	0.108149	1.1081486	10.81%
1969	-8.24%	5.96%	-5.01%	-0.082414	0.9175863	-8.24%
1970	3.56%	7.82%	16.75%	0.035611	1.0356114	3.56%
1971	14.22%	4.87%	9.79%	0.142212	1.1422115	14.22%
1972	18.76%	4.01%	2.82%	0.187554	1.1875536	18.76%
1973	-14.31%	5.07%	3.66%	-0.14308	0.8569195	-14.31%
1974	-25.90%	7.45%	1.99%	-0.259018	0.7409821	-25.90%
1975	37.00%	7.15%	3.61%	0.369951	1.3699514	37.00%
1976	23.83%	5.44%	15.98%	0.23831	1.23831	23.83%
1977	-6.98%	4.35%	1.29%	-0.069797	0.930203	-6.98%
1978	6.51%	6.07%	-0.78%	0.065093	1.0650928	6.51%
1979	18.52%	9.08%	0.67%	0.185195	1.1851949	18.52%
1980	31.74%	12.04%	-2.99%	0.317352	1.3173525	31.74%
1981	-4.70%	15.49%	8.20%	-0.047024	0.9529761	-4.70%
1982	20.42%	10.85%	32.81%	0.204191	1.2041906	20.42%
1983	22.34%	7.94%	3.20%	0.223372	1.2233716	22.34%
1984	6.15%	9.00%	13.73%	0.061461	1.0614614	6.15%
1985	31.24%	8.06%	25.71%	0.312351	1.3123515	31.24%
1986	18.49%	7.10%	24.28%	0.184946	1.1849458	18.49%
1987	5.81%	5.53%	-4.96%	0.058127	1.0581272	5.81%
1988	16.54%	5.77%	8.22%	0.165372	1.1653719	16.54%
1989	31.48%	8.07%	17.69%	0.314752	1.3147518	31.48%
1990	-3.06%	7.63%	6.24%	-0.030645	0.9693555	-3.06%
1991	30.23%	6.74%	15.00%	0.302348	1.3023484	30.23%
1992	7.49%	4.07%	9.36%	0.074937	1.0749373	7.49%
1993	9.97%	3.22%	14.21%	0.099671	1.0996705	9.97%
1994	1.33%	3.06%	-8.04%	0.013259	1.0132592	1.33%
1995	37.20%	5.60%	23.48%	0.371952	1.371952	37.20%
1996	23.82%	5.14%	1.43%	0.238175	1.2381746	23.82%
1997	31.86%	4.91%	9.94%	0.318576	1.318576	31.86%
1998	28.34%	5.16%	14.92%	0.28338	1.2833795	28.34%
1999	20.89%	4.39%	-8.25%	0.208854	1.2088535	20.89%
2000	-9.03%	5.37%	16.66%	-0.090318	0.9096818	-9.03%
2001	-11.85%	5.73%	5.57%	-0.118498	0.8815024	-11.85%
2002	-21.98%	1.80%	15.12%	-0.219765	0.780235	-21.98%
2003	28.41%	1.80%	0.38%	0.284115	1.2841149	28.41%
2004	10.70%	2.18%	4.49%	0.107041	1.107041	10.70%
2005	4.85%	4.31%	2.87%	0.04848	1.0484801	4.85%
2006	15.63%	4.88%	1.96%	0.156262	1.1562618	15.63%
2007	5.48%	4.88%	10.21%	0.054847	1.0548474	5.48%

Geometric Mean 1928-2007 1.0980821 9.81%

OTS Exhibit No. 1
Schedule No. 10

Average Beta Calculation

	Company		Beta
(1)	AGL Resources		0.85
(2)	National Fuel Gas		1.00
(3)	New Jersey Resources		0.85
(4)	NICOR		0.95
(5)	NSTAR		0.80
(6)	Piedmont National Gas		0.85
(7)	South Jersey Inc		0.85
(8)	WGL Holdings		0.85
(9)		* Average	0.88

* Source: Value Line Survey

Equitable Gas Company
OTS Recommended CAPM Cost of Capital
at December 31, 2008

	Expected Return	Market Return	Risk Free Rate	Beta
(1)	***9.27%***	9.81% *	5.30% **	0.88 ***

(2) Expected Return = [Risk Free Rate + {(Expected Market Return - Risk Free Rate) * Beta}]

Expected Return = [5.30 + { (9.81 - 5.30) * 0.88}]

(3) * OTS Exhibit No.1, Schedule No. 8
** *OTS Exhibit No. 1, Schedule No. 5*
*** OTS Exhibit No. 1, Schedule No. 9

N.Y. Times Tue. Feb 18, 1992

OTS Exhibit No. 1
Schedule 12
Page 1 of 2

Market Place

A Study Shakes Confidence In the Volatile-Stock Theory

By ERIC N. BERG

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

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

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

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

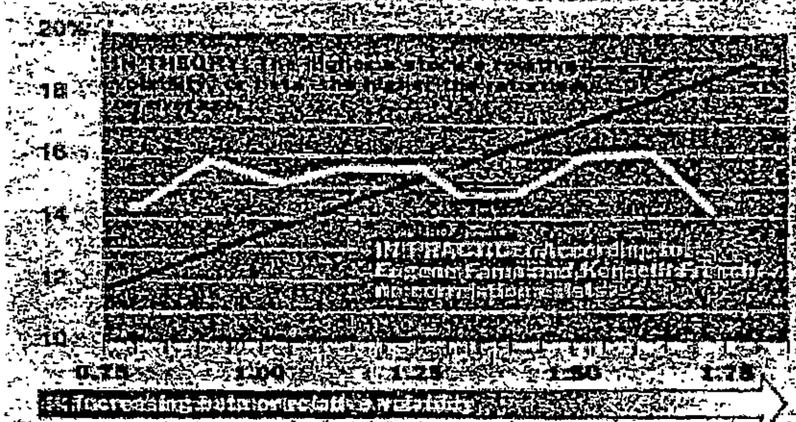
Some still favor relatively volatile stocks, among them William F. Sharpe, a retired Stanford University professor who won the 1990 Nobel Memorial Prize in Economic Science for theories based on beta. "It is a remarkable set of empirical results about what happened in the past," he said of the University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

If Professors Fama and French

Continued on Page D8

Knocking Down a Popular Theory

Annual returns on stock investments, based on relative volatility*



Beta measures the volatility of a stock relative to the market.

*Returns are based on average one-month Treasury bill yields, annualized, and average market returns, July 1963 to December 1990.

Source: Eugene F. Fama and Kenneth R. French, University of Chicago

The New York Times

the stock's price and earnings. The professors' work could force many companies to rethink the way they approach capital spending, finance scholars say.

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

* * *

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

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

* * *

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

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

But investors do earn higher returns for bearing the other type of risk, known as market risk, Professor Sharpe says. This risk, which relative to the market, the greater its long-term returns.

* * *

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

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

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

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

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

Equity Issues This Week

Docket No. R-2008-2029325
Item: OTS-RR-16-D
Respondent: Frank J. Hanley, CRRA
Position: Principal and Director, AUS Consultants

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RR-16-D

Reference Equitable Statement No. 5, direct testimony of F. J. Hanley, page 20, lines 5 - 6. Provide all evidence at Mr. Hanley's disposal that verifies adding one hundred basis points (1.00%) to the estimated 2.26%, cost rate of commercial paper, results in forward looking cost rate of short-term debt for the Company.

Response:

Please refer to Equitable Statement No. 5, Page 20, lines 6-8, Equitable Exhibit 5A, Schedule 5, Page 1 of 10, and note 6 of that page, where it states that the basis of the short-term debt cost rate of Equitable Gas Company is company-provided information where the cost of Equitable Gas Company's demand notes payable to Equitable Capital Corp. is 100 basis points (1.00%) above the 3-month commercial paper rate as also shown on Equitable Exhibit 5A, Schedule 5, Page 1 of 10.

OTS Statement No. 1-SR
Witness: Robert Plonski

11/19/08

HBG, PA

RS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Surrebuttal Testimony

of

Robert Plonski

Office of Trial Staff

Concerning:

Rate of Return

Q. **PLEASE STATE YOUR FULL NAME, EMPLOYER AND BUSINESS ADDRESS.**

A. My name is Robert Plonski. I am employed by the Pennsylvania Public Utility Commission's Office of Trial Staff. My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. **HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes. I previously submitted OTS Statement No. 1 and OTS Exhibit No. 1.

Q. **WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. The purpose of this testimony is to update my final recommendation to reflect information received since my direct testimony and to respond to the rebuttal testimony of Mr. Frank Hanley, Equitable Gas Company Statement No. 5-R.

<u>OTS Update Cost of Equity Recommendation</u>

Q. **WHAT IS YOUR UPDATED COST OF EQUITY RECOMMENDATION FOR EQUITABLE?**

A. My updated cost of equity for the Company is 10.17%, as presented on OTS Exhibit No. 1-SR, Schedule No. 1.

Q. WHAT IS THE BASIS FOR YOUR REVISED COST OF EQUITY FOR THE COMPANY?

A. My most recent DCF analysis conducted on the week ending November 7, 2008 indicates that a recommendation of a cost rate of equity for Equitable will fall in the range of 9.55% to 10.79% (OTS Exhibit No. 1-SR, Schedule No. 2, pages 1 – 2, column #3). The final recommendation of 10.17% is the midpoint of that range. OTS Exhibit No. 1-SR, Schedule No. 3 provides an updated growth rate estimates for the natural gas industry for the next five years. According to Schedule No. 3, the industry can expect to grow from 5.6% - 6.6% according to analyst's expectations.

Surrebuttal of Witness Hanley

Q. PLEASE SUMMARIZE THE ISSUES ADDRESSED IN HANLEY'S REBUTTAL TESTIMONY?

A. I have several fundamental disagreements with Witness Hanley's rebuttal testimony. These disagreements include the appropriate barometer group/size adjustment; cost rate of short-term debt; Discounted Cash Flow analysis (DCF)/the Efficient Market Hypothesis (EMH); the relevancy of the Risk Premium Method (RP); Interest Rates; Capital Asset Pricing Model (CAPM); my use of the geometric mean in the Capital Asset Pricing Model (CAPM); ECAPM; and I will end my surrebuttal with a few closing comments.

Barometer Group

Q. ON PAGE 6 AND CONTINUING ON PAGE 9 OF HIS REBUTTAL TESTIMONY, MR. HANLEY CRITICIZES YOUR USE OF A BAROMETER GROUP CONSISTING OF EIGHT GAS COMPANIES INCLUDING NSTAR. WILL YOU PLEASE RESPOND?

A. Yes. As I stated on pages 14 of my direct testimony, the use of data for one company may be less reliable than using a barometer group because the data for one company may be subject to events which can cause short-term aberrations in the marketplace. The rate of return on common equity for a single company could become distorted in these particular circumstances. The use of barometer group data has the effect of smoothing out any aberrations associated with a single company.

Q. DO YOU AGREE WITH MR. HANLEY'S CRITICISM OF YOUR INCLUSION OF NSTAR WITHIN YOU BAROMETER GROUP?

A. No. As I stated in direct testimony, no group is a perfect reflection of the company you are analyzing. Eugene Bingham refers to this concept as "pure play". Dr. Bingham at page 422 of <u>Fundamentals of Financial Management</u> states the following about the notion of "pure play" companies:

> "The pure play method approach can only be used for major assets such as whole divisions, and even then it is frequently difficult to implement because it is often impossible to find pure play proxy firms."[1]

Due to the past merger and acquisition activities within the gas industry of the past decade, this is true today. NSTAR meets the criteria as I set forth on page 15 of my direct testimony: (1) have at least two sources of analysts' forecasts of earnings growth; (2) are not the announced subject of an acquisition; (3) have a customer base of more than 300,000; (4) are located in the eastern part of the United States; (5) had a higher percentage of sales associated with utility operations than other segments of the business unit.

Q. ON PAGE 21 OF HIS REBUTTAL TESTIMONY, THE WITNESS FOR THE COMPANY REPEATS HIS ASSERTION AS WHY YOUR BAROMETER GROUP IS TO DISSIMILAR IN HIS OPINION. DO YOU AGREE?

A. No. As I just stated, NSTAR satisfied the criteria that I presented in my direct testimony. In addition Mr. Hanley's assertion that NSTAR's gas operations are "de minimis" is incorrect. NSTAR's customer base for its gas division is 300,000. This would make NSTAR's customer base larger than Equitable Gas by approximately 25,000 customers.

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[1] Eugene F. Bingham, Fundamentals of Financial Management, 5th Edition, © 1989, Holt, Rienhart and Wilson.

Q. DO YOU AGREE WITH MR. HANLEY'S ASSERTIONS THAT YOUR BAROMETER GROUP IS TOO DISSIMILAR DUE TO THE MARKET SIZE OF YOUR GROUP IS 4.0x COMPARED TO MR. HANLEY'S BEING ONLY 3.3x? (EQUITABLE STATEMENT NO. 5-R, PAGE 7, LINES 11 – 17)

A. No. Market size was not a criterion that I used to select my barometer group. As I stated on page 35 of my direct testimony, size of a utility is not a determinate of the cost of equity. As a result, size should not be a criterion for selecting a barometer group

Q. BEGINNING ON PAGE 24 AND CONTINUING TO PAGE 27, MR. HANLEY OPINES THAT A SIZE ADJUSTMENT IS NEEDED FOR EQUITABLE. DO YOU AGREE WITH HIS SIZE ADJUSTMENT?

A. No. The information available for utilities suggests that the size of the utility is not a determinant of the cost of equity. As I stated on page 31 of my direct testimony, Mr. Hanley's size adjustment relies on a generalization based on data for all industries. His adjustment is in error because it is not specific to utilities. I would also add, that on page 26, line 6, Mr. Hanley expressly states that size is company specific and diversifiable. The witness for the Company provides the specific argument for why a size adjustment is unwarranted and should be rejected (Equitable Statement No. 5-R, page 26, line 6). CAPM theory specifically states that company specific risk can be diversified away thus an investor should not earn a return for this type of risk.

Q. ON PAGE 8, LINES 8 – 11 OF HIS REBUTTAL TESTIMONY, MR. HANLEY INDICATES THAT YOUR BAROMETER GROUP DOES NOT FACE SIGNIFICANT HEAD-TO-HEAD COMPETITION. WOULD YOU PLEASE COMMENT?

A. Yes. I believe that this is an irrelevant observation on the part of Mr. Hanley. To the best of my knowledge Mr. Hanley has not presented any evidence that his proxy group experiences this so called head-to-head competition that warrants his adjustment of 0.50% (fifty basis points). It is my understanding that as of 1999, the Legislature of the Commonwealth of Pennsylvania passed the Natural Gas Choice and Competition Law to promote competition within the Commonwealth. A study by the Commission showed the following:

> In October 2005, the Commission determined that "effective competition" did not exist in the retail natural gas supply market statewide based on the lack of participation of an adequate number of natural gas suppliers and customers in the retail natural gas market, and the identification of substantial barriers in the market structure and operation that prevented the participation of these groups in the market.[2]

[2] Source: Docket No. I-00040103F0002

Q. ON PAGE 27 OF HIS REBUTTAL TESTIMONY, MR. HANLEY AGAIN OPINES THAT HIS FIFTY BASIS POINT ADJUSTMENT IS REQUIRED, BECAUSE OF THE DIRECT HEAD TO HEAD COMPETITION. DO YOU AGREE WITH MR. HANLEY'S ASSERTION?

A. No. As I testified page 35 of my direct testimony, Mr. Hanley proposes this adjustment based on perceived competition in the downtown Pittsburgh area. The Company's witness states that this has lead to significant decreases in operating income for Equitable. Mr. Hanley failed to detail the exact amount of competition. The total number of customers involved is 500 in "head to head' competition.[3] The 500 customers represent 0.182% (500/275,000) of Equitable's total customer base. Mr. Hanley may interpret this as a significant percentage, but in reality it is minuscule. The amount of customers involved is miniscule and does not have a material effect on the Company.

<u>Cost Rate of Short-term Debt</u>

Q. WHAT COST RATE OF SHORT-TERM DEBT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY?

A. I recommend a cost rate of short-term debt of 2.26%. This recommendation was based on a figure that Mr. Hanley presented in his direct testimony.

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[3] Source: Federal Trade Commission, plaintiff, v. Equitable Resources, Inc., Dominion Resources, Inc., Consolidated Natural Gas Company, The Peoples Natural Gas Company, defendants, and Pennsylvania Public Utility Commission and Commonwealth of Pennsylvania (through its Attorney General), Amicus Curiae, 512 F. Supp. 2d 361; 2007 U.S. Dist. LEXIS 35061; 2007-1 Cas. (CCH) P75,702

Q. MR. HALEY DISAGREES WITH YOUR REMOVAL OF THE 1.00% THAT HE ADDED TO THE SHORT-TERM DEBT COST RATE. DO YOU AGREE WITH HIS REASONS? (EQUITABLE STATEMENT NO. 5-R, PAGE 9, LINES 14 – 22 AND PAGE 10, LINES 1 - 11)

A. No. As I stated in my direct testimony at page 11, the Company has added an unwarranted one hundred basis points (1.00%) to the initial calculation of the cost rate of short-term debt. Mr. Hanley has not provided evidence to support his assertion that the adjustment provides a forward looking cost rate of short-term debt. I specifically asked Mr. Hanley to provide all the financial and/or academic articles that supports his claim that his proposed adjustment results in a forward looking cost rate of short-term debt (OTS-RR-16-D). His response to that data request indicated that his calculation was based on Company supplied information (OTS Exhibit No. 1-SR, Schedule No. 4). However, Mr. Hanley did not provide any documentation that supported this claim.

Q. AS PART OF HIS REBUTTAL TESTIMONY, MR. HANLEY PRESENTS SCHEDULE NO. 5 WHICH REPORTS EQUITABLE RESOURCES COST OF SHORT-TERM AT 4.55%. WHY SHOULD THIS FIGURE BE REJECTED AS A COST RATE OF SHORT-TERM DEBT?

A. The Company had a year to prepare its testimony for the case presented before the Commission. Mr. Hanley had the opportunity to present this figure well in advance of his rebuttal testimony and did not. The figure of 2.26% was the figure that was calculated by Mr. Hanley and presented by him in direct testimony.

<u>**DCF Analysis/Efficient Market Hypothesis (EMH)**</u>

Q. BEGINNING ON PAGE 10 AND CONTINUING TO PAGE 14 OF HIS REBUTTAL TESTIMONY, COMPANY WITNESS HANLEY STATES SEVERAL OPINIONS AS TO WHY YOUR RECOMMENDED COST RATE OF COMMON EQUITY OF 10.05% BASED ON THE DISCOUNTED CASH FLOW (DCF) METHOD IS IN ERROR. DO YOU AGREE WITH WHAT MR. HANLEY OPINES?

A. No. To begin, Mr. Hanley states that the DCF I employ is based on the efficient market hypothesis (EMH) and because of this no one method should be utilized when determining the cost of common equity (Equitable Statement No. 5-R, page 11, lines 15 - 18). The EMH simply states that all relevant information about a company is included in the price of the stock which is being traded. In other words, an investor, theoretically, cannot outperform the market unless they have access to information that is not publicly known.

In my professional opinion, the EMH supports my conclusions. Since price is a crucial component of the DCF equation and according to the EMH all relevant information is accounted for in a stock price, there should not be a need to make any adjustments to my recommendation. Since both Mr. Hanley and I agree that the EMH proves that all relevant information is included in the price of a stock the need for any adjustments to the cost of equity are unjustified. This would include adjustments for market to book ratios and all perceived risks.

Moreover, Mr. Hanley's other methods do not employ the stock price in their computation. All relevant information is not incorporated; therefore they fail Mr. Hanley's EMH test. As a result the DCF method provides a superior result.

Q. DOES THE EMH REQUIRE THAT INVESTORS TAKE INTO ACCOUNT ALL INFORMATION DERIVED FROM MULTIPLE METHODS WHEN CALCULATING RATES OF RETURN?

A. No. In fact, the semi-strong form of the EMH states that security prices will reflect all relevant information that is available to the public at any point in time and that the expected returns implied in the current price of the security should echo its risk. Mr. Hanley's assertion is an incorrect understanding of the EMH.

<u>Risk Premium</u>

Q. ON PAGE 11, LINES 19 - 22 MR. HANLEY STATES THAT RECENT COMMISSION DECISIONS CONFIRM HIS USE OF MULTIPLE METHODS, NOTABLY THE RISK PREMIUM AND CAPM. DO YOU AGREE?

A. No. Please note the following, in Pennsylvania Public Utility Commission, et al. v. City of Bethlehem (Water), Docket No. R-00943124, (Order Entered: March 28, 1995), *1995 Pa. PUC LEXIS 38; 160 P.U.R.4th 375*, the Commission issued the following statement concerning the use of the CAPM and Risk Premium methods:

> Generally, observed the ALJ, the Commission has criticized the Risk Premium and CAPM methodologies. In rejecting Risk Premium and CAPM analyses, the Commission has explained:
>
> [F]irst, we [i.e., the Commission] cannot accept that historic experienced earnings reflect the cost of capital. We know of no reputable analyst who would seriously argue that experienced earnings represent the cost of capital, except by pure happenstance. But, such is the inherent assumption of each methodology [Risk Premium and CAPM]. Second, we cannot accept, even assuming that historic experience earnings represented the cost of capital that the *average* premium of an equity investment over a fixed income investment over a period as long as 50 years, [*99] represents the investor required premium in today's and tomorrow's market.
>
> Accordingly, we conclude that we can place little credence in the results of these methodologies.
>
> *Pennsylvania Public Utility Commission v. Pennsylvania Power Co., 67 Pa. P.U.C. 91, 164 (1988)* (emphasis in original); *see also Pennsylvania Public Utility Commission v. Peoples Natural Gas Co., 69 Pa. P.U.C. 138, 165-68 (1989); Pennsylvania Public Utility Commission v. Pennsylvania-American Water Co., 68 Pa. P.U.C. 343, 377-78 (1988); Pennsylvania Public Utility Commission v. National Fuel Gas Distribution Corp., 67 Pa. P.U.C. 264, 331-32 (1988); Pennsylvania Public Utility Commission v. York Water Co., 62 Pa. P.U.C. 459 (1986).*

> The ALJ noted that in *Pennsylvania Public Utility Commission v. Duquesne Light Co., 66 Pa. P.U.C. 518 (1988),* the Commission declared "that the economic environment over lengthy time frames is not representative of current economic conditions and therefore does not produce realistic risk premium results."

In a later proceeding, Pennsylvania Public Utility Commission v. City of Lancaster (Water), Docket No. R-00984567, (Order Entered: September 22, 1999), *1999 Pa. PUC LEXIS 39; 197 P.U.R.4th 156,* the Commission expressed the following view as to the use of these methods:

> Generally, observed the ALJ, the Commission has criticized the Risk Premium and CAPM methodologies. In rejecting Risk Premium and CAPM analyses, the Commission has explained:
>
> First, we [i.e., the Commission] cannot accept that historic experienced earnings reflect the cost of capital. We know of no reputable analyst who would seriously argue that experienced earnings represent the cost of capital, except by pure happenstance. But, such is the inherent assumption of each methodology [*20] [Risk Premium and CAPM]. Second, we cannot accept, even assuming that historic experience earnings represented the cost of capital that the *average* premium of an equity investment over a fixed income investment over a period as long as 50 years, represents the investor required premium in today's and tomorrow's market.

Q. PLEASE COMMENT ON MR. HANLEY'S TESTIMONY BEGINNING ON PAGE 29 AND ENDING ON PAGE 31 OF EQUITABLE GAS STATEMENT 5-R CONCERNING THE USE OF THE RISK PREMIUM METHOD.

A. Mr. Hanley has not produced any new arguments as to why the Risk Premium (RP) should be given equal weight along with the DCF method as a primary method to calculate the cost rate of common equity.

Q. WHAT METHOD HAS THE COMMISSION UTILIZED AS THE PRIMARY METHOD TO CALCULATE THE COST RATE OF COMMON EQUITY FOR UTILITY COMPANIES?

A. The DCF Method.

Q. IN THAT RESPECT, YOU OBVIOUSLY DISAGREE WITH WITNESS HANLEY'S OPINION THAT METHODS OTHER THAN THE DCF MUST BE USED IN DETERMINING THE COST RATE OF COMMON EQUITY, IS THAT CORRECT?

A. Yes. The DCF method can stand alone as an appropriate and legitimate measure of the cost rate of common equity. In short, no other method directly measures the cost of equity and is therefore inferior to the DCF method. While not necessary, even if the RP and CAPM methods were to be used as a check on the DCF findings, they don't rise to the level of accuracy that would justify their use as a primary method. An even cursory review of prior Commission issued Orders discloses that the Commission agrees that the DCF method can stand alone. In fact, in Pennsylvania Public Utility Commission v. Metropolitan Edison Company, Docket No. R-00061366 and Public Utility Commission v. Pennsylvania Electric Company, Docket No. R-00061367, (Consolidated Order entered January 11, 2007), the Commission stated the following:

> As noted previously, we have primarily relied upon the DCF methodology in arriving at our determination of the proper cost of common equity. However, we agree with the ALJs' statement that other methodologies can be used as a check on the reasonableness of the results arrived at by the use of the DCF method, tempered by informed judgment.

As such, Hanley's recommended use of the CAPM and Risk Premium as primary methods for determining the cost of equity is contrary to Commission's Order in these proceedings.

Interest Rates

Q. BEGINNING ON PAGE 14 AND CONTINUING ON PAGE 15 OF HIS REBUTTAL TESTIMONY, MR. HANLEY OPINES THAT YOUR CONCLUSION THAT INTEREST RATES WILL REMAIN FAIRLY STABLE IS INCORRECT. DO YOU AGREE?

A. No. I reviewed the yields for Aaa rated debt for a thirty-three month period for the decades of the 1970's to the current decade. As shown in OTS Exhibit No. 1-SR, Schedule No. 5, current interest yields are at historical lows. Schedule No. 5 indicates that yields on Aaa debt has not been this low in three decades. Page 2 of Schedule No. 5 indicates that the variance for the sample from 2006 to 2008 has a sample variance of 0.03 with a standard deviation of 0.19. When compared to the sample from 1986 to 1988, that sample had a variance of 0.37 and a standard deviation of 0.61; I can say with relative confidence and assurance that interest rates have been stable.

Q. HOW DID YOU CONCLUDE THAT INTEREST RATES WILL REMAIN STABLE IN THE FUTURE?

A. I based my conclusion on the consensus estimates from the Blue Chip Financial Forecasts. As I testified on page 17, of OTS Statement No. 1, Forecasting professionals are also expecting interest rates on long-term "Aaa" rated corporate bonds to increase from 5.7% in the third quarter of 2008 to 6.1% by the fourth quarter of 2009. Mr. Hanley based his based his conclusion on an independent analysts with only very short-term implications.

Q. IS MR. HANLEY'S INDEPENDENT ANALYSIS CONSISTENT WITH STANDARD MACROECONOMIC THEORY?

A. No. Mr. Hanley's conclusion that interest rates rise during recessions is inconsistent with general economic theory. Mr. Hanley readily acknowledged that the economy is extremely sluggish and is very likely in recession. During recessions demand for capital declines, thereby creating downward pressure on interest rates.

CAPM

Q. BEGINNING AT PAGE 15 AND ENDING ON PAGE 19 OF HIS REBUTTAL TESTIMONY, MR. HANLEY STATES THAT YOUR CAPM RESULTS ARE UNDERSTATED BECAUSE YOUR RESULTS ARE BASED ON INPUTS ACHIEVED FROM USING THE GEOMETRIC MEAN. PLEASE COMMENT?

A. Mr. Hanley's statement is without merit. The inputs I utilized in my CAPM analysis were derived properly. In contrast, the Company's Witness has utilized inputs that have produced an upwardly biased result. Mr. Hanley's use of the arithmetic mean has produced a bias that I clearly demonstrated on pages 38 and 39 of my direct testimony.

Q. ON PAGE 30, OF EQUITABLE STATEMENT 5-R, MR. HANLEY STATES THAT YOU ARE INCORRECT IN YOUR ASSERTION THAT THERE IS A GREAT OPPORTUNITY TO MANIPULATE THE RESULTS OF THE CAPM. IS HIS ASSERTION CORRECT?

A. No. His use of the arithmetic mean is a perfect example of how the selection of improper inputs can produce upwardly biased results. The majority of the academic literature that I have reviewed indicates that the geometric mean is the better indicator of historic returns.

Q. ON PAGE 32, LINES 15 - 26, OF MR. HANLEY'S REBUTTAL TESTIMONY, MR. HANLEY STATES THAT SINCE THE 1992 ARTICLE, REFERENCED IN YOUR DIRECT TESTIMONY, THAT FAMA AND FRENCH HAVE PUBLISHED AN ARTICLE THAT SEEMS TO REVERSE THEIR POSITION ON THE CAPM. DOES MR. HANLEY CORRECTLY CHARACTERIZE THE 2004 ARTICLE?

A. No. All one has to do is to continue to the second paragraph to understand the real meaning of the article sited by Mr. Hanley. The article, that Mr. Hanley sites, is a continuation of the criticism of the CAPM. Fama and French stated the following about the CAPM:

> "Unfortunately, the empirical record of the model is poor-poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model."[4]
>
> (OTS Exhibit No. 1-SR, Schedule No 6, page 2 of 23)

[4] Eugene F. Fama and Kenneth R. French, The Journal of Economic Perspectives, Vol. 18, No. 3, (Summer, 2004), pp. 25-46

Q. DOES THE 2004 ARTICLE BY FAMA AND FRENCH LIST ANY OTHER CRITICISMS OF THE CAPM METHOD?

A. Yes. It mentions the research of Richard Roll. According to Roll, there is no true way, with any certainty, to predict the expected market return. As Fama and French note:

> "Roll (1977) argues that the CAPM has never been tested and probably never will be. The problem is that the market portfolio at the heart of the model is theoretically and empirically elusive."[5]
>
> (OTS Exhibit No. 1-SR, Schedule No 6, page 18 of 23)

<u>**Geometric Mean**</u>

Q. AT PAGE 15 THROUGH PAGE 19 OF HIS REBUTTAL TESTIMONY MR. HANLEY CRITICIZES YOUR USE OF THE GEOMETRIC MEAN. WILL YOU PLEASE COMMENT?

A. Yes. Mr. Hanley has erred in this statement. Calculation of the CAPM requires inputs that are derived from the use of geometric mean in order to avoid upwardly biased results.

[5] Eugene F. Fama and Kenneth R. French, <u>The Journal of Economic Perspectives</u>, Vol. 18, No. 3, (Summer, 2004), p. 41

Q. IS THERE A MATHEMATICAL RELATIONSHIP BETWEEN THE GEOMETRIC AVERAGE AND THE ARITHMETIC AVERAGE?

A. Yes. Page 23 of the second edition of *Stocks for the Long Run* by Professor Jeremy J. Siegel, copyright 1998, states the following:

> The geometric return is approximately equal to the arithmetic return minus one-half of the variance σ^2 of yearly returns $r_G=r_A-1/2\ \sigma^2$.
>
> Investors can be expected to realize geometric returns only over long periods of time. The average geometric return is always less than the average arithmetic return except when all yearly returns are exactly equal. This difference is related to the volatility of yearly returns.

As explained above, the only reason the arithmetic average is higher than the geometric average is because of the volatility of yearly returns.

Q. DID THE MARKET RETURN DATA YOU USED IN THE CAPM ANALYSIS SATISFY PROFESSOR SIEGEL'S CRITERIA FOR THE USE OF A GEOMETRIC MEAN RETURN?

A. Yes. I used the historic return of the S&P 500. The period I utilized was from 1928 through 2007. This period clearly satisfies the required long-term period characterized by Professor Siegel.

Q. ON PAGE 19 OF EQUITABLE STATEMENT 5-R, MR. HANLEY STATES THAT YOU INCORRECTLY INFERRED THE 2004 SITE FROM IBBOTSON ASSOCIATES YEARBOOK. IS MR. HANLEY'S STATEMENT CORRECT?

A. No. As pointed out at lines 16 – 18, of page 19, Equitable Statement No. 5-R, "The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows." Since in this instance, neither Mr. Hanley nor I used discounted cash flows to estimate the cost of common equity for Equitable, to utilize the arithmetic mean to compute the historical market return for the S&P 500 is incorrect. As astutely pointed out by Mr. Hanley, at lines 24 – 26, of page 19, the geometric mean is the more appropriate method for reporting past performance. As I have just testified, I utilized the geometric mean to compute the historical return for the S&P 500.

Q. MR. HANLEY HAS PRESENTED A SCHEDULE WHERE HE RECALCULATES YOUR CAPM RESULTS. DO YOU AGREE WITH HIS FINDINGS?

A. No. Mr. Hanley has presented nothing new. He has used inputs based on the arithmetic mean as he presented previously in direct testimony. As I have clearly demonstrated in direct testimony and in surrebuttal testimony, the use of inputs that are produced by utilizing the arithmetic mean will produce results that are overstated and upwardly biased.

ECAPM

Q. ON PAGE 20 OF MR. HANLEY'S REBUTTAL TESTIMONY, THE COMPANY'S WITNESS OPINES THAT YOUR NOT UTILIZING THE EMPIRICAL CAPM (ECAPM) HAS CAUSED YOUR CAPM RESULTS TO BE UNDERSTATED. PLEASE COMMENT?

A. Mr. Hanley also employs a variation of the CAPM known as the Empirical Capital Asset Pricing Model (ECAPM). He states that this is necessary because "the traditional CAPM understates the cost rate for common equity for companies with betas less than 1.0 and overstates the cost rate for companies with betas greater than one." The problem described is commonly known as the "Beta Stability" problem.

Q. WHY DO YOU BELIEVE THE USE OF THE ECAPM IS UNNECESSARY?

A. In Value Line's description of their betas, they state "there is a tendency over the years for high Beta Stocks to become lower and for low Beta stocks to become higher. This tendency can be measured by studying the Betas of stocks in consecutive five-year intervals. The Betas published by The Value Line Investment Survey are adjusted for this tendency and hence are likely to be a better predictor of future Betas than those based exclusively on the experience of the past five years."[6] By employing adjusted Value Line Betas with the ECAPM, Mr. Hanley is over compensating for the beta stability problem resulting in upwardly biased estimates.

<u>Ending Comments</u>

Q. BEGINNING ON PAGE 21 AND CONTINUING TO PAGE 35 OF HIS REBUTTAL TESTIMONY, MR. HANLEY PRESENTS WHAT IS ENTITLED RESPONSE TO YOUR CRITIQUE OF HIS DIRECT TESTIMONY. WOULD YOU PLEASE COMMENT ON THIS SECTION OF MR. HANLEY'S REBUTTAL TESTIMONY?

A. Yes. Mr. Hanley does not present any new evidence or positions in this section of his rebuttal testimony.

Q. MR. HALEY STATES ON PAGE 21 AND CONTINUING TO PAGE 23 THAT YOU DO NOT GIVE ANY CREDITABILITY TO HIS USE OF AVERAGING TO DEVELOP HIS INITIAL COST RATE ESTIMATE OF 11.0% FOR THE COMPANY. WOULD YOU PLEASE COMMENT?

A. Mr. Hanley's initial cost rate was not achieved by averaging the methods he utilized in direct testimony. As I stated on pages 31 – 32 of my direct testimony, on page 3, lines 4 – 10, Mr. Hanley states that his analysis consisted of four (4)

[6] <u>How to Invest in Common Stocks, the Guide to Using the Value Line Investment Survey</u>, Value Line Publishing, Inc.

methods, namely the DCF, CAPM, RP, CE. On page 6, lines 4 – 10, Mr. Hanley reiterates, that his unadjusted cost rate of equity recommendation for a cost rate of equity for the gas distribution industry was based on the above referenced methods *without consideration given to the CEM (Comparable Earnings Method).* Mr. Hanley refers to his Schedule 1, page 2, which does contain the beginning number of 11.0% cost rate. I would point out, however, that the average result of the three methods utilized is 10.54%, without giving any consideration to the CEM. Averaging the three methods does not in fact produce the initial result of 11.0% that the witness for the Company opines. It produces a result that is forty-six basis points (0.46%) lower than Mr. Hanley recommends. I would reiterate that Mr. Hanley has not provided any evidence to explain or plausible rationale why his initial recommendation is higher than the average of the methods he utilized in his analysis.

Q. ON PAGE 23 OF HIS TESTIMONY MR. HANLEY IMPLIES THAT YOU DID NOT UNDERSTAND THAT HE DID NOT UTILIZE THE COMPARABLE EARNINGS IN THIS INSTANCE. IS HE CORRECT?

A. No. As I have just explained, Mr. Hanley made it quite clear the he relied on only three methods without consideration given to the CEM.

Q. BEGINNING ON PAGE 23 AND ENDING ON PAGE 24, MR. HANLEY OPINES THAT LACK OF PROTECTION IN RATE DESIGN UNDERSTATES THE COST RATE OF COMMON EQUITY. DO YOU AGREE WITH HIS ASSERTION?

A. No. Mr. Hanley has classified these mechanisms as reducing business risk and as such the management of the Company has control to reduce such risk.

On page 639 of Eugene Bingham's book <u>Fundamentals of Financial Management</u>, Dr. Bingham defines business risk as:

> "risk which defined as the uncertainty inherent in projections of future operating income or earnings before interest and taxes (EBIT), is the most single important determinate of a firm's capital structure."

Later on page 641, Dr. Bingham list several important factors that determine business risk. The last paragraph on that page states the following concerning business risk:

> "Each of these factors is determined partly by the firm's industry's characteristics, but each is also controllable to some extent by management."

Since Mr. Hanley has classified this risk as business risk and it is controllable by management it is unimportant to potential investors.

Q. WOULD YOU PLEASE EXPLAIN?

A. Total risk is composed of non-systematic risk and systematic risk. Systematic risk is the amount of risk that can not be reduced through diversification. Diversification is the process in which investors will make-up a certain portfolio for investment purposes to reduce the exposure to risk. Non-systematic risk or business risk is also referred to as company specific risk. Investors will be able to offset a majority of the risks perceived for Equitable by building a portfolio of companies that they perceive as less risky. However, a company that is seen as having a large amount of systematic risk is quite different. Investors will demand a larger return from a company that contains systematic risk because it cannot be lessen through diversification. Since Mr. Hanley has expressed this is not the case with Equitable, his opinion that Equitable should received an upward adjustment to the cost rate of equity is without merit.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OTS Exhibit No. 1-SR
Witness: Robert Plonski

11/15/08
HBG, PA
RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Surrebuttal Testimony

of

Robert Plonski

Office of Trial Staff

Concerning:

Rate of Return

OTS Exhibit No. 1
Schedule No. 1

Equitable Gas Company
OTS Recommended Weighted Cost of Capital
at December 31, 2008

	Capital Structure (1)	Cost Rates (2)	Weighted Cost of Capital (3=1x2)
(1) Long-term Debt	41.35%	6.39%	2.64%
(2) Short-term Debt	13.20%	2.26%	0.30%
(3) Common Equity	45.45%	**10.17%**	4.62%
Total	100.00%		**7.56%**

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Eight Gas Distribution Companies

	Time Period	Adjusted Dividend Yield(1)	Growth Rate	Expected Rate of Return
		(1)	(2)	(3=1+2)
(1)	52 Week Average (ending 11/7/08)	4.19%	5.60%	9.79%
(2)	Spot Price (ending 11/7/08)	3.95%	5.60%	9.55%
(3)	Average:	4.07%	5.60%	**9.67%**

Notes: (1) Value Line's reported dividends are projected for the year ahead. The dividends not estimated by Value Line were increased by 1/2 the growth rate.

Sources: Value Line, On-line Ratings and Reports, August 5, 2008

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Eight Gas Distribution Companies

Time Period	Adjusted Dividend Yield(1)	Growth Rate	Expected Rate of Return
	(1)	(2)	(3=1+2)
(1) 52 Week Average (ending 11/7/08)	4.19%	6.60%	10.79%
(2) Spot Price (ending 11/7/08)	3.95%	6.60%	10.55%
(3) Average:	4.07%	6.60%	**10.67%**

Notes: (1) Value Line's reported dividends are projected for the year ahead. The dividends not estimated by Value Line were increased by 1/2 the growth rate.

Sources: Value Line, On-line Ratings and Reports, November 7, 2008

Expected Growth Rates
for the Barometer Group of Gas Distribution Companies

	Company	Value Line Earnings Growth	MSN Money Growth	Yahoo Finance Earnings Growth	Morningstar Earnings Growth	Value Line 5yr Historic Growth
		(1)	(2)	(3)	(4)	(5)
(1)	AGL Resources Inc.	3.0	4.8	4.8	6.5	15.0
(2)	National Fuel Gas	7.0	8.0	5.0	6.0	5.0
(3)	New Jersey Resources	8.5	8.0	6.0	6.3	6.0
(4)	NICOR	5.0	6.5	4.3	4.5	-1.5
(5)	NSTAR	7.5	6.8	7.0	6.0	3.5
(6)	Piedmont Natural Gas Co.	7.0	5.6	7.9	8.0	6.0
(7)	South Jersey Industries	6.0	5.6	6.0	7.3	12.5
(8)	WGL Holdings, Inc.	3.5	7.5	4.0	5.5	5.0
(9)	Eight Company Avg.	5.9	6.6	5.6	6.3	6.4

Sources:

Value Line Investment Survey On-line, November 7, 2008
Barron's On-Line, November 7, 2008
Yahoo Finance.com, November 7, 2008
MorningStar.com, November 7, 2008
MSN Money.com, November 7, 2008

Docket No. R-2008-2029325
Item: OTS-RR-16-D
Respondent: Frank J. Hanley, CRRA
Position: Principal and Director, AUS Consultants

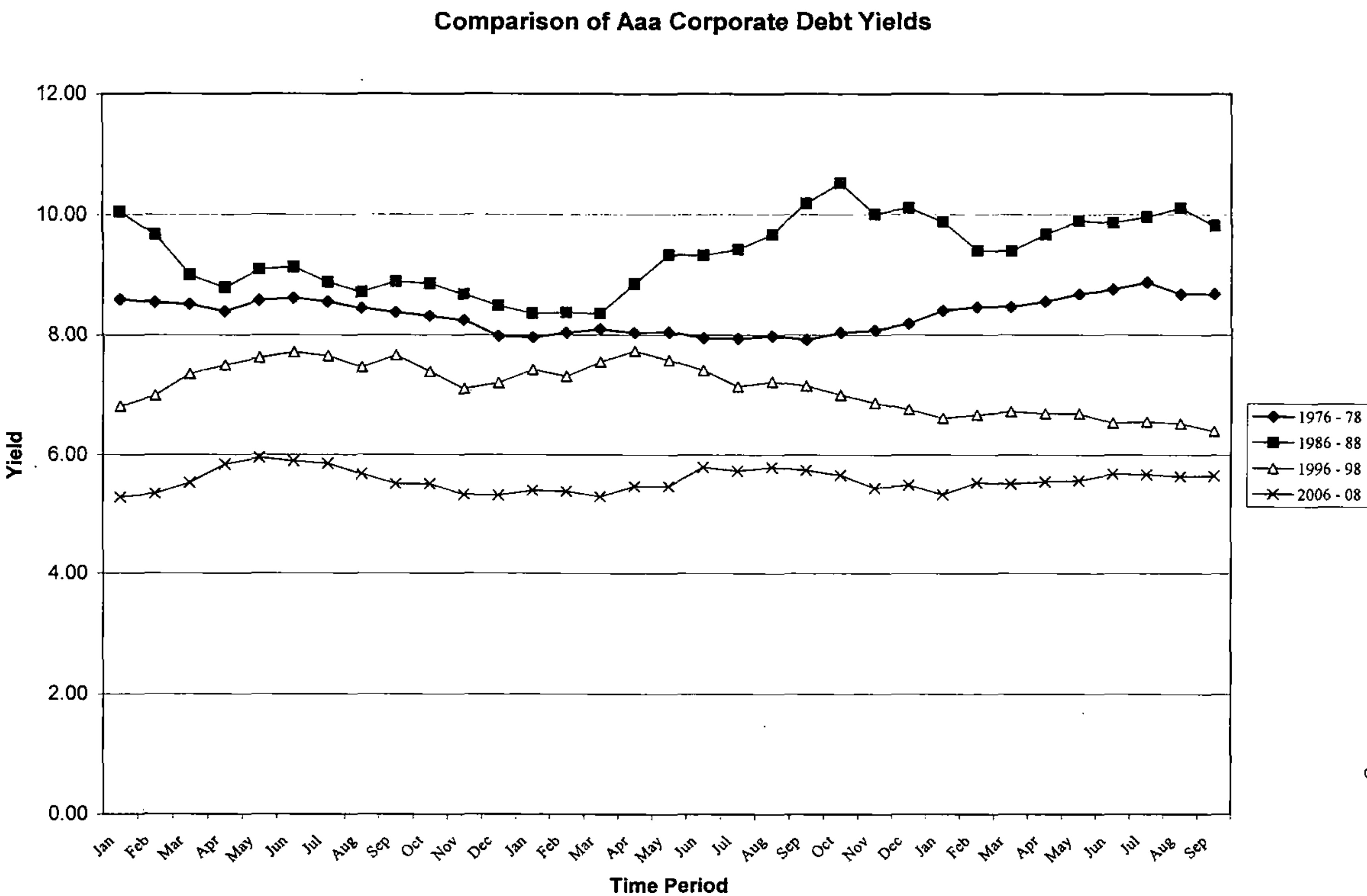
EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RR-16-D

Reference Equitable Statement No. 5, direct testimony of F. J. Hanley, page 20, lines 5 - 6. Provide all evidence at Mr. Hanley's disposal that verifies adding one hundred basis points (1.00%) to the estimated 2.26%, cost rate of commercial paper, results in forward looking cost rate of short-term debt for the Company.

Response:

Please refer to Equitable Statement No. 5, Page 20, lines 6-8, Equitable Exhibit 5A, Schedule 5, Page 1 of 10, and note 6 of that page, where it states that the basis of the short-term debt cost rate of Equitable Gas Company is company-provided information where the cost of Equitable Gas Company's demand notes payable to Equitable Capital Corp. is 100 basis points (1.00%) above the 3-month commercial paper rate as also shown on Equitable Exhibit 5A, Schedule 5, Page 1 of 10.



Source: St. Louis Federal Reserve Bank

OTS Exhibit No. 1-SR
Schedule No. 5
Page 1 of 2

Comparison Statistics of Aaa Debt Yields
For 33 Month Period
Sample Includes 1970's -2000's

1976 - 78		*1986 - 88*		*1996 - 98*		*2006 - 08*	
Mean	8.34	Mean	9.36	Mean	7.12	Mean	5.57
Standard Error	0.05	Standard Error	0.11	Standard Error	0.07	Standard Error	0.03
Median	8.40	Median	9.39	Median	7.15	Median	5.53
Mode	8.04	Mode	9.67	Mode	6.69	Mode	5.51
Standard Deviation	0.29	Standard Deviation	0.61	Standard Deviation	0.41	Standard Deviation	0.19
Sample Variance	0.08	Sample Variance	0.37	Sample Variance	0.17	Sample Variance	0.03
Kurtosis	-1.37	Kurtosis	-1.12	Kurtosis	-1.35	Kurtosis	-0.87
Skewness	-0.01	Skewness	-0.06	Skewness	-0.14	Skewness	0.26
Range	0.96	Range	2.16	Range	1.33	Range	0.66
Minimum	7.92	Minimum	8.36	Minimum	6.40	Minimum	5.29
Maximum	8.88	Maximum	10.52	Maximum	7.73	Maximum	5.95
Sum	275.12	Sum	308.75	Sum	234.96	Sum	183.85
Count	33.00	Count	33.00	Count	33.00	Count	33.00

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

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

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

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

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

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

The Logic of the CAPM

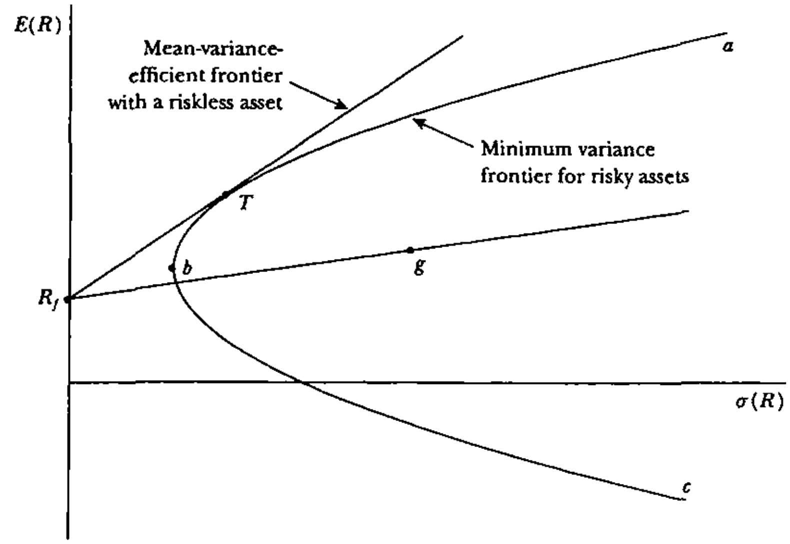
The CAPM builds on the model of portfolio choice developed by Harry Markowitz (1959). In Markowitz's model, an investor selects a portfolio at time $t - 1$ that produces a stochastic return at t. The model assumes investors are risk averse and, when choosing among portfolios, they care only about the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

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

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

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

Figure 1
Investment Opportunities



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Early Empirical Tests

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

Tests on Risk Premiums

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

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

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

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

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

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

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

Thus, the CAPM relation between expected return and beta,

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

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

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

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

is zero for each asset.

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

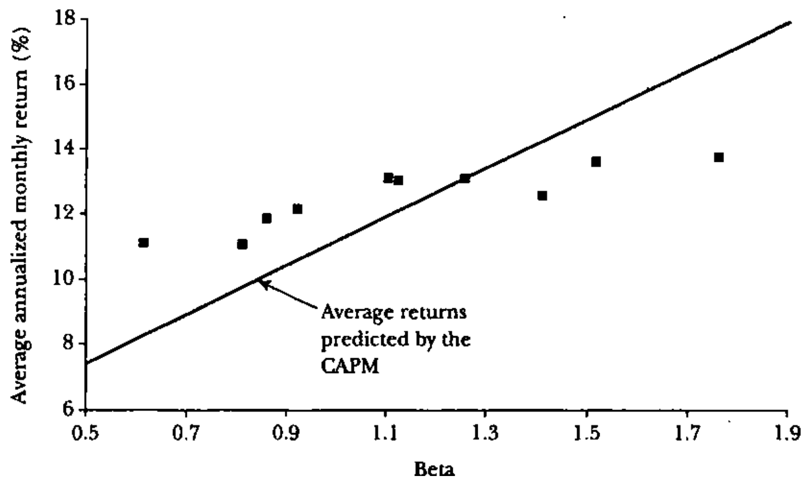
The evidence that the relation between beta and average return is too flat is confirmed in time-series tests, such as Friend and Blume (1970), Black, Jensen and Scholes (1972) and Stambaugh (1982). The intercepts in time-series regressions of excess asset returns on the excess market return are positive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

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

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

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

Figure 2
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



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

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

Testing Whether Market Betas Explain Expected Returns

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

In the framework of Fama and MacBeth (1973), one simply adds predetermined explanatory variables to the month-by-month cross-section regressions of

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returns on beta. If all differences in expected return are explained by beta, the average slopes on the additional variables should not be reliably different from zero. Clearly, the trick in the cross-section regression approach is to choose specific additional variables likely to expose any problems of the CAPM prediction that, because the market portfolio is efficient, market betas suffice to explain expected asset returns.

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

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

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

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

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

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

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

Recent Tests

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

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

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

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

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

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

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

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

Explanations: Irrational Pricing or Risk

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Market Proxy Problem

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

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

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

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

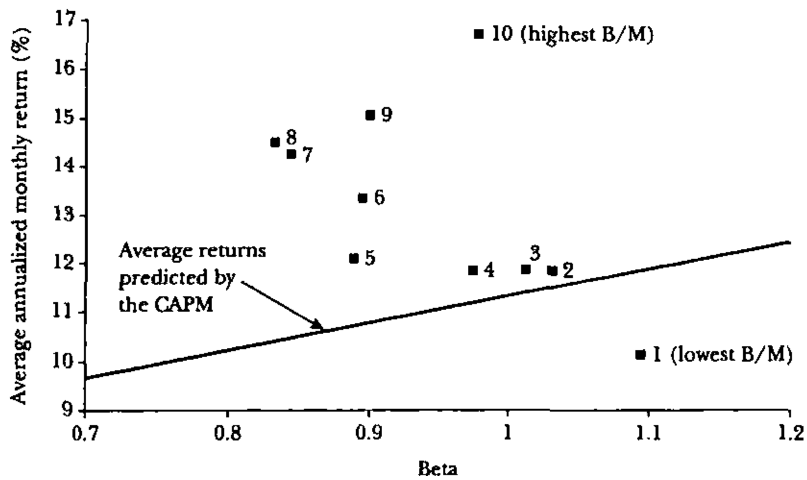
A major problem for the CAPM is that portfolios formed by sorting stocks on price ratios produce a wide range of average returns, but the average returns are not positively related to market betas (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1996, 1998). The problem is illustrated in Figure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

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

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

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

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



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

Conclusions

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

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a

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result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low.[7]

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

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

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

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OTS Statement No. 2
Witness: Debra Backer

11/19/08
NB6, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Direct Testimony

of

Debra Backer

Office of Trial Staff

Concerning:

OPERATING & MAINTENANCE EXPENSES

CASH WORKING CAPITAL

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

A. My name is Debra Backer. I am a Fixed Utility Financial Analyst in the Technical Division of the Pennsylvania Public Utility Commission's Office of Trial Staff (OTS). My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. This information is provided in Appendix A, which is attached to my testimony.

Q. PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS.

A. OTS was established by the legislature and is responsible for protecting the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of the ratepayers and the Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Based upon my review of Equitable Gas Company (Equitable or Company) base rate filing, I am recommending adjustments to the Company's proposed expenses for: Rate Case, Pension, Advertising, and adjustments to Equitable's Cash Working Capital Requirement.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments:

	Equitable Claim	OTS Recommended Claim	OTS adjustment
Rate Case Expense	$ 503,387	$ 363,232	($ 140,155)
Pensions Expense	$ 2,457,296	$ 0	($ 2,457,296)
Advertising Expense	$ 15,121	$ 2,481	($ 12,640)
Total O&M Adjustments			$ 2,610,091
Cash Working Capital	$ 11,335,335	$ 8,670,950	($ 2,664,385)

<u>**RATE CASE EXPENSE**</u>

Q. THE COMPANY HAS MADE A CLAIM FOR RATE CASE EXPENSE. WOULD YOU BRIEFLY EXPLAIN THE NATURE AND TYPE OF EXPENSES CLASSIFIED AS RATE CASE EXPENSE?

A. Rate case expense is the estimated costs that comprise a company's allowable claim to compile, present, and defend a request for a base rate increase before the Commission. The estimated costs that are typically found in a rate case expense claim include legal fees for outside counsel, fees to outside consultants and printing, collating and postal expenses.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE IN THIS PROCEEDING?

A. The Company's claim for rate case expense is $503,387 to be amortized over three years (Equitable Ex. III, A.17, p. 9, Part F).

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

A. No, I do not agree with the Company requesting the claim to be amortized over three years.

Q. HOW IS RATE CASE EXPENSE VIEWED?

A. Rate Case Expense is viewed as a recurring item. The Company has a history of filing base rate cases and has indicated they plan to file in the future.

Q. A KEY ISSUE CONCERNING THE RECOVERY OF RATE CASE EXPENSE IS WHETHER THE CLAIM SHOULD BE NORMALIZED OR AMORTIZED. WOULD YOU BRIEFLY DISCUSS THE CONCEPT OF NORMALIZATION?

A. Normalization is a ratemaking concept that describes the transformation of an operating expense that recurs at irregular intervals into a "normal" annual test year expense allowance. Normalization specifically addresses the prospective recovery of an ongoing expense that recurs sporadically. Allowed normalized expenses are no different than any other operations and maintenance (O&M) expense in that the company is given the opportunity to achieve full recovery.

Q. WOULD YOU EXPLAIN THE CONCEPT OF AMORTIZATION?

A. Amortization is an accounting procedure that extinguishes an atypical, nonrecurring expense over a pre-determined number of years by charging to operations, a pro rata share based on the selected amortization period. Although a claim for an un-recovered normalized expense would be disallowed if requested in a subsequent rate case, an amortization expense allowance could be claimed in succeeding rate cases as long as there is a remaining unamortized balance.

Q. IS THE COMPANY'S PROPOSED AMORTIZATION OF RATE CASE EXPENSE PROPER?

A. No. The Company's rate case expense claim should be normalized instead of amortized because it is an ongoing expense that recurs at irregular intervals. I also disagree with the recovery time frame of three years as discussed below.

Q. HOW DOES THE COMMISSION TREAT RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission views prudently incurred rate case expense as an ongoing, although recurring at irregular intervals, expense related to the rendering of utility service. As such, rate case expense is subject to normalization for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by computing the average number of months that expire between the filing dates of a Company's base rate case filings. The number of base rate case filings used to compute the average is a matter of judgment.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATED THIS CLAIM.

A. The Company's FTY claim for rate case expense in the current proceeding is $1,051,160 to be amortized over three years for an annual expense of $350,387 ($1,051,160 / 3). The Company included these costs plus one-fifth (1/5) of the expected costs to be incurred for the service life study to be filed in August 2008 and one-fifth (1/5) of the expected costs for the PUC management audit to commence in late 2008 ($765,000 amortized over 5 years = $153,000). Thus, the total amortization cost of these matters is $503,387 ($350,387 + $153,000) annually in the future test year.

Q. WHAT IS THE BASIS FOR THE COMPANY'S FUTURE TEST YEAR CLAIM OF $503,387?

A. The Company included estimated expenses for outside services in the areas of legal, rate of return, cost allocation, depreciation, and taxes (Equitable Ex. III, A-20). The Company requested an amortization period of three years for rate case fees and an amortization period of five years for the service life study and PUC management audit.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED THREE YEAR AMORTIZATION PERIOD?

A. Equitable witness, J.C. Mitchell states that the Company anticipates that the Company may file for another base rate increase in three years from the conclusion of this proceeding (OTS Ex. 2, Sch. 3).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend an allowance of $363,232.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend the total rate case expense be normalized over a period of five years. My recommendation results in a total FTY allowance of $363,232 (($1,051,160 / 5) + $153,000) for the 1/5 amortization of the service life study and management audit costs). This is a reduction to the Company's claim of $140,155 ($503,387 - $363,232).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED NORMALIZATION PERIOD?

A. My recommendation is based on a 60 month filing frequency or five-year normalization period, supported by the Company's filing history. Equitable claimed $259,551 in rate case expenses as of July 2008 and was requested to continue providing updates of invoices as they are incurred. If Equitable continues to update the rate case expense invoice amounts, I am not recommending adjustments to the total rate case expenses to be incurred at this time.

Q. WHY DID YOU RECOMMEND A FIVE YEAR NORMALIZATION PERIOD?

A. I recommended the longer normalization period because that is what the Company's irregular filing history supports. The Company has not filed a rate case in eleven and a half years or 138 months. The most recently filed rate case before this instant proceeding was February 28, 1997 at Docket No. R-00963858. The case prior to that was filed December 28, 1991 at Docket No. R-00912164, five years and two months (62 months) elapsed between the filing of rate cases. The average of the elapsed time frame between the most recent base rate cases filed is 100 months ((138 months + 62 months) / 2) or 8.3 years. The Company's requested three year recovery period is unsupported by the Company's historic tendencies and is speculative. A shorter recovery period would result in an unreasonable increase in rates and/or an over recovery of rate case expense in the event that the Company does not file in three years. The fact the Company has not filed for a base rate increase during the past 11 and a half year period demonstrates that a three year recovery period is not representative of Equitable's filing history. Using the average time elapsed between this rate case and the two prior rate cases results in a 100 month time frame. Although Equitable believes it may file for another rate case in three years, it is customary to use filing history, not the Company's future intentions, to determine the normalization period. The Company's irregular filing intervals supports the concept of normalization. OTS recommends using only a 60 month, or 5-year normalization period which is fair to both the ratepayers and the Company. Since I do not have a crystal ball, I must use the Company's filing history as the methodology for the time frame to normalize the rate case expense. The Company's filing history cannot support the 3-year time frame the Company is requesting but can justify the 5-year filing period that I am recommending.

PENSION EXPENSE

Q. WHAT IS A PENSION FUND?

A. A pension fund is a trust established to receive actual cash contributions by the Company for the benefit of its employees.

Q. WOULD YOU PROVIDE A BRIEF HISTORICAL OVERVIEW OF THE RATEMAKING TREATMENT FOR PENSION FUND CONTRIBUTIONS?

A. Yes. In the past, the proper regulatory treatment has allowed rate relief to utilities based on the actual cash contribution required to be paid into the pension fund. The contributions are based on an actuarial report which is prepared annually. Contained in the actuarial report is the actual present value of the fund (assets), as well as the anticipated liability of the fund. The liability is the amount determined by the actuaries to meet the benefits payable to the employees at any given time.

Q. WHAT IS THE PROPER RATEMAKING TREATMENT FOR PENSION FUND CONTRIBUTIONS?

A. The ratemaking claim for pension expense should be based on the Company's actual cash contributions to the pension funds. The pension fund is an entity separate from the Company, with its own assets, liabilities, revenues and expenses. However, the Company is required to make contributions to the fund, subject to minimum ERISA (Employee Retirement Income Security Act) requirements and maximum limitations of the Internal Revenue Code. These rules insure that the contributions are sufficient to meet future obligations and do not result in excessive asset levels.

The calculation utilizes a trended asset value intended to smooth out short term market fluctuations and results in a normal level of pension cost.

Q. PLEASE EXPLAIN HOW PENSION CONTRIBUTIONS ARE AFFECTED BY THE FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 87 (FAS 87).

A. FAS 87 requires a specific calculation to be used in determining pension expense. This amount is included in the financial statement of all companies. The purpose of FAS 87 is to allow the user of the financial statements to compare the pension plans and expenses among different companies. FAS 87 does not address funding requirements of the plan or the ratemaking treatment of the expense and should not be used for any purpose other than satisfaction of the requirements of FAS 87.

Q. PLEASE DISCUSS AND COMPARE THE TWO PENSION CONTRIBUTION CALCULATIONS THAT ARE REQUIRED TO BE MADE ANNUALLY.

A. There are two pension expense calculations that are computed annually by the Company's actuary: (1) FAS 87 pension expense and (2) the pension contribution that must be made to comply with IRS and ERISA rules.

The FAS 87 pension expense is accrued on the books of the Company and is adjusted at year end to the actuarially determined amount. There are no payments made to the pension plan for the FAS 87 pension expense since this expense does not represent the Company's pension liability but rather represents the amount that must be recorded on the Company's books in order to comply with Generally Accepted Accounting Principles (GAAP).

The second calculation performed by the actuary is the determination of the Company's annual maximum and minimum pension contribution computed in compliance with IRS and ERISA rules. It is these calculations that may require a payment into the pension plan.

The difference between the cash contribution and the book expense will be recorded on the books as a prepaid asset where the payment exceeds the expense, or as a liability if the payment is less than the expense.

Q. WHAT IS THE COMPANY ACTUALLY CONTRIBUTING?

A. For at least the past three years, Equitable has made no contributions to its Pension Fund and the Company's Actuarial Letter does not expect any contributions for the future test year (OTS Ex. No.2, Schedule 11).

Q. WHAT IS THE COMPANY'S CLAIM FOR PENSION EXPENSE?

A. Equitable's employee pension and benefit expense claim is $3,252,732 as presented in Equitable's Ex. III, A. 17, p. 11. The claim is split between Pensions and Benefits.

Q. WHAT IS YOUR RECOMMENDATION FOR PENSION EXPENSE?

A. I recommend the entire Pension Expense part be removed from the rate case filing based on the Company's contribution history and future intentions not to contribute.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the fact that Equitable has not been making annual contributions to its current pension fund and the expense is based on actual contributions made. Due to the fact that Equitable has not made any contributions, the allowable expense should reflect the actual contributions of $0 for Pensions and only include the Company's claim for benefits.

In response to Interrogatory OTS-RE-139-D, Equitable provided a breakdown of FERC Account 926, Employee Pensions and Benefits (OTS Ex. 2, Sch. 4). Equitable's pension expense claim for 2008 is $2,457,296. As a result, I recommended reducing the Company's Pensions and Benefits expense claim by $2,457,296.

<u>**ADVERTISING EXPENSE**</u>

Q. WHAT IS ADVERTISING EXPENSE?

A. Advertising Expense is the cost to develop media and utilize communication venues for marketing purposes.

Q. WHAT IS THE COMPANY'S CLAIM?

A. The Company's claim for Advertising Expense is $15,121 as shown in OTS. Ex. 2, Sch. 1, p. 3, Part C.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim includes costs to provide health and safety messages in magazines and miscellaneous publications; billing, rates and supply; and other programs. In addition, the Company's claim includes promotional advertising.

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

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an expense reduction adjustment of $12,640 to the Company's claim. My recommendation is to disallow sponsorships and other promotions the Company classified as other programs included in Account #913.0 Advertising expenses (OTS Ex. 2, Sch. 2).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. After reviewing the advertising program sample provided by the Company, such advertising is unnecessary for the provision of safe and reliable service. The advertising costs that I recommend to be disallowed stem from the representative advertising sample selected and provided by the Company (OTS Ex. 2, Sch. 1). This sample advertisement provided is focused on promoting the Company's image, and not on gas safety, energy conservation, energy education, or gas supply. Promotional advertising does not benefit the ratepayers and should not be paid by the ratepayers.

CASH WORKING CAPITAL (CWC)

Q. WHAT IS A CWC ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC is the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses and the receipt of revenue in payment of services rendered.

Q. HOW IS A CWC CLAIM CALCULATED?

A. CWC is calculated by a lead/lag study. A lead/lag study measures the differences in time between: (1) the time services are rendered until payment of those services is received; and (2) the time between when a utility has incurred an expense and the actual payment of the expense. Stated another way, the lead/lag study measures how many days exist on average between the midpoint of the service period and the date the payment is made.

Q. WOULD YOU EXPLAIN THE DIFFERENCE BETWEEN THE RATEMAKING AND ACCOUNTING CONCEPTS OF WORKING CAPITAL?

A. Yes. Outside the arena of utility ratemaking, accountants define working capital as the difference between current assets and current liabilities, which is a measure of a business' liquidity at a given point in time. On the other hand, the ratemaking concept defines CWC as the amount of capital that a utility requires to cover the gap or lag between the payment of operating expenses and taxes and the receipt of revenue from utility ratepayers.

Q. WHAT IS EQUITABLE'S CLAIM FOR CASH WORKING CAPITAL IN THIS PROCEEDING?

A. The total Company claim for CWC is $11,335,335 (Exhibit VI, Vol. 1, Item 18, p.2). The three components that comprise the Company's total CWC claim are as follows:

1.	CWC – O&M Expenses	$ 11,592,445
2.	Accrued & Prepaid Taxes	826,020
3.	CWC – Interest & Dividend	(1,083,130)
	TOTAL	$ 11,335,335

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on a lead/lag study of revenues and expenses for the twelve months ended December 31, 2007, updated for 2008 future test year expenses.

Q. WHAT IS YOUR RECOMMENDED ALLOWANCE FOR CWC?

A. I recommend a CWC allowance of $8,670,950. This represents a $2,644,385 reduction to the Company's claim.

Q. WHAT PROPOSED ADJUSTMENTS HAVE YOU INCLUDED IN YOUR RECOMMENDED REDUCTION OF $2,644,385 TO EQUITABLE'S CWC CLAIM?

A. First, I recommend reducing Equitable's revenue lag days from 49.29 to 47.29.

Q. WHAT IS INCLUDED IN EQUITABLE'S REVENUE LAG?

A. As shown below, Equitable's revenue lag consists of three parts (Ex. VI, Vol. 1, Item 18, p. 3):

1.	Revenue Collection Lag Days	29.20
2.	Service Lag Days	15.21
3.	Billing Lag Days	4.88
	Total Revenue Lag Days	49.29

I am recommending the Company's billing lag days included in the revenue lag be reduced from 4.88 to 2.88 lag days.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 2.88 BILLING LAG DAYS?

A. My recommendation to reduce the billing lag days is based on several reasons. First, in Equitable's prior base rate case at R-00963838 the billing lag days were only 4 days (OTS Ex. 2, Sch. 5). Equitable's witness Henry J. Rettger states in his testimony on page 3, line 4, that the Automated Meter Readers (AMR) program allows the Company to process accurate and timely reads. With the increase in technology using AMR that Equitable implemented in 2006, the lag days should have decreased, not increased, since the last case. Over eleven years ago when Equitable filed a base rate case Equitable only claimed 4 billing lag days and now with more accurate and timely technology, the Company is claiming a larger 4.88 billing lag. The increase in lag days is not logical. I recommend Equitable reduce the billing lag to show a more accurate representation of how billing is more efficient now with Automated Meter Readings.

Second, an examination of each component of the billing process does not support the Company's claim. The Company provided a breakdown of the 4.88 days and claims on Days 1-3 the meters are read; Day 3 the readings are loaded and generate consumption and audit exceptions; Day 4 audit exceptions are worked; and Day 5 bills are sent to the printer and mailed (OTS Ex. 2, Sch. 6). The Company claims 99% of their meters are read electronically using AMR Radio Frequency Technology and only 1% are read by a meter reader (OTS Ex. 2, Sch. 7). The Company also claims the information is loaded into the system the same day or the following day. The Company claims LDC meters are generally read one day in advance of the billing day in the event of equipment failure, weather, or other unplanned event. This statement proves three days to read the bills is excessive and that actually only two days at most are necessary. Day 4 is used to work Audit exceptions. In the same response, the Company claims there are approximately 1,000 audit exceptions created per month from the 12,000 – 18,000 meters. A whole day to hold all the bills for 5.5% (1,000 audits / 18,000 meters read) to 8.3% (1,000 audits / 12,000 meters read) audit exceptions of the total bills is excessive and not considering the other 91.7% (100% - 8.3%) to 94.5% (100% - 5.5%) whose accounts did not create the audit exceptions. As a result, I recommend that two days should be removed from the collection lag of 4.88 for a more accurate representation of the billing lag of 2.88 days.

Lastly, I compared Equitable's billing lag days to other utility's billing lag days.

Q. WOULD YOU IDENTIFY THE BILLING LAG IN SOME OTHER UTILITY CASES?

A. Yes. The following table presents the billing lags for a sample of other utilities:

Company	Docket	Billing Lag
PG Energy	R-00061365	2.88 days
Columbia Gas	R-2008-2011621	2.21 days
Duquesne Light	R-00061346	2 days
Aqua	R-00072711	2 days
Met Ed	R-00061366	1.5 days
Penelec	R-00061367	1.5 days

Q. WHAT DOES YOUR COMPARISON SHOW?

A. This comparison clearly indicates that Equitable's billing lag of 4.88 is higher than other utility companies and supports my recommendation of 2.88.

Q. ARE THERE OTHER CHANGES YOU ARE RECOMMENDING TO THE CWC LAG CALCULATIONS?

A. Yes. I am also recommending corrections to the lag calculations of Other O&M Expense and the Injuries and Damages Insurance.

Q. WHAT CHANGES ARE YOU RECOMMENDING BE MADE TO THE LAG CALCULATION OF OTHER O&M EXPENSES?

A. I recommend the Company claim of 35.47 lag days for other O&M expenses be increased by 1.37 lag days to 36.84.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am recommending the lag days be increased in order to recognize a reporting error identified by the Company in Other O&M – OSS worksheet for C Leon Sherman & Associates (Equitable Ex. VI, Vol. 1, Item 18, p. 17). In a data request response, the Company admitted the period covering May 2007 was actually paid June 28, 2007, not May 22, 2007, as the worksheet implies (OTS Ex. 2, Sch. 8). When the correct payment date is used, the lag days increase from 6 days to 43 days and the dollar days increase from $91,148 to $653,213. This changes the Other O&M – OSS Grand Total amount to $296,959,194 for the Dollar Days, (column G). Adding the Other O&M expenses lag days with the Company's correction would now be 36.84 and would be the amount reflected on the summary page Ex. VI, Vol. 1, Item 18, p. 1, Column 5.

Q. IS THERE ANOTHER CORRECTION YOU ARE MAKING TO CWC?

A. Yes. I am correcting two areas of the Injuries and Damages Insurance in Ex. VI, Vol. 1, Item 18, p. 19.

Q. WHAT IS YOUR FIRST CORRECTION TO INJURIES AND DAMAGES INSURANCE?

A. First, I corrected the Property Insurance calculation. In response to an OTS Interrogatory, the Company explained that the property insurance premiums for Equitable Gas were $158,512.30 for November 1, 2006 - November 1, 2007 and $130,634.57 for November 1, 2007 – November 1, 2008 (OTS Ex. 2, Sch. 9, Part E). The Company is trying to claim both insurance premiums although they cover a two year period. The Company needs to remove the second property insurance claim covering November 1, 2007 – November 1, 2008 for an expense amount of $130,635 resulting in ($23,383,588) dollar days.

Q. WHY IS IT APPROPRIATE TO REMOVE THE SECOND PROPERTY INSURANCE PAYMENT?

A. A lead/lag study measures receipts and payments for a single year. The inclusion of the second renewal payment overstates the CWC claim.

Q. WHAT IS YOUR NEXT CORRECTION TO INJURIES AND DAMAGES INSURANCE?

A. My next correction is in the punitive claim. The Company claims the paid dates on the spreadsheet were transposed possibly due to the use of the European manner by which dates are expressed (OTS Ex. 2, Sch. 9, Part J). Punitive dates should have been 8/11/07 – 8/11/08, not 11/8/07 – 11/8/08. This correction changes the mid-point of the period to 2/9/08, not 5/9/08 as the Company claimed. By following the changes, the days lags are now (182) in lieu of (252) and the dollar days are for the first punitive claim are ($3,089,632) in lieu of ($4,277,839) resulting in a difference of $1,188,207 and the second punitive claim dollar days of ($2,858,492) in lieu of ($3,958,000) for a difference of $1,099,508. The two corrections for Punitive result in an adjustment of $2,287,715.

Q. WOULD YOU PLEASE SUMMARIZE YOUR INJURIES AND DAMAGES INSURANCE CORRECTIONS?

A. Yes. I removed the second property insurance claim expense claim of $130,635 with a corresponding dollar day amount of ($23,383,588). I also updated Punitive with the correct dates the Company provided for a total adjustment of $2,287,715. The Total Injuries and Damages Insurance Dollar Days amount was ($277,214,753) and after the corrections is ($251,543,450). The total amount of Injuries and Damages Insurance expense is now $1,552,113 ($1,682,748 total in rate filing - $130,635 for the second year insurance premium). The weighted average lag days were (164.74) and with the corrections should be (162.07) calculated as the new total dollar days of ($251,543,450) / $1,552,113.

Q. WHAT IMPACT DOES THE CWC CHANGES AND CORRECTIONS HAVE ON THE CWC REQUIREMENT FOR EQUITABLE?

A. Equitable is claiming a total cash working capital requirement of $11,335,335 for the twelve months ended December 31, 2008 (Ex. VI, Vol. 1, Item 18, p. 2). After inputting the corrections and changes, Equitable's total cash working capital requirement would be $8,670,950 resulting in a $2,644,385 reduction to CWC (OTS Ex. 2, Sch. 10).

Q. DOES YOUR RECOMMENDED CWC ALLOWANCE OF $8,670,950 REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes and rate base must be consistently brought together in the ALJ's Recommended Decision and again in the Commission's Final Order. This process, which is know as "iteration", effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

Q. COULD YOU PLEASE SUMMARIZE YOUR ADJUSTMENTS?

A. The following table summarizes my adjustments:

	Equitable Claim	OTS Recommended Claim	OTS adjustment
Rate Case Expense	$ 503,387	$ 363,232	($ 140,155)
Pensions Expense	$ 2,457,296	$ 0	($ 2,457,296)
Advertising Expense	$ 15,121	$ 2,481	($ 12,640)
Total O&M Adjustments			$ 2,610,091
Cash Working Capital	$ 11,335,335	$ 8,670,950	($ 2,664,385)

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

PROFESSIONAL AND EDUCATION EXPERIENCE

DEBRA J. BACKER

Professional Experience

December 2005 to Present: Office of Trial Staff, Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania.

Fixed Utility Financial Analyst – Responsible, primarily, for the review of operating and maintenance expense and cash working capital as part of the evaluation and recommendation process for utility base rate and purchase gas costs filings.

November 2004 to December 2005: Pennsylvania Department of Labor and Industry, Harrisburg, Pennsylvania.

Unemployment Compensation Tax Technician – Responsible, primarily, for reviewing and maintaining employer's accounts and ensuring the accounts were in compliance with the Pennsylvania Unemployment Compensation Law and making proper adjustments necessary to ensure compliance.

Education

Edinboro University of Pennsylvania, Edinboro, Pennsylvania
Bachelor of Science; Major in Business Administration, 1993

Attended NARUC Rate School, San Diego, CA

Testimony submitted

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

PPL Electric Utilities Corporation, Docket No. R-00072155
PPL Gas Utilities Corporation, 1307(f) proceeding, Docket No. R-00072333
Pennsylvania-American Water Company, Docket No. R-00072229
West Penn Power Company, Docket No. P-00072342
TESI, Treasure Lake Water Division, Docket No. R-00072493
TESI, Treasure Lake Sewer Division, Docket No. R-00072495
Columbia Gas of Pennsylvania, Inc, Docket No. R-2008-2011621

OTS Exhibit No. 2
Witness: Debra Backer

11/19/08 HBG, PA
RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Direct Testimony

of

Debra Backer

Office of Trial Staff

Concerning:

OPERATING & MAINTENANCE EXPENSES

CASH WORKING CAPITAL

Docket No. R-2008-2029325
Item: OTS-RE-84-D
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-84-D

Reference Exhibit VI, Annual Report Pennsylvania Division, p. 33-a, Schedule 405.

A. Reference Account #880.0, Other Expenses in the amount of $1,288,739. Provide a breakdown of items included in this expense account and the corresponding dollar amounts.

B. Reference Account #903.0, Customer Records & Collections Expenses in the amount of $9,500,849. Provide what items are included in this account and the corresponding dollar amounts.

C. Reference Account #913.0, Advertising Expenses in the amount of $24,121. Describe the nature and purpose of the Advertising Expense and provide examples of such advertising placed in each of the venues listed:

1. Newspaper
2. Radio
3. Magazines & Miscellaneous
4. Bill Inserts & Brochures

D. For calendar year 2008, provide a copy of one of the Company's published advertisements from each of the categories (Public health & Safety, Billing, Rates, Supply, etc. and Educational Institutional Programs), and identify what venue the advertising was placed and the cost of the sampled advertising effort.

E. Reference Account #925.0, Injuries and Damages in the amount of $4,197,695. Provide a breakdown of items included and the corresponding dollar amounts.

F. How does Account #925.0 Injuries and Damages differ from Account #228.8 Accumulated Provision for Injuries and Damages?

G. Reference Account #930.1, General Advertising Expenses in the amount of $54,602. Describe the nature and purpose of the Advertising Expense and provide examples of such advertising placed in each of the venues listed:

1. Newspaper
2. Radio
3. Magazines & Miscellaneous
4. Bill Inserts & Brochures

H. Reference Account #930.1, General Advertising Expenses in the amount of $54,602 and explain how this account differs from Account #913.0, Advertising Expenses in the amount of $24,121.

I. Reference Account #930.2, Miscellaneous General Expenses in the amount of $2,980,851. Provide a description of items in this account and the corresponding dollar amounts.

J. Reference Account #931.0, Rents, in the amount of $5,032,090. Provide a description of items rented and the corresponding dollar amounts.

K. Explain what caused Rents to increase by $1,135,621 from the previous year.

Response:

In reference to Exhibit VI, Annual Report Pennsylvania Division, p. 33-a, Schedule 405:

A. Account #880.0, Other Expenses in the amount of $1,288,739 includes the following:

• Safety & Environmental Expenses	$702,136
• Labor & Fringes	$443,366
• Materials & Supplies	$83,645
• Outside Services	$76,881
• Employee Expenses	$10,409
• Training & Seminars	$9,311
• Vehicle Expenses	$1,878
• Utility Expenses	$99
• Postage	$54
• Telecom Adjustments	($49,448)
• Other Misc.	$10,408

B. Account #903.0, Customer Records & Collections Expenses in the amount of $9,500,849 includes the following:

• Labor & Fringes	$4,917,339
• Call Center & Collection Services	$2,675,451
• Postage/Mailing Services	$1,387,473
• Telecom Expenses	$200,320
• Metering Services	$145,066
• Vehicle Expenses	$136,155
• Materials & Supplies	$15,648
• Employee Expenses	$2,435
• Other Misc.	$20,962

C. Expenses captured in Account #913.0, Advertising Expenses are costs related to broader corporate sales and marketing initiatives. Of the $24,121 of expenses in this account, only $15,121 was included in the rate case filing.

Please see attached files for an example of such advertising.

D. Please see attached files for examples of the Company's published advertisements and bill inserts for 2008.

E. Account #925.0, Injuries and Damages in the amount of $4,197,695 consists of expenses related to third party injuries and damages totaling $3,947,279 and expenses related to workers' compensation matters totaling $250,416.

F. Account #925.0 Injuries and Damages is an Administrative & General Operations Expenses account on the Company's Operating Statement which is comprised of expenses related to third party injuries and damages and expenses related to workers' compensation matters, and Account #228.8 Accumulated Provision for Injuries and Damages is the related account on the Company's Balance Sheet which is comprised of the Company's reserves for such matters.

G. Account #930.1, General Advertising Expenses in the amount of $54,602 includes the following expenses.

1.	Newspaper	$1,866
2.	Radio	
3.	Magazines & Miscellaneous	$43,277*
4.	Bill Inserts & Brochures	$9,459

*Included in this amount is $24,132 of outreach related costs incurred for the LIHEAP service program. Also included in this amount is $13,587 for PR Newswire releases, which is not included in the rate case filing.

H. Account #930.1, General Advertising Expenses in the amount of $54,602 is reserved for expenses related to general and customer service related advertising expenses, such as bill inserts and direct customer communications. Whereas, Account #913.0, Advertising Expenses in the amount of $24,121, captures sales and marketing advertising expenses and broader corporate communication .

I. Account #930.2, Miscellaneous General Expenses in the amount of $2,980,851 includes the following expenses:

• Board of Directors Expenses	$2,319,870
• Corporate Entertainment	$371,763
• American Gas Association Dues	$151,064*
• Annual Report Fees	$120,905
• Website Fees	$11,905
• Corporate Dues (PRMPC)	$5,344*

Docket No. R-2008-2029325
Item: OTS-RE-84-D
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

*Of the $2,980,851 in Account #930.2, Miscellaneous General Expenses total, the denoted items totaling $156,308 were included in the rate case filing.

J. Account #931.0, Rents, in the amount of $5,032,090 includes the following expenses:

- Rents included in the rate case filing $3,258,962*
  Please refer to Exhibit III, Item 53.53, III A. 23 for further details of these expenses.
- Corporate Rent – PA Facilities $1,744,905
- Corporate Office Equipment Rentals $28,223

*Of the $5,032,090 in Account #931.0, Rents total, the denoted items totaling $3,258,962 were included in the rate case filing.

K. Rents increase by $1,135,621 from 2006 to 2007 primarily due to general facility increases company-wide.

They bring the heat. They energize families. They're efficient.

The Pens? Sure.

Natural gas water heaters? Absolutely.

For information on how natural gas water heaters can save you money, call Equitable Gas at 412-395-2085.

EQUITABLE GAS

Delivering Everyday Excellence™

Docket No. R-2008-2029325
Item: OTS-RE-136-D
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: *OTS-RE-136-D*

Reference Equitable's response to OTS-RE-84-D, Part C, Advertising Expenses.

A. Where in the filing is the $15,121 advertising expense included?

B. Were all the samples attached to the Company's response included in the $15,121 dollar amount?

C. Identify the sample ads by which venue the ad was used for, i.e. newspapers, magazines, bills inserts, brochures and the associated dollar amounts.

Response:

Reference Equitable's response to OTS-RE-84-D, Part C, Advertising Expenses.

A. The $15,121 of advertising expense captured in FERC account 913000 is included in Exhibit III Item 53.53 III A-25 in the original filing as part of the total 2007 advertising expenses.

B. The sample included in the Company's response was a published advertisement. This advertisement was published twice in a magazine/other program at a cost of $5,000 each, totaling $10,000. Other samples included in the $15,121 total advertising expenses included sponsorships and other promotions, in which samples were not available.

C. Identify the sample ads by which venue the ad was used for, i.e. newspapers, magazines, bills inserts, brochures and the associated dollar amounts.

Magazines and Miscellaneous	
a. Public Health & Safety	250
b. Conservation	-
c. Billing, Rates, Supply	2,231
d. Educational institutions	-
e. Other programs	12,640
f. Total	$ 15,121

OTS Exhibit No 2
Schedule 3

Docket No. R-2008-2029325
Item: OCA-IX-2
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-IX-2

With reference to the response to OTS-RE-89-D:

a. Please explain why the Service Life Study and the PUC Management Audit are proposed to be amortized over 5 years while 3 years is used for rate case expense; and

b. How frequently are service life studies conducted? When will the next service life study be conducted for the Company?

Response:

a. The service life study and PUC Management Audit are proposed to be amortized over five years as the service life study and PUC Management Audit are generally conducted every five years. The rate case expenses are being amortized over three years as it is anticipated that the Company may file for another base rate increase in three years from the conclusion of this proceeding.

b. As noted above, the service life study is completed every five years. The next service life study is to be filed on or before October 31, 2008.

Docket No. R-2008-2029325
Item: OTS-RE-139-D
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-139-D

Reference Ex. III, A-18, p. 5, Acct. 926, *Employee Pensions and Benefits.*

A. Provide a detailed breakdown of the Pensions and Benefits entries included in this account. Include the dollar amounts for the years ending 2006, 2007 and 2008.

B. Provide a breakdown of the amounts capitalized in rate base for the same items listed in your response to Part A above. In your response, show the amounts allocated to the expense amount and to rate base.

Response:

Reference Ex. III, A-18, p. 5, Acct. 926, Employee Pensions and Benefits.

A. Please see attached schedule for details related to the Pensions and Benefit entries included in FERC account 926, Employee Pensions and Benefits.

B. As noted in the Company's response to OTS-RE-75-D, FERC Account No. 926, Employee Pension and Benefits, includes amounts expensed for employee compensation under the Company's Short-Term Incentive Plan (STIP). Amounts capitalized in rate base in FERC Account No. 107, "Construction Work in Progress" for such incentives totaled $726,064, $990,838, and $990,838 for the years ending 2006, 2007 and 2008. No other items recorded in FERC Account No. 926 have related amounts capitalized in rate base.

FERC Account 926000 Details

DESCRIPTION	2006* AMOUNT	2007 AMOUNT	2008** AMOUNT
Survivor Payment	-	25,000	25,000
Tuition Reimbursement	57,195	52,567	52,567
Pension-FAS 87/88/106	2,606,936	2,457,296	2,457,296
Short Term Incentive Plan (STIP)	3,142,195	3,320,838	3,553,044
Other Employee Fringes	132,201	31,873	31,873
Stock Awards	590,185	-	-
Fringe Benefits related to acct 920	1,443,750	-	-
TOTALS	**7,972,462**	**5,887,574**	**6,119,780**

* NOTE 1: The 2006 amounts for stock awards and fringe benefits related to account 920 were not adjusted in a manner consistent with the historic and future test years. Stock awards were excluded from the historic and future test years and fringe benefit costs related to account 920 were reclassed from account 926 in the historic and future test years.

**NOTE 2: The 2008 future test year amounts were estimated to approximate the 2007 amounts, with the exception of the Short Term Incentive Plan expenses which are expected to increase with the projected annual wage increases.

OTS Exhibit No. 2
Schedule 5

Docket No. R-00963858
Item: OTS-RE-46
Respondent: Stuart McDaniel
Position: Senior Vice President

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-46

Isolate and explain why the billing lag increased from four days, in the previous base rate proceeding, to seven days in this proceeding for the Large Volume customers.

Response:

The billing lag for large volume customers should be four days and not seven days as shown in the study. The calculation of the Company's working capital allowance will be updated during the pendency of this proceeding and this change will be reflected at that time.

Docket No. R-2008-2029325
Item: OTS-RE-16-D
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-16-D

Reference Exhibit VI, Vol. 1, Item 18, p. 3 of 32, Revenue Lag.

A. Breakdown the billing lag of 4.88 in full detail by days for each segment of the billing process. For example, how are the meters read (electronically, meter reader), how long it takes for the reading to get into the system, when the bills are printed, when the bills are mailed.

B. Provide a sample copy of a residential bill. Delete the customer's name, account number and address from the bill.

C. Breakdown daily cash collections by days from when they are received until they are logged into the books?

Response:

A. The billing lag is defined as the number of days from the meter reading date to the date the bill is placed in the mail. The following table represents the breakdown of the billing lag for a residential customer. The actual meter reading dates, weekends, holidays, and the commercial billing cycles are what decreases the billing lag from a maximum of 5 days to 4.88 days.

Day	Process
Day 1-3	• Meters are read
Day 3	• Meter reads loaded into CIS • CIS process reads and generate consumption • CIS creates audit exceptions
Day 4	• Audit exceptions are worked
Day 5	• Bills sent to the printer • Bills placed into the mail

B. Attached please find an example of a residential customer's bill.

C. The process of daily cash collections consists of receiving payments from customers, having those payments deposited in a bank account and posting the cash receipt to the customer's account in the CIS system. Please refer to the table below for a breakdown of daily cash collections by days:

Payment Type	**Percentage of Total Payments Received**	**Payments are received and posted to the customer's account in CIS**
Lock Box and Auto-debit payments	85%	Same day (1 day)
On-line payment vendors, credit card payment vendors	15%	Next day (2 days)

Docket No. R-2008-2029325
Item: OTS-RE-91-D
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-91-D

Reference OTS-RE-16-D response.

A. As stated in the original question, explain how meters are read (i.e. electronically, meter reader going to the house) and provide the percentage of bills read that way.

B. Explain why after the meters are read the information is not loaded and bills generated the same day or the following day.

C. Are meter readings loaded into CIS by manually typing them in or can they be automatically downloaded from the meter reading equipment?

D. What is the rational for holding back all bills from being mailed due to an audit exception?

E. Approximately how many bills are read on Days 1-3?

F. Regarding your response to Part D above, out of the number of bills read on Days 1-3, on average how many readings create an audit exception?

Response:

A. The manor in which the meters are read does not impact the billing lag. Nonetheless, the majority of the LDC meters are read electronically using Automatic Meter Reading (AMR) RF technology. The percentage of meters read by Read type are approximately as follows:

Read Type	Percent
Electronically	99 %
Meter Reader	1%

B. After the meters are read, the information is loaded into the CIS system the same day or the following day, the LDC meters are generally read one day in advance (Day 2) of their "billing day" (Day 3) (the day the Reads must be loaded into the CIS system for billing). This is for operational reasons in the event of equipment failure, weather, or some other unplanned event that would prohibit the reading of a whole Read Control which can be up to 12,000 – 18,000 meters. This practice is consistent with other LDCs across the country.

C. Meter readings for the LDC are transferred from the meter reading equipment to the CIS system through an upload file.

D. The procedure used for billing as described in the response OTS-RE-16-D is driven by the programming and configuration of the CIS system.

E. All of the LDC meters are read on Days 1,2, or 3.

F. Audit exceptions are created for other reasons beyond only bad meter reads. 1,000 audit exceptions are created per month.

Docket No. R-2008-2029325
Item: OTS-RE-23-D
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-23-D

Reference Exhibit VI, Vol. I, Item 18, p. 17, Other O&M –OSS.

A. Provide a list of items included in this expense account.

B. Reference C Leon Sherman & Associates PC, May 2007. Explain why the May transaction was paid before the end of the period covered. Provide the invoice and check supporting this transaction.

Response:

A. Items included in Other O&M –OSS
- Call Center and Collection Services
- Mainline and Service Line Works
- Leak Detection Survey and Field Credit & Collection
- Legal

B. The C Leon Sherman & Associates PC, May 2007 transaction was actually paid on 6/28/2007. Please see attached for the invoice and the payment records.

Docket No. R-2008-2029325
Item: OTS-RE-25-D
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-25-D

Reference Exhibit VI, Vol. 1, Item 18, p. 19, Injuries and Damages Insurance.

A. Provide a similar schedule with the same expenses for calendar years 2005 and 2006 showing the periods covered, date paid and the amount of the expense.

B. Provide an explanation and invoices for the Crime expense.

C. Provide invoices and checks to support the property insurance claims.

D. Provide an explanation as to why the property insurance period coverage from 11/2006 – 11/2007 was not paid in 2006.

E. Is the property insurance plan period 11/2007 – 11/2008, expense amount of $130,635, the renewed insurance policy of the 11/2006 – 11/2007 expense amount of $158,512.30? If they are different policies, explain the difference.

F. Reference the Broker Fees. Provide an explanation of the Broker Fees and the payment plans involved.

G. Provide invoices and checks to support the Broker Fee expense amounts.

H. Explain why the fees cover two years, i.e. 2 fees for 9/1/2006 – 9/1/2007, 2 fees for 9/1/2007 – 9/1/2008, and 1 fee for 8/11/2007 – 8/11/2008.

I. Explain the Broker Fee 8/11/2007 – 8/11/2008 for $38,623 and explain why this amount is 273% more than the other broker fees.

J. Reference Punitive. Provide invoices and checks supporting this expense and explain why this expense was paid 8/31/2007, two months before the coverage period of 11/8/2007 – 11/8/2008.

Response:

A. Please see the attached schedule.

B. The Crime coverage is also known as the Fidelity Bond, which is required on the Employee Retirement Income Security Act (ERISA) - employee benefit programs. The invoice is attached. Note that due to the size of the benefit plans, we were required to increase the bond from $2 million to $3 million. This occurred in November 2007.

C. There were no property insurance claims.

D. The property insurance policy that renewed effective November 1, 2006 and continuing through November 1, 2007 was invoiced on December 28, 2006 and paid on January 31, 2007.

E. The property insurance premiums for Equitable Gas were as follows:
- November 1, 2006-November 1, 2007 was $158,512.30
- November 1, 2007- November 1, 2008 was $130,634.57

F. We use two insurance brokers to place our insurance programs. The breakout is as follows:
- Marsh is used for:
  - Directors & Officers, Fiduciary and Fidelity(Crime)
  - Property
  - Surety
- McGriff, Seibels and Williams is used for:
  - Excess Liability program
  - Excess Workers' Compensation
  - Automobile Liability

G. See attached invoices from both Marsh and McGrif

H. The placements that Marsh handles occur throughout the year and for that reason we pay them quarterly. The McGriff placements all renew on August 11th and for that reason we pay the fee in a single payment after the placements are bound.

I. As described in H above, the McGriff fee of $38,632 is for the entire year as compared to the quarterly Marsh fees of $14,337.50, which equal $57,350 on an annualized basis.

J. Note the punitive damage coverage is placed simultaneously with the excess liability coverage, which renews on August 11th. The dates on the spreadsheet were transposed possibly due to the use of the European manner by which dates are expressed: for example 11/8/2007 is actually August 11, 2007. The payment date of 8/31/2007 is after the 8//11/2007 placement date.

EQUITABLE GAS COMPANY - per OTS
SUMMARY OF CASH WORKING CAPITAL LEAD/LAG STUDY AT PRESENT BASE RATES
TWELVE MONTHS ENDED DECEMBER 31, 2008

OTS Exhibit No. 2
Schedule 10

Cost Category	Pro Forma Expense	Daily Requirement	Revenue Lag Days		Expense Lag Days		Net Lag Days	Working Capital Requirement
(1)	(2)	(3)	(4)		(5)		(6)=(4)-(5)	(3)*(6)
OPERATING EXPENSES								
Gas Purchased	359,315,773	984,427	47.29	(a)	45.91		1.38	1,361,425
Payroll	24,095,087	66,014	47.29		17.09		30.20	1,993,621
Employee Benefits	7,069,423	19,368	47.29		11.03		36.26	702,322
Corporate Services	15,990,000	43,808	47.29		14.71		32.58	1,427,241
Injuries & Damages Insurance	4,803,788	13,161	47.29		(162.07)	(b)	209.36	2,755,400
Uncollectibles	25,049,825	68,630	47.29		47.29		-	-
Other O & M Expense	28,100,026	76,986	47.29		36.84	(c)	10.45	804,508
Total Operating Expense	464,423,924							
Depreciation & Amortization	23,471,055							
TAXES OTHER THAN INCOME	2,185,866	5,989	47.29		(66.05)		113.3	678,736
INCOME TAXES								
Current -Federal	(3,182,873)	(8,720)	47.29		36.50		10.8	(94,091)
Current - State	(1,009,313)	(2,765)	47.29		51.58		(4.3)	11,849
Deferred - Federal & State	8,545,747							
Investment Tax Credit	(5,529)							
INTEREST ON DEBT	16,972,650	46,500	47.29		72.58		(25.3)	(1,176,131)
PA Sales and Use Taxes	6,287,006	17,225	47.29		35.33		11.96	206,070
TOTAL CASH WORKING CAPITAL REQUIREMENT								8,670,950

(a) Billing lag reduced by 2 days
(b) Injuries and Damages Insurance reduced due to Equitable responses to OTS interrogatories
(c) Other O&M expense lag updated due to Equitable responses to OTS interrogatories

Docket No. R-2008-2029325
Item: OTS-RE-68-D
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-68-D

Provide the following:

A. A copy of the 2005, 2006, and 2007 actuarial reports for all Pensions and Post Retirement Benefits (OPEB);

B. All actuarial letters supporting the estimates for 2008;

C. The amount of the Medicare Part D subsidy from the government for providing Post Retirement benefits and provide supporting documentation if this amount is deducted from the HTY expenses;

D. Provide the terms of the funding policy for benefits.

Response:

A. Please see attached copies of the 2005, 2006, and 2007 actuarial reports for Pensions and Post Retirement Benefits.

B. Please see attached copy of the actuarial letters supporting the estimates for 2008 Pension and Post Retirement Benefits costs.

C. The Company does not receive a Medicare Part D subsidy from the government for providing Post Retirement benefits and as such, no such amount was deducted from the HTY expenses reported.

D. The Company's policy is to fund the Pension plan to a level that at least meets the minimum ERISA funding requirements. Postretirement benefit plans are unfunded; therefore, the Company reimburses the third-party service provider for claims paid as part of the Post Retirement Benefits process.

Watson Wyatt
Worldwide

March 20, 2008

Mr. Michael Klaum
Financial Specialist
Equitable Resources, Inc.
225 North Shore Drive
6th Floor
Pittsburgh PA 15212-5861

'Via Email'

Subject: SFAS 87 & SFAS 88 Estimated Expense for FY2008

Dear Mike:

As requested, we have determined the total qualified and nonqualified FY2008 SFAS 87 expense to be $529,402 and have estimated the SFAS 88 expense to be $505,000.

The enclosed Table 1 presents a summary of the SFAS 87 and estimated SFAS 88 expense organized by business unit for FY2008. Table 2 presents the components of SFAS 87 expense and is also organized by business unit.

Please note that the estimated SFAS 88 expense shown in Table 1 is the same as shown in our August 1, 2007 letter. Actual FY2008 SFAS 88 settlement results will depend upon a number of factors that may not be known with certainty until the end of the fiscal year. These factors include investment performance for the year, lump sum payments and the interest rate environment at year end. Given how asset returns are unfolding, you may consider accelerating FAS 88 accruals this year to avoid a large catch up at year end.

FY2008 SFAS 87 Expense

The SFAS 87 results shown in Table 1 are based on the assumptions used at FY2007 disclosure, including a discount rate of 6.25% and a long-term rate of return on assets of 8.25%. We used census data as of January 1, 2008 to determine the FY2008 results. Table 3 includes a more complete description of other assumptions and methods.

The total SFAS 87 expense for FY2008 of $529,402 is below the initial budget of $581,000 provided in our August 1, 2007 letter by roughly $52,000. Following are the primary reasons for the difference:

- The service cost component of expense was lower than the service cost from prior estimates due to the higher discount rate used for FY2007 disclosure (estimates were based on a 5.75% discount rate; disclosure results were based on a 6.25% rate), and the spin-off/termination of the defined benefit pension benefits for the USW 5-00843 union members.

W

- The unrecognized loss as of January 1, 2008 was lower than the amount used for the initial estimate of the FY2008 expense due to the higher discount rate used for FY 2007 disclosure and recognition of the spin-off/plan termination of the defined benefit pension benefits for the USW 5-00843 union members.

- Decrease in the prior service cost amortization payment included in the determination of the FAS 87 expense from the initial estimates caused by the immediate recognition required during FY2007 under SFAS 88 due to the spin-off/termination of the pension benefits for USW 5-00843 members.

- Offsetting the savings described in the first three bullets is an increase in the interest cost component of the expense. The interest cost increased due to the higher discount rate used in calculating the FY2008 expense, combined with the fact that a significant portion of the Retirement Plan's participants are retirees.

- The expected return on assets component of the expense is lower than the prior estimate due to the immediate recognition of the past investment gains and losses through the regular settlement accounting and the special accounting associated with the USW 5-00843 spin-off. The expected return on assets component is lowered by the past asset losses working their way through the Market-Related Asset Value (MRAV) determination. Once past investment losses are included in the MRAV, they are also included in the (gain)/loss subject to recognition.

We have assumed that there will be no cash contributions made to the Plan during 2008.

* * * * *

The undersigned consultants of Watson Wyatt Worldwide with actuarial credentials collectively meet the Qualifications Standards of the American Academy of Actuaries to render the actuarial opinions contained herein. To the best of our knowledge, all plan participants on January 1, 2008, and all plan provisions have been reflected in the valuation. In our opinion, all calculations and procedures are in conformity with generally accepted actuarial principles and practices; and the results presented comply with the requirements of Statements of Financial Accounting Standards including modifications made by SFAS 132, as applicable.

The calculations summarized in these exhibits involve actuarial calculations that require assumptions about future events. Equitable Resources, Inc. is responsible for the selection of assumptions for SFAS 87 purposes. We believe that the assumptions used in the report are reasonable and appropriate for the purposes for which they have been used. There is no relationship between Equitable Resources, Inc. and Watson Wyatt Worldwide that impacts our objectivity.

This report should not be used for other purposes, distributed to others outside Equitable Resouces, Inc. or relied upon by any other person without prior written consent from Watson Wyatt Worldwide.

If you wish to discuss these results in more detail, please feel free to call.

Sincerely yours,

Francis X. Reagan

Francis X. Reagan, F.S.A., E.A.
Consulting Actuary

Matthew C. Kaiser

Matthew. C. Kaiser, A.S.A., E.A.
Consulting Actuary

MCK:tbs

Enclosure: Tables

cc: Mr. David J. Smith (w/enclosure)
Ms. Theresa Z. Bone (w/enclosure)
Ms. Mary Krejsa (w/enclosure)

OTS Statement No. 2-SR
Witness: Debra Backer

11/19/08
ABG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Surrebuttal Testimony

of

Debra Backer

Office of Trial Staff

Concerning:

OPERATING & MAINTENANCE EXPENSES

CASH WORKING CAPITAL

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

A. My name is Debra Backer. I am a Fixed Utility Financial Analyst in the Technical Division of the Pennsylvania Public Utility Commission's Office of Trial Staff (OTS). My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I have submitted OTS Statement No. 2 and OTS Exhibit No. 2.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL?

A. The purpose of my surrebuttal is to respond to the rebuttal of Equitable Gas witnesses Jeffery C. Mitchell and David W. Ross.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments:

	Equitable Claim	OTS Recommended Claim	OTS adjustment
Rate Case Expense	$ 508,235	$ 368,080	($ 140,155)
Pensions Expense	$ 2,457,296	$ 0	($ 2,457,296)
Advertising Expense	$ 15,121	$ 2,481	($ 12,640)
Total O&M Adjustments			($ 2,610,091)
Cash Working Capital	$11,335,335	$ 8,769,589	($ 2,565,746)

RATE CASE EXPENSE

Q. WHAT IS EQUITABLE'S CLAIM FOR RATE CASE EXPENSE?

A. Equitable's rate case expenses were updated by Equitable's witness Jeffery Mitchell in Schedule JCM-10 for a claim of $508,235 (($1,051,160/3 years) + $153,000 management audit and service life study amortized over 5 years + $13,474 HTY regulatory expense - $8,626 West Virginia matters).

Q. WHAT ADJUSTMENT DID YOU RECOMMEND FOR RATE CASE EXPENSE IN YOUR DIRECT TESTIMONY?

A. I recommended two adjustments regarding Equitable's rate case expense. First, I recommended the amount be normalized instead of amortized. Secondly, I recommended the amount be normalized over five years, rather than the three years proposed by the Company.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION IN REBUTTAL?

A. Yes. Equitable's witness Mr. Mitchell stated on p. 21 of his rebuttal that he did not agree with the normalization period of five years as proposed by OTS and OCA's witness Lafayette K. Morgan. Witness Mitchell admits on page 20 of his rebuttal that the Company has a sporadic filing history but is forecasting that Equitable will file again in three years. Although Equitable believes it may file for another rate case in three years, it is customary to use filing history, not the Company's future intentions, to determine the normalization period.

Q. WHY IS FILING HISTORY USED TO BASE NORMALIZATION PERIODS?

A. Filing history is something that can be proven, whereas intentions to file are speculative. As shown in my Direct Testimony on page 7, the Company has a sporadic filing history. The Company's filing interval between rate cases of 8.3 years does not support the three years the Company is requesting. The Company's historic tendencies are sporadic and the Company's future intentions are speculative, so in the ratepayer's best interest, I recommend a normalization period of five years. The Company claiming a shorter normalization period means burdening the ratepayers with $140,155 ($516,861 Company's request - $368,080 OTS recommendation) in higher rates that the Company's history does not support.

Q. DO YOU HAVE ANY OTHER COMMENTS ON RATE CASE EXPENSE?

A. Yes. I accept Equitable's witness Mr. Mitchell update of rate case expense to remove the West Virginia amounts of $8,626. Using the Company's updated total of $1,051,160 normalized over the OTS recommended 5 year period results in a rate case expense of $368,080, a reduction of $140,155 to the Company's claim of $508,235.

PENSION EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR PENSION EXPENSE?

A. Equitable's employee pension and benefit expense claim is $3,252,732 as presented in Equitable's Ex. III, A. 17, p. 11. The claim is split between Pensions and Benefits.

Q. WHAT ADJUSTMENT DID YOU RECOMMEND TO THIS CLAIM IN YOUR TESTIMONY?

A. I recommended the entire Pension Expense claim be removed from the rate case filing based on the Company's contribution history and its future test year intention not to contribute to the trust.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION IN REBUTTAL?

A. Yes. Equitable's witness Mr. Mitchell stated on page 17 of his rebuttal testimony that the Company did not make cash payments to the pension plan in 2007 and has not made any cash payments in 2008. However, he claims the Company expects to make cash payments in 2009.

Q. DO YOU AGREE WITH THE COMPANY USING EXPECTED EXPENSE-BASED FUNDING IN THE COST OF SERVICE?

A. No. Company witness Mitchell makes several claims with respect to the Company's expense based approach that are incorrect. First witness Mitchell claims on page 16 of his rebuttal testimony starting on line 17, "the expenses are recognized over the life of the plan based on assumptions that are subject to annual audits and independent actuarially determined calculations." This argument is a moot point because the actual funding I recommend be used for Equitable's pension expense also recognizes expenses over the life of the plan. Over the life of the plan, the total amount of money going into the pension would be the same using either methodology.

Company witness Mitchell also states on page 16, starting on line 19, "expenses are less volatile in amount than cash payments as cash payments might only be made periodically based on the ERISA minimum funding obligations." The actuary uses the same valuation for expenses and ERISA requirements which smooth out the changes in assets and obligations of the plan. As a result, volatility would be minimized.

Company witness Mitchell also states on page 16, starting on line 21, "expenses are not subjective as they are based on the actuarial calculations, whereas cash payments are subjective in nature as the Company may make more payments than the required minimum if it so chooses." ERISA is a set calculation and is the basis for the Company's cash contributions to the trust.

Q. WHY IS THE CASH-BASED FUNDING A PREFERRED RATEMAKING METHODOLOGY?

A. The Company's expected expense-based approach is based upon speculation and may result in unwarranted expenses to ratepayers. Contrarily, the cash-based approach is based on known and measurable amounts and treats ratepayers in a fair manner.

Q. IS YOUR RECOMMENDATION STILL THE SAME?

A. Yes. I recommend denying the entire Pension Expense claim of $2,457,296. The Company has not made any recent cash payments and is not going to make any cash payments in 2008. The Company admits it has not made these payments and a decision should not be based on future intentions.

<u>CASH WORKING CAPITAL (CWC)</u>

Q. WHAT WAS YOUR RECOMMENDED ALLOWANCE FOR CWC?

A. I recommended a CWC allowance of $8,670,950. This represents a $2,644,385 reduction to the Company's filed claim.

Q. WOULD YOU PLEASE EXPLAIN YOUR ADJUSTMENTS TO CWC?

A. Yes. First, I recommended reducing Equitable's revenue lag days from 49.29 to 47.29 by reducing the billing lag (included in the revenue lag) from 4.88 to 2.88 lag days.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION IN REBUTTAL?

A. Yes. Equitable's witness Mr. Ross disagrees with reducing the billing lag days (DWR-Rebuttal, p. 5). At page 7, Mr. Ross states that due to the current billing process and CIS system, the lag represents how Equitable actually bills.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 2.88 BILLING LAG DAYS?

A. My recommendation to reduce the billing lag days is based on the fact that the Company uses an extra day to read meters that I believe is unnecessary and it holds all bills to fix audit exceptions. The Company has Automated Meter Readers (AMR) that according to the Company are timely and efficient, yet the Company's lag days have increased since the last base rate case filed over eleven years ago. With the improvements in technology using AMR that Equitable implemented in 2006, the lag days should have decreased not increased, since the last case. The increase in lag days is not logical. I recommend Equitable reduce the billing lag to show a more accurate representation of how billing is more efficient now with Automated Meter Readings (AMR). The untimely billing process increases the cash working capital requirement and rates to the customers.

Q. DO YOU HAVE ANY COMMENT REGARDING THE COMPANY CLAIMS THAT THE BILLING LAG INCREASED SINCE THE LAST RATE CASE BECAUSE GATHERING METERS INCREASE THE LAG DAYS?

A. Yes. According to Company Witness Mr. Rettger, AMR are supposed to be accurate and provide timely reads in an efficient way. The AMR are not living up to their claims of being efficient and accurate because the billing lags increased since the last Equitable base rate case. Ratepayers should not be burdened by the current billing process of increased lag days and the Company should not flow costs through to the ratepayers for the increased days it takes to bills customers. An accurate and efficient system should reduce the lag to customers, not increase it.

Q. IS THERE AN IMPACT ON RATEPAYERS BY HOLDING ALL BILLS TO BE MAILED UNTIL AUDIT EXCEPTIONS ARE WORKED?

A. Yes. The Company holds all bills one extra day while audit exceptions are worked. Only approximately 1,000 audit exceptions are created monthly, which is 5.5% - 8.3% of the meters read, 94.5% - 91.7% are correct readings. By holding all bills, not just the audit exceptions readings, an extra day causes the Cash Working Capital requirement to increase $1,264,582. This can be calculated by using Equitable's filing, Exhibit VI, Item 18, p.2 and inserting 48.29 revenue lag days instead of 49.29 revenue lag days. Equitable blames the Company's CIS system for not being able to only send out the correct bills (Ross Testimony, p. 7). Due to this flaw in the CIS system, Equitable requires an additional $1,264,582 in the CWC requirement. This is unfair, unjust, and unreasonable to the 94.5% - 91.7% of the customers who had correct meter reads. The Company claims how accurate and efficient the AMR, yet the billing lags have increased since the Company started using these.

Q. WHAT WAS YOUR NEXT RECOMMENDATION TO CWC?

A. I corrected two areas of the Injuries and Damages Insurance claim.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION IN REBUTTAL?

A. Yes. Witness Ross accepted my recommendations to exclude a second insurance payment and to update the punitive claim on the Injuries and Damages Insurance worksheet (DWR-Rebuttal, p. 1).

Q. WHAT WAS YOUR NEXT RECOMMENDATION TO CWC?

A. My next recommendation to CWC was to correct the date for the entity other O&M – OSS worksheet for C. Leon Sherman & Associates with accurate dates.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION IN REBUTTAL?

A. Yes. Witness Ross agreed to update the dates and calculated a new lag of 35.49 for other O&M Expenses (DWR-Rebuttal-1, p. 1).

Q. DO YOU AGREE WITH THE COMPANY'S OTHER O&M RECALCULATED EXPENSE LAG DAYS?

A. Yes.

Q. WHAT IMPACT DOES THE CWC CHANGES AND CORRECTIONS HAVE ON THE CWC REQUIREMENT FOR EQUITABLE?

A. Equitable's filing claimed a total cash working capital requirement of $11,335,335 for the twelve months ended December 31, 2008. After inputting the corrections and changes I recommended, Equitable's total cash working capital requirement would be $8,769,589 resulting in a $2,565,746 reduction to CWC as filed by the Company.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CWC ADJUSTMENTS?

A. Yes. I reduced the billing lag days from 4.88 lag days to 2.88 lag days. The following items that I recommended and Equitable accepted through witness Ross were: 1) correcting two areas of the Injuries and Damages Insurance claim by removing a second insurance claim and updating dates in the punitive expense claim with accurate dates and 2) correcting dates in the entity other O&M – OSS worksheet for C. Leon Sherman & Associates with the accurate dates as provided by Equitable.

Q. DOES YOUR RECOMMENDED CWC ALLOWANCE OF $8,769,589 REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes and rate base must be consistently brought together in the ALJ's Recommended Decision and again in the Commission's Final Order. This process, which is known as "iteration", effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

<u>ADVERTISING EXPENSE</u>

Q. WHAT ADJUSTMENT DID YOU RECOMMEND TO ADVERTISING EXPENSE?

A. I recommended an expense reduction of $12,640 to the Company's claim. My recommendation was based on a disallowance of sponsorships and other promotions the Company classified as other programs included in Account #913.0 Advertising expenses (OTS Ex. 2, Sch. 2).

Q. WHAT WAS THE COMPANY'S RESPONSE?

A. The Company agreed to the reduction in witness Mitchell's rebuttal p. 28.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL?

A. Yes.

OTS Statement No. 3
Witness: Amanda Gordon

11/19/08 RJS
ABG, PA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Direct Testimony

of

Amanda Gordon

Office of Trial Staff

Concerning:

Universal Service and Energy Conservation

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amanda Gordon. My business address is P.O. Box 3265, Harrisburg, Pa. 17105-3265.

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

A. I am employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff (OTS) as an expert witness.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN UTILITY REGULATION.

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

Q. PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS.

A. OTS was established by the legislature and is responsible for protecting the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address Equitable Gas Company's (Equitable or Company) Universal Service and Energy Conservation program. The issues I will address include, Commission CAP Policy Guidelines, Hardship Fund and its cost recovery mechanism Rider-D.

A. MAXIMUM CAP CREDIT

Q. WHAT IS MEANT BY THE TERM CAP CREDIT?

A. The term CAP credit is the difference between the actual bill amount (the customer charge plus volume of gas multiplied by the commodity rate) and the payment the CAP customer is requested to pay (percentage of gross household income). The difference between the two amounts is the CAP credit and is recovered in rates from non-CAP residential customers.

Q. WHAT IS A MAXIMUM CAP CREDIT?

A. The maximum CAP credit is the limit to the amount of CAP credit a customer can receive. After a customer reaches the maximum CAP credit, the customer must pay the actual bill amount (the customer charge plus volume of gas multiplied by the commodity rate).

Q. HAS THE COMMISSION ADDRESSED THIS ISSUE RECENTLY IN A GENERIC PROCEEDING?

A. Yes. The Commission addressed the issue of maximum CAP credits in its final Order regarding Customer Assistance Programs at Docket No. M-00051923 on December 18, 2006. The Commission adopted a maximum CAP credit of $1,000 for natural gas heat.

Q. DOES EQUITABLE HAVE A MAXIMUM CAP CREDIT?

A. No.

Q. ARE YOU IN AGREEMENT WITH THE COMPANY'S LACK OF A CAP CREDIT MAXIMUM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company follow Commission policy and impose a CAP maximum of $1,000 for natural gas heat.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. According to Equitable, the Company does not now, impose a maximum CAP credit. The maximum CAP credit should be maintained because eliminating it or failing to impose it erases the basic tenets of energy conservation and personal responsibility involved in all Universal Service and Energy Conservation programs. A CAP customer must be held responsible for gas usage that exceeds an acceptable level. It is not in the public interest to permit a CAP customer to enjoy an unlimited supply of gas at the expense of that burden falling on non-CAP customers. The remaining non-CAP residential customers will bear the burden to subsidize these customers. This burden is disportionately greater for the customers who are just above 150% of the Federal poverty line.

Q. HAVE YOU ESTIMATED THE COST OF NOT IMPOSING A MAXIMUM CAP CREDIT?

A. Yes. I estimate that the cost (excess burden) of providing natural gas to customers that exceed the maximum CAP credit is $8 million annually (OTS Exhibit No. 3, Schedule 1).

Q. DESCRIBE THE METHOD YOU USED TO QUANTIFY THE EXCESS BURDEN OF CAP CUSTOMERS WHO CONTINUED TO RECEIVE CAP BENEFITS AFTER EXCEEDING THE CAP MAXIMUM CREDIT.

A. The Company stated in response to OTS-RE-62-D, that 3,427 CAP customers exceeded the maximum CAP credit of $1,000 in 2007. However, because the Company does not impose the Commission's

Guideline on maximum CAP credits, the Company is unable to estimate the cost of CAP customers who continued to receive benefits after exceeding the maximum CAP credit. As a result, I have used the Company Attachment JMQ-2 as a template for estimating the cost of providing these customers with service. OTS Exhibit No. 3, Schedule 1 shows my calculation. I have multiplied the 3,427 participants who exceed the maximum CAP credit by the monthly charge of $11.65 times twelve months to arrive at the annual monthly service charge revenue of $479,095. I have calculated the annual Mcf volumes to be 454,626 Mcf, by multiplying the 3,427 participants by the average annual CAP customer consumption of 132.66 Mcf for 2007. I have multiplied this volume by the Delivery Charge of $2.253/Mcf, the new Rider C of $0.01/Mcf, the Natural Gas Supply of $13.97/Mcf, and the Balance Charge of $0.18/Mcf to arrive at a Gas Supply total amount of $7,584,523. The total cost of the supplying the 3,427 exceeding participants for a year is $8 million, this is the cost of not enforcing a CAP maximum credit.

Q. HOW DOES THIS BURDEN AFFECT CUSTOMERS WHO ARE CLOSE TO 150% OF THE FEDERAL POVERTY LINE (FPL)?

A. This burden of not enforcing a CAP maximum credit has a greater impact on those customers who are close to 150% of the FPL. These customers have less income to subsidize the excessive energy use of CAP customers who do not conserve their energy. As a result, these customers must spend a larger percentage of their income to subsidize CAP customers that exceed the CAP maximum credit.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission's CAP Policy guideline of a maximum CAP credit of $1,000 for natural gas heat be accepted and enforced for two reasons. First, this guideline balances the benefits received by low-income customers with the cost of that benefit borne by non-CAP residential customers. Second, by not enforcing this Commission guideline, the Company is burdening the non-CAP residential customers with an estimated $8 million annually, by not removing CAP customers who abuse this benefit. Certainly, not all CAP customers abuse this benefit. In fact, the majority conserve their energy usage within the Commission's approved limits. However, CAP customers have no incentive to keep their energy usage at an acceptable level if there are no consequences for irresponsible usage.

B. <u>HARDSHIP REPAIR FUND</u>

Q. WHAT IS THE HARDSHIP REPAIR FUND?

A. Equitable's Hardship Repair Fund provides assistance to customers below 175% of the FPL whose heating service has been interrupted because of a line leak or broken heating equipment.

Q. HOW IS THE HARDSHIP FUND FUNDED?

A. The Hardship Repair Fund is currently funded through funds remaining from the Gulf-TETCO settlement of 1989. Equitable anticipates that the fund will be exhausted before the end of 2008.

Q. HOW HAS THE COMPANY PROPOSED TO CHANGE THE FUNDING OF THE HARDSHIP FUND?

A. Equitable is proposing to waive the LIURP regulations at 52 Pa. Code Chapter 58 to use any unspent LIURP funds to operate its Hardship Repair Fund.

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

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company's proposal to waive the LIURP regulations be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company's proposal to waive LIURP regulations to fund the Hardship Repair Fund should be denied because there has not been excess LIURP funding since 2005, thus there would effectively be no funding for Hardship Repair Fund. Also, the LIURP program, in addition to providing insulation and conservation measures, provides heating equipment repair and replacement for households at or below 200% of the FPL. These are services similar the Hardship Repair Fund. Approving a wavier of LIURP regulations is unnecessary and impractical considering that LIURP has not recently had excess funds and it provides many of the same services to a larger low-income population.

C. <u>RIDER D DETERMINATION</u>

Q. WHAT IS RIDER D?

A. Rider D is a recovery mechanism for Equitable's Universal Service Costs. The proposed Rider D rate is $1.4384/Mcf (Company Attachment JMQ-2).

Q. HAS THE COMPANY CALCULATED RIDER D APPROPRIATELY?

A. No. The Company has included a Rider C rate of $0.227/Mcf and a State Adjustment Surcharge (STAS) amount of ($40,839) in its proposed calculation.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company calculate Rider D with the new Rider C rate of $0.01/Mcf and the STAS amount be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The inclusion of STAS costs in a Universal Service Recovery Mechanism is not appropriate because STAS is not a legitimate Universal Service cost. A new Rider C has been proposed by the Company to recover NRG costs and its new rate should be reflected in the Rider D determination.

Q. WHY IS STAS NOT A LEGITIMATE UNIVERSAL SERVICE COST?

A. According to Pa. C.S.§ 2202 Universal Service and Energy Conservation, the policies, practices and services that help residential low-income retail gas customers to maintain natural gas supply and distribution are considered legitimate Universal Service and Energy Conservation costs.

STAS is none of those items and should not be included in the determination of Rider D. STAS permits utilities under its jurisdiction to recover portions of the Capital Stock Tax, Corporate Net Income Tax and Gross Receipts Tax and the Public Utility Realty Tax through a surcharge on rates charged to customers without having to file a base rate case every time a tax rate changes. A company's State Tax Adjustment Surcharge is to be set to zero in a base rate case, to reflect that current tax rates are included in proposed rates.

Q. WHAT IS THE RESULT OF YOUR ADJUSTMENT?

A. The result of my adjustment is shown on OTS Exhibit No. 3, Schedule 2, showing an adjusted Rider D rate of 1.3978/Mcf

D. <u>RIDER D RECOVERY</u>

Q. CURRENTLY, HOW IS RIDER D RECOVERED?

A. The current Rider D is non-reconcilable and is adjusted quarterly on a prospective basis.

Q. HOW IS THE COMPANY PROPOSING TO CHANGE RIDER D IN THIS PROCEEDING?

A. The Company proposes to make quarterly adjustments to Rider-D to track changes in tariff rates and participation rates. Additionally, Equitable is requesting to make Rider D reconcilable on an annual basis.

Q. ARE YOU IN AGREEMENT WITH THE COMPANY'S RECONCILIATION OF RIDER-D?

A. No.

Q. WHAT IS THE COMMISSION'S POSITION ON RECONCILIATION?

A. In the Commission's final order regarding Customer Assistance Programs at Docket No. M-00051923, the Commission provides the following guidance on how to appropriately fund CAP's:

> ...(1) reconciled periodically to recover the actual level of costs, or (2) adjusted prospectively on a quarterly basis to track changes in the costs.... Accordingly, the Commission must allow recovery through a surcharge that is either reconciled or adjusted frequently to track changes in the level of CAP costs consistent with the direction given by the Competition Acts.

Q. WHAT IS YOUR RECOMMENDATION FOR RIDER D?

A. OTS recommends the Company's request for annual reconciliation be denied and that instead the surcharge be adjusted prospectively on a quarterly basis to track changes in the costs.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. An annual reconciliation provides no incentive for the Company to control costs or create more cost effective measures. The Company has no incentive to control CAP costs if it is guaranteed dollar for dollar recovery. The Company has also asked to use a form of both of the recommended recovery mechanisms given by the Commission, instead of selecting one.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Company adjust Rider D quarterly on a prospective basis.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A
PROFESSIONAL AND EDUCATIONAL EXPERIENCE
AMANDA L. GORDON

Professional Experience

November 2005 – Present: Office of Trial Staff, Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania

Fixed Utility Financial Analyst (November 2006-Present) – Responsible for the analysis and review of revenues and expense claims in formal and informal base rate filings and 1307(f) proceedings.

Fixed Utility Financial Analyst Trainee (November 2005-October 2006) – Assisting in the analysis and review of revenues and expense claims in formal and informal base rate filings and 1307(f) proceedings.

August 2003 - October 2005: Commerce Bank, Harrisburg, Pennsylvania

Commercial Credit Analyst (September 2004 – October 2005) - Evaluate and assess company and individual financial statements, revenues, expenses, cash flow, and credit worthiness. Collect and compile financial data from clients. Aid in determining the most appropriate lending instrument for a variety of client types. Analyze the current and ongoing risks of different loan instruments. Research clients' previous loan performance.

Customer Service Representative (August 2003 – September 2004) - Open and close bank accounts and aid in personal loans applications and approvals. Perform account maintenance and compile customer information. Troubleshoot customer difficulties and advise customers.

Education

Robert E. Cook Honors College at Indiana University of Pennsylvania, Indiana, Pennsylvania
Bachelor of Science; Major in International Business, 2003

Society of Utility and Regulatory Financial Analysts, Certified Rate of Return Analyst
Attended IPU NARUC Utility Rate School
Attended IPU Annual Regulatory Policy Conference

Testimony submitted

National Fuel Gas Distribution Corporation, 1307(f) – Docket R-00072043
Columbia Gas of Pennsylvania, Inc., 1307(f) – Docket R-00072175
Equitable Gas Company – Docket P-00062240; M-00051923
Aqua Pennsylvania, Inc. – Docket R-00072711
National Fuel Gas Distribution Corporation, 1307(f) – Docket R-2008-2012502
Columbia Gas of Pennsylvania, Inc., 1307(f) – Docket R-2008-2028039
Columbia Gas of Pennsylvania, Inc. – Docket R-2008-2011621
PECO Energy Company – Docket M-00061945
PECO Energy Company – Docket R-2008-2028394
PPL Electric Utilities Corporation – Docket R-00072155
Valley Energy, Inc. – Docket R-00072349

OTS Statement No. 3-S
Witness: Amanda Gordon

11/19/08
HBG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Supplemental Direct Testimony

of

Amanda Gordon

Office of Trial Staff

Concerning:

Universal Service and Energy Conservation

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amanda Gordon. My business address is P.O. Box 3265, Harrisburg, Pa. 17105-3265.

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

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff (OTS) as an expert witness.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY IN THIS INSTANT PROCEEDING?

A. Yes. I submitted OTS Statement No. 3 and OTS Exhibit No. 3.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Upon my further review of my direct testimony and exhibits, I would like to fully explain and update an adjustment shown in the exhibits that accompany my direct testimony that is not explained in my direct testimony regarding the amount of Energy Assistance that should be included in the Equitable's Universal Service Rider –D calculation.

Q. DOES YOUR SUPPLEMENT TO YOUR DIRECT TESTIMONY INCLUDE EXHIBITS?

A. Yes. I have added OTS Exhibit No. 3-S, Schedules 1, 2, 3 and 4 to illustrate my adjustment.

<u>**ENERGY ASSISTANCE**</u>

Q. WHAT IS THE COMPANY'S CLAIM FOR CRISIS ENERGY ASSISTANCE?

A. The Company has claimed a total of $1,065,876.18 of annual CRISIS Energy assistance revenue received by CAP customers in response to OTS-RE-53-D (OTS Exhibit No. 3-S, Schedule 1).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM REGARDING CRISIS ENERGY ASSISTANCE?

A. The Company explained in response to OTS-RE-108-D that this number is based on an average grant amount of $301.75 from October 2006 to September 2007 multiplied by the number of CAP participants expected to receive CRISIS Energy assistance in the future (OTS Exhibit No. 3-S, Schedule 2).

Q. IS THIS AMOUNT OF CRISIS ENERGY ASSISTANCE APPROPRIATE?

A. No. It is not in line with a pattern of assistance shown in the Company's corrected response to OTS-RE-60-D (OTS Exhibit No. 3-S, Schedule 3).

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company's Crisis Energy Assistance amount be $1,337,692: $1,159,447 for current CAP customers and $178,245 for future CAP participants.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I have recommended the CRISIS Energy Assistance amount be increased because it better represents the Company's CAP participant's energy assistance pattern. I have averaged the Company's CAP recipient CRISIS Energy assistance for the last three years from OTS-RE-60-D (OTS Exhibit No. 3-S, Schedule 4) and employed the average of $377.67 to create my adjustment (OTS Exhibit No. 3-S, Schedule 5). I have multiplied the $377.67 of CRISIS Assistance times the 3070 current CAP customers estimated to receive CRISIS Assistance and the 19% of 2484 estimated new CAP customers. The amount of CRISIS Assistance received by current CAP customers is $1,159,447 (3070 * $377.67). The amount of CRISIS Assistance received by future CAP customers is $178,245 (2,484 * 19% * $377,67). The per participant amount that the Company is currently employing of $301.75 is lower than each of the last three years' average CRISIS Energy Assistance amounts.

Q. WHAT IS THE RESULT OF YOUR RECOMMENDATION?

A. The result of my recommendation is that the Company's Universal Service Rider D calculation on Attachment JMQ-2 in reduced. The result of this adjustment and my adjustments to the Company's Rider- C and STATS claims is a decrease of $781,169 to the Rider D calculation. This results in a Rider D rate of 1.3987/mcf.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

OTS Exhibit No. 3-S
Witness: Amanda Gordon

11/19/08
HBG, PA PJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Supplemental Direct Testimony

of

Amanda Gordon

Office of Trial Staff

Concerning:

Universal Service and Energy Conservation

Docket No. R-2008-2029325
Item: OTS-RE-53-D
Respondent: John M. Quinn
Position: Vice President, LDC Rates and Gas Supply
Sheet: 1 of 2

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-53-D

Reference Attachment JMQ-2. How was the CAP payments amount of $14,854,021 determined? Provide supporting calculations and documents.

Response:

Refer to OTS-RE-53-D, Sheet 2 of 2. The total CAP payments are the sum of: Current CAP customers, $12,909,938 and Projected CAP Additions $1,944,083.

Docket No. R-2008-2029325
Item: OTS-RE-53-D
Respondent: John M. Quinn
Position: Vice President, LDC Rates and Gas Supply
Sheet: 2 of 2

Equitable Gas Company
CAP Customer Payments

Line No.			Total	Continuing	Delinquent	Total		
1	Current CAP Customers			66% of customers	34% of customers		Per 2007 USRR (avg mthly)	
2	*CAP enrollment as of 12/07*		*16,492*	*10,885*	*5,607*		Per 2007 USRR	
3	Average CAP monthly payments			$ 76.00	$ 76.00		Per 2007 USRR	
4	Expected Monthly Payment			$ 76.00	$ 76.00		Per 2007 USRR	
5	Subtotal			$ 9,926,866	$ 2,983,073	$ 12,909,938	Line 2 x line 4	Percent of CAP custo
6	LIHEAP Energy Assistance	$ 241.17	10,513			2,535,420		63.7%
7	CRISIS Energy Assistance	$ 301.75	3,070			926,375		
8	CAP customer payment revenue					$ 16,371,733	Sum of Lines 5, 6	
9	Projected CAP Customer Additions							$ 1,464,677
10	Projected additions		2,484	1,639	844		Per forecast worksheet	
11	Average CAP monthly payments		$ 76.00	$ 1,494,868	$ 449,215			
12	Subtotal					$ 1,944,083.80	Total CAP additions pymts	
13	Energy Assistance	$ 241.17		64%		$ 381,804.27	Estimate percent eligible based on 2007 USRF	
14	CRISIS Energy Assistance	$ 301.75		19%		$ 139,501.18		
15	CAP customer payment revenue					$ 2,465,389		
16	Energy Assistance							
17	Current level of energy assistance received			$ 2,535,414			Per USRR - 2007	
18	CAP eligible customers receiving LIHEAP			10,513			Per USRR - 2007	
19	Average energy assistance per customer					$ 241.17	Per 2007 LIHEAP query from G. Saksa	

Docket No. R-2008-2029325
Item: OTS-RE-108-D
Respondent: John M. Quinn
Position: Vice President, LDC Rates and Gas Supply

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-108-D

Reference Company response to OTS-RE-53.

A. *What is the USRR that is referenced on the Attachment of this response?*

B. Provide a copy of this referenced USRR.

C. How was the average CAP *monthly payment of $76 determined?* Provide supporting documents and calculations.

D. Why has the Company included 5,607 delinquent CAP customers in its total enrollment?

E. Describe any actions taken by the Company to decrease delinquency?

F. Provide the number of CAP customers for each month from April 2004 to date. Breakdown CAP enrollment between "Continuing" and "Delinquent" CAP customers.

G. How many months on average are CAP customers delinquent before they are removed from the program?

H. *Provide a detailed description* of the Company's collection procedures from the moment a CAP customer becomes delinquent to termination; by action and by timeframe.

I. Provide the supporting calculations that determined the 66%-34% split between Continuing and Delinquent CAP customers.

J. What is the *significance of the 66%-34% allocation if* the average CAP payment is identical?

K. How did the Company determine a LIHEAP Energy Assistance amount of $2,535,420?

L. How did the Company determine an average LIHEAP Energy Assistance of $241.17?

M. How did the Company determine a CRISIS Energy Assistance amount of $926,375?

N. How did the Company determine an average CRISIS Energy Assistance of $301.75?

Docket No. R-2008-2029325
Item: OTS-RE-108-D
Respondent: John M. Quinn
Position: Vice President, LDC Rates and Gas Supply

Response:

A. The PA PUC's Universal Service Reporting Requirements.

B. Please refer to OTS-RE-108-D, Attachment 1, Pages 1 – 4.

C. Please refer to OTS-RE-108-D, Attachment 2.

D. Attachment JMQ-2 is Equitable's estimate and supporting documentation for the derivation of Rider D. As such, recent experience related to CAP bill payments demonstrates that 66% of CAP participants remain current in the program while 34% fail to make scheduled payments. Reflecting this experience in Equitable's Rider D calculation, 66% of the total 16,492 CAP customers pay the average monthly CAP payment of $76 for twelve months of the year and 34% of the 16,492 customers become delinquent and are assumed to only pay the average CAP payment seven months of the year.

E. Please refer to Exhibit III Volume 1 of 1, Item 53.53 III-E-7.

F. Please refer to OTS-RE-108-D, Attachment 3.

G. CAP customers are removed from the program only after termination. Please refer to Exhibit III Volume 1 of 1, Item 53.53 III-E-7.

H. Please refer to Exhibit III Volume 1 of 1, Item 53.53 III-E-7.

I. Please refer to OTS-RE-108-D, Attachment 2.

J. Please refer to Equitable's response to "D" above.

K. $2,535,420 is the actual LIHEAP grants Equitable customers received for the period October – September 2007.

L. The Company determined an average LIHEAP Energy Assistance of $241.17 by dividing the actual LIHEAP amounts received by the number of customer grants for the period October 2006 through September 2007. Please refer to OTS-RE-108-D, Attachment 2.

M. $926,375 is the actual CRISIS Energy Assistance grants Equitable customers received for the period October – September 2007.

N. The Company determined an average CRISIS Energy Assistance of $301.75 by dividing the actual CRISIS amounts received by the number of grants for the period October 2006 through September 2007. Please refer to OTS-RE-108-D, Attachment 2.

Universal Service Reporting - Equitable

Year 2007

Sections

Collection

LIURP

CAP

CARES

Hardship Funds

Report Year: 2007 **CAP** Description	Bottom Value
23. Program Costs - Administration ($)	$818,940.00
24. Program Costs - CAP Credits ($)	$9,834,571.00
25. Program Costs - Preprogram Arrearage Forgiveness ($)	$842,926.00
Program Costs - CAP Accounts in Arrears - ($)	
26.A. Program Costs - CAP Accounts in Arrears - not on a Payment Agreement ($)	
26.B. Program Costs - CAP Accounts in Arrears - on a Payment Agreement ($)	
Program Costs - CAP Accounts in Arrears - (#)	
27.A. Program Costs - CAP Accounts in Arrears - not on a Payment Agreement (#)	
27.B. Program Costs - CAP Accounts in Arrears - on a Payment Agreement (#)	
28. Number of Household Members Under Age 18	0.96
29. Number of Household Members Over Age 62	0.25
30. Household Size	2.38
31. Income ($)	$10,402.00
32. Source of Income	
Employment	5,208.00
Public Assistance	1,754.00
Pension/Retirement	3,730.00
Unemployment Compensation	505.00
Disability	2,515.00
Other (includes Missing Data)	2,780.00
Participation Levels By Month **33. Income at or below 50% of Poverty (#)**	
January	3,889.00
February	3,973.00
March	4,130.00
April	4,157.00
May	4,160.00
June	4,106.00
July	4,022.00
August	3,971.00
September	3,868.00
October	3,979.00
November	4,158.00

Contact BCS

Sign Off

December	4,304.00
34. Income between 51% and 100% of Poverty (#)	
January	7,776.00
February	7,964.00
March	8,392.00
April	8,509.00
May	8,462.00
June	8,317.00
July	8,177.00
August	8,117.00
September	8,074.00
October	8,130.00
November	8,454.00
December	8,782.00
35. Income between 101% and 150% of Poverty (#)	
January	2,718.00
February	2,881.00
March	3,053.00
April	3,091.00
May	3,108.00
June	3,059.00
July	3,081.00
August	3,134.00
September	3,102.00
October	3,155.00
November	3,287.00
December	3,406.00
36. Participation Levels : Default Exits - Income at or below 50% of Poverty (#)	1,073.00
37. Participation Levels : Default Exits - Income between 51% and 100% of Poverty (#)	1,829.00
38. Participation Levels : Default Exits - Income between 101% and 150% of Poverty (#)	1,096.00
39. Participation Levels : Exits other than Defaults (#)	5,057.00
40. Energy Assistance Benefits ($)	$3,464,477.00
41. Energy Assistance Benefits (#)	11,078.00
42. Number of Full CAP Payments by Month	
January	9,076.00
February	10,150.00

March	10,587.00
April	10,789.00
May	10,856.00
June	10,317.00
July	10,258.00
August	10,036.00
September	9,907.00
October	9,877.00
November	10,500.00
December	10,105.00
43. Total Annual CAP Billed Amount - (used to calculate Average CAP Bills) ($)	$14,003,193.00

44. Total Number of CAP Bills Rendered by Month (#)

January	14,383.00
February	14,798.00
March	15,576.00
April	15,757.00
May	15,720.00
June	15,482.00
July	15,280.00
August	15,222.00
September	15,044.00
October	15,264.00
November	15,899.00
December	16,492.00
45. Total Cash Payments by CAP Customers ($)	$13,181,332.00
46. Number of Full, On-Time Payments (#)	115,854.00

46.A. Source of Intake

Distribution Company	8,883.00
Community-Based Organization	95.00
Other	0.00

46.B. Participants in Multiple Programs

CAP and LIURP	123.00
CAP and CARES	94.00
CAP and Hardship Fund	1,237.00
CAP, LIURP and CARES	1.00
CAP, LIURP and Hardship Fund	4.00
CAP, CARES and Hardship Fund	35.00

LIURP, CAP, CARES and Hardship Fund 2.00

Top

SAVE

Equitable Gas
Docket # R-2008-2029325
Item: OTS-RE-108-D
Attachment 2

Letter C: average CAP payment
Per the USRR report

No. 43	Total Annual CAP billed amount:	$	14,003,193
	divided by:		
No. 44	Number of CAP bills rendered:		184,916
	Avg. CAP monthly payment	$	76

Letter I: Continuing payments
Per the USRR report

No. 42	Number of full CAP payments		122,458
	divided by:		
No. 44	Number of CAP bills rendered:		184,916
	Percent of continuing payments		66%

Letter L: average LIHEAP payment

No. 43	Total LIHEAP amount received:	$	2,535,414
	divided by:		
No. 44	Number of LIHEAP grants:		10,513
	average LIHEAP payment	$	241.17

Letter N: average CRISIS payment

No. 43	Total CRISIS amount received:	$	926,375
	divided by:		
No. 44	Number of CRISIS grants:		3,070
	average CRISIS payment	$	301.75

Equitable Gas
Docket # R-2008-2029325
Item: OTS-RE-108-D
Attachment 3

2004	Total	Current	Delinquent
January	10,035	5,603	4,432
February	10,218	5,807	4,411
March	10,401	6,011	4,390
April	10,603	5,859	4,744
May	10,933	5,710	5,223
June	11,155	6,209	4,946
July	11,032	6,535	4,497
August	10,887	6,674	4,213
September	10,997	6,741	4,256
October	11,136	7,006	4,130
November	11,077	7,274	3,803
December	11,496	6,803	4,693
2005			
January	11,808	6,770	5,038
February	12,080	7,591	4,489
March	12,346	8,053	4,293
April	12,096	8,265	3,831
May	12,033	8,351	3,682
June	11,796	8,110	3,686
July	11,471	8,175	3,296
August	11,242	7,970	3,272
September	11,375	7,862	3,513
October	11,574	8,241	3,333
November	12,008	8,891	3,117
December	12,975	8,865	4,110
2006			
January	13,369	8,906	4,463
February	13,764	10,003	3,761
March	14,053	9,876	4,177
April	13,976	10,300	3,676
May	14,008	10,209	3,799
June	13,862	9,919	3,943
July	13,744	9,798	3,946
August	13,627	9,714	3,913
September	13,531	9,521	4,010
October	13,706	9,439	4,267
November	13,993	9,821	4,172
December	14,055	8,921	5,134

2007	Total	Current	Delinquent
January	14,383	9,076	5,307
February	14,798	10,150	4,648
March	15,575	10,587	4,988
April	15,757	10,789	4,968
May	15,720	10,856	4,864
June	15,482	10,317	5,165
July	15,280	10,258	5,022
August	15,222	10,036	5,186
September	15,044	9,907	5,137
October	15,264	9,877	5,387
November	15,899	10,500	5,399
December	16,492	10,105	6,387
2008			
January	17,194	10,489	6,705
February	17,966	12,040	5,926
March	18,516	11,942	6,574
April	18,673	13,082	5,591
May	18,783	12,743	6,040
June	18,729	12,454	6,275

OTS Exhibit No.3-S
Schedule 3

Docket No. R-2008-2029325
Item: OTS-RE-60-D - Revised
Respondent: Sandra L. Gagorik
Position: Manager, Universal Service & Community Outreach

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-60-D - Revised

Provide the following information for the three most recent heating seasons:

A. The number of customers receiving LIHEAP assistance.

B. The total amount of LIHEAP assistance received.

C. The number of CAP customers receiving crisis grants.

D. The total amount of CAP customer crises grants received.

Response:

A.	2007-08	16,997
	2006-07	17,421
	2005-06	19,298
B.	2007-08	$3,839,397
	2006-07	$4,034,034
	2005-06	$4,573,913
C.	2007-08	2,657
	2006-07	2,982
	2005-06	3,395
D.	2007-08	$1,083,863
	2006-07	$ 926,375
	2005-06	$1,406,983

OTS Exhibit No. 3-S
Schedule 4

CRISIS Energy Assistance received by CAP customers

Heating Season	CAP recipients	Total Amount of CRISIS awarded to CAP customers	Average award per CAP customer
2007-2008	2,657	$ 1,083,863	$ 407.93
2006-2007	2,982	$ 926,375	$ 310.66
2005-2006	3,395	$ 1,406,983	$ 414.43
			$ 377.67

OTS Exhibit No. 3-S
Schedule 5

OTS Adjusted Rider D Determination

Line no.	Description	No. of Meters	Annualized & Normalized Volumes (Mcf)	Present Rates	Present Revenue
1	CAP based on 18,976 Particpants				
2	Monthly Service Charge	227,712		$ 11.6500	$ 2,652,845
3	Commodity Charge				
4	Delievery Charge		2,528,051	$ 2.5230	$ 6,378,273
5	Rider C - Transition Cost		2,528,051	$ 0.0100	$ 25,281
6	Subtotal			$ 2.5330	$ 6,403,553
7	Rider - D - Universal Service				
8	Subtotal Non-gas				$ 9,056,398
9	Natural Gas Supply		2,528,051	$ 13.9700	$ 35,316,872
10	Balancing Charge		2,528,051	$ 0.1800	$ 455,049
11	Subtotal Gas Supply				$ 35,771,922
12	STAS				$ -
13	CAP credits				$ 35,771,922
14					
15	CAP Payments				$ 14,854,021
16	Energy Assistance				$ 4,256,514
17	Total Customer Payments				$ 19,110,535
18					
19	CAP Shortfall				$ 25,717,785
20					
21	CAP Arrearage Forgiveness				$ 780,397
22					
23	LIURP				$ 698,139
24					
25	CAP Adminstrative costs				$ 299,194
26					
27	*Total CAP/ LIURP Cost to be Recovered*				$ 27,495,515
28					
29	Normalized FTY funding at current surcharge				
30	Normalized FTY non-CAP residential throughput		19,658,593		
31	*Current Rider D Rate*			$ 0.5800	$ 11,401,984
32	Total Current Funding				
33					
34	Line 27-Line 32				$ 16,093,531
35					
36	Proposed Rider D Rate				$ 1.3987

OTS Statement No. 3-SR
Witness: Amanda Gordon

11/19/08
HBG, PA
AS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Surrebuttal Testimony

of

Amanda Gordon

Office of Trial Staff

Concerning:

Universal Service and Energy Conservation

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

A. My name is Amanda Gordon. I am employed by the Public Utility Commission in the Office of Trial Staff as a Fixed Utility Financial Analyst. My business address is Commonwealth Keystone Building, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. ARE YOU THE SAME AMANDA GORDON WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN OTS STATEMENT NO. 3 AND OTS EXHIBIT NO. 3?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my surrebuttal testimony is to address the rebuttal comments made by Equitable Energy Company (Equitable or the Company) witnesses Mr. Narkevic, Ms. Gagorik, and Mr. Quinn regarding the OTS's adjustments to Equitable's Universal Service and Energy Conservation program and its recovery.

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF MR. NARKEVIC?

A. Yes.

Q. WHAT ISSUES DOES MR. NARKEVIC ADDRESS REGARDING YOUR DIRECT TESTIMONY?

A. Mr. Narkevic argues for the inclusion of State Tax Adjustment Surcharge (STAS) in the calculation of the Universal Service Rider-D and states that my calculation of the Rider-D includes both present and proposed rate components. The Company has proposed a Rider-D rate of $1.4384/ Mcf.

Q. DO YOU AGREE THAT STAS SHOULD BE INCLUDED IN THE CALCULATION OF THE PROPOSED UNIVERSAL SERVICE RIDER-D?

A. I agree that STAS, as a per Mcf rate, not as an expense amount, should be included in the proposed Universal Service Rider-D.

Q. WHAT RATE SHOULD STAS BE SET AT IN THE PROPOSED UNIVERSAL SERVICE RIDER-D CALCULATION?

A. Since the proposed Universal Service Rider-D would be implemented at the conclusion of this base rate case, STAS would be set at $0.00/Mcf.

Q. WHY SHOULD THE STAS RATE BE SET AT $0.00/MCF AT THE CONCLUSION OF A BASE RATE CASE?

A. The STAS rate should be set at $0.00/Mcf at the conclusion on a base rate case because, as Mr. Narkevic points out, the purpose of STAS is to collect the difference in state taxes from the amount included in the Company's most recent base rate case and the actual amount that will be collected from the Company (Company Statement No. 3-R, page 12 and 13). At the conclusion of a base rate case, the amount included in base rates and the actual amounts to be collected should be the equal, thus setting STAS to $0.00/Mcf. The proper regulatory treatment of STAS is to reset it to zero at the conclusion of a rate case.

Q. MR. NARKEVIC ALSO STATES THAT IN YOUR RIDER –D CALCULATION AT OTS EXHIBIT NO. 3, SCHEDULE NO. 2, THERE ARE CURRENT AND PROPOSED RATE COMPONENTS. PLEASE RESPOND.

A. Mr. Narkevic is correct that I did not include the Company's most recent Natural Gas Supply component in my calculation of Rider-D, while including a proposed Rider-C and STAS amount. My intention in recalculating the Rider-D is to present the Rider-D at its closet future rate. I have included accompanying this testimony an exhibit (OTS Exhibit no. 3-SR, Sch. 1) that presents the Rider-D calculation with all of the current rate components that I am aware of.

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF MS. GAGORIK?

A. Yes.

Q. WHAT ISSUES DOES WITNESS GAGORIK ADDRESS REGARDING YOUR TESTIMONY?

A. Witness Gagorik continues to argue that the Company's Hardship Repair Fund should be allowed to be funded through a waiver of the Commission's LIURP regulations and that the Company should not enforce the Commission's CAP guidelines concerning maximum CAP credits.

Q. WHAT IS YOUR POSITION ON THE COMPANY'S PROPOSED WAIVER OF LIURP FUNDING?

A. I continue to oppose the company's requested waiver of the LIURP regulations for the reasons stated in my direct testimony (OTS Statement No. 3, page 9). The Company has not had excess LIURP funding since 2005 and waiving these regulations creates the possibility of diverting LIURP funds, intended to help those most in need (high usage, arrearages and low income status) to customers who are not eligible for other assistance programs such as LIURP, but meet the less targeted requirements of the Hardship Repair Fund. LIURP provides the services that mirror those provided in the Hardship Repair Fund, but targets its funds to those individuals with the greatest need.

Q. HOW DO YOU RESPOND TO WITNESS GAGORIK'S ARGUMENT THAT, GIVEN THE COMPANY'S HISTORICAL SPENDING AND THE COMPANY'S NEW LIURP REQUEST OF $698,139, THERE IS THE POSSIBILITY OF EXCESS LIURP FUNDING?

A. Witness Gagorik's argument does not reflect the Company's most recent years of LIURP spending. Although Equitable has had a carry-over balance in 14 of the last 16 years, the two years in which it has not had a carry-over, 2006 and 2007. In 2007, the Company spent $644,006 in LIURP funding and in 2006 the Company spent $704,128, exceeding the Company's current request. Furthermore, even Ms. Gagorik's language of "possibility" indicates that the Company is not sure that there will be excess funds. While the Hardship Repair Fund is an important program, rerouting LIURP funds is not an appropriate way to support it. To qualify for LIURP, a customer must be at or below 150% of the Federal Poverty Line (FPL), have a residential heating account, the customer must reside at the service address, the account must be a single dwelling unit, there may only be one account in the customer's name, the customer must be a homeowner or renter and priority is given customers with high usage and/or high arrearages. To qualify for the Hardship Repair Fund a customer must be at or below 150% of the FPL, the customer must not be eligible for other repair assistance through other programs (including LIURP), the customer must be responsible for the gas lines and heating equipment (generally a homeowner), and the gas service is for the customer's residence only. The Hardship Repair Fund is not even a program included in the Company's 2007-2009 Universal Service and Energy Conservation Plan.

Q. MS. GAGORIK STATES THAT THE ONLY WAY A NON-CAP CUSTOMER CAN QUALIFY FOR LIURP IS IF HIS ANNUAL NORMALIZED USAGE EXCEEDS 200 MCF AND HIS BALANCE EXCEEDS $750. IS THIS TRUE?

A. No. A non-CAP customer does not need to meet those requirements to be eligible for LIURP; these metrics are used in determining priority of LIURP services not eligibility.

Q. WHAT IS YOUR POSITION ON THE COMPANY'S LACK OF MAXIMUM CAP CREDITS?

A. I continue to recommend as I did in my direct testimony (OTS Statement No. 3, page 4) that Equitable follow Commission policy and impose a CAP maximum credit of $1,000 for natural gas heat. To not impose a maximum CAP credit eliminates the basic tenets of energy conservation and personal responsibility involved in all Universal Service and Energy Conservation programs. A CAP customer must be held responsible for gas usage that exceeds an acceptable level. It is not in the public interest to permit a CAP customer to enjoy an unlimited supply of gas at the expense of that burden falling on non-CAP customers. The remaining non-CAP residential customers will bear the burden to subsidize these customers. This burden is disportionately greater for the customers who are just above 150% of the poverty line.

Q. HOW HAS MS. GAGORIK REFUTED YOUR ARGUMENTS STATING THAT A LACK OF A CAP MAXIMUM DOES NOT ENCOURAGE CONSERVATION?

A. Ms. Gagorik has not refuted the crux of my argument for enforcing the Commission's CAP policy guideline.

Q. WHAT ARGUMENTS DOES MS. GAGORIK MAKE INSTEAD, FOR SUPPORTING A LACK OF MAXIMUM CAP CREDIT?

A. Ms. Gargorik argues that the Commission recognizes that some CAP customers do not have control over their consumption and that no universal service evaluation has shown that CAP customers increase usage after enrollment in CAP.

Q. THE COMMISSION HAS RECOGNIZED THAT IF A HOUSEHOLD'S CONSUMPTION IS BEYOND ITS ABILITY TO CONTROL, THE HOUSEHOLD WOULD QUALIFY FOR AN EXEMPTION FROM CAP CONTROL FEATURES; DOES THIS FACT CHANGE YOUR RECOMMENDATION?

A. No. The Commission is correct in exempting those CAP customers who have no control over their consumption. Equitable's position of not imposing a maximum

CAP credit on any customer, assumes that no CAP customer has control over their consumption, which is simply erroneous.

Q. WHY HAVE YOU NOT SUBTRACTED THE CAP CUSTOMERS WHOSE CONSUMPTION IS BEYOND THEIR CONTROL FROM YOUR ILLUSTRATION OF THE COST OF NOT IMPLEMENTING A CAP CREDIT MAXIMUM?

A. I have not excluded these customers because I do not know how many there are. The Company does not track consumption for CAP credit monitoring since it treats all of its CAP customers as if they have no control over their consumption regardless of whether they actually do or not.

Q. MS. GAGORIK REFERENCES THE COMMISSION'S FINAL INVESTIGATORY ORDER AT DOCKET M-00051923 THAT STATES "NO UNIVERSAL SERVICE EVALUATION HAS SHOWN THE CAP CUSTOMERS INCREASE USAGE AFTER ENROLLMENT"[1]. DOES THIS FACT CHANGE YOUR RECOMMENDATION?

A. No. The same paragraph that Ms. Gagorik has quoted, the Commission resolves to continue employing a consumption limit. In THAT same paragraph the Commission states "We agree that reducing consumption is critical to reducing

[1] Final Investigatory Order – Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket No. M-00051923, page 47.

CAP costs and decline to eliminate consumption limits."[2] Also, the Company's own response to OTS-RE-64-D (OTS Exhibit No. 3-SR, Schedule 2) indicates that a portion of its customers have increased consumption after enrollment. This response states that 2.1% of its CAP customers exceeded 125% of historical usage. While this is a small percentage, its does not encompass customers that increased consumption from 101% to 124%. This evidence is in contrast to Equitable's reliance on the OCA statement in the Final Investigatory Order at page 47, that no universal service evaluation has found that CAP customers increase consumption after enrollment.

Q. PLEASE SUMMARIZE YOUR CRITIQUE OF MS. GAGORIK'S REBUTTAL ARGUMENTS FOR SUPPORTING A LACK OF A CAP CREDIT MAXIMUM.

A. Ms. Gagorik has argued that a CAP maximum credit should not be imposed because many CAP customers cannot control their consumption and that no universal service evaluation has found that CAP customers increase consumption after enrollment. Neither of these arguments is credible. CAP customers who cannot control their consumption are exempted from control features at 52 Pa. Code §69.265(3)(vi). Thus arguing that a CAP maximum credit would overburden these exempted customers is ridiculous and not relevant. While no

[2] Final Investigatory Order – Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket No. M-00051923, page 47.

global universal service evaluation has shown that CAP customers increase consumption after enrollment, Equitable's own data regarding its customers show otherwise.

Q. **HAS MS. GAGORIK REFUTED THE CRUX OF YOUR ARGUMENTS REGARDING IMPOSING A MAXIMUM CAP CREDIT?**

A. No. My support for imposing a maximum CAP credit is two fold. First, this guideline balances the benefits received by low-income customers with the burden of the cost of that benefit being borne by non-CAP residential customers. Second, by not enforcing this Commission guideline, by not removing CAP customers who abuse this benefit, the Company is burdening the non-CAP residential customers with an estimated $8 million annually,. Certainly, not all CAP customers abuse this benefit. In fact, the majority of the Company's CAP customers conserve their energy usage and are within the Commission's approved limits. However, CAP customers have no incentive to keep their energy usage at an acceptable level if there are no consequences for irresponsible usage.

Q. **HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF MR. QUINN?**

A. Yes.

Q. WHAT ISSUES DOES MR. QUINN ADDRESS REGARDING YOUR DIRECT TESTIMONY?

A. Mr. Quinn addresses the imposition of a maximum CAP credit and the Company's proposed recovery method for Universal Service Rider-D.

Q. WHAT ARGUMENT DOES MR. QUINN PRESENT FOR NOT IMPOSING A MAXIMUM CAP CREDIT?

A. Mr. Quinn presents one of the same arguments that Ms. Gagorik presented: that some CAP customers have no control over their consumption and are exempted from this control feature in 52 Pa. Code §69.265(3)(vi).

Q. WHAT IS YOUR RESPONSE TO THIS ARGUMENT REGARDING THE IMPOSITION OF CAP MAXIMUM CREDIT?

A. My response to this argument is the same as my response to Ms. Gagorik's presentation of the same argument. CAP customers who cannot control their consumption are exempt from control features at 52 Pa. Code §69.265(3)(vi). The argument is not relevant since these customers would already be exempted. However, Equitable's position of not imposing a maximum CAP credit on any CAP customer, assumes that all CAP customers fall into this category, which is simply flawed.

Q. WHAT IS YOUR POSITION ON THE COMPANY'S PROPOSED RIDER-D UNIVERSAL SERVICE RECOVERY MECHANISM?

A. I continue to recommend that the Rider-D Universal Service Recovery Mechanism be adjusted prospectively on a quarterly basis in lieu of the Company's proposed recovery mechanism.

Q. WHAT HAS THE COMPANY PROPOSED AS THE RECOVERY OF ITS RIDER-D UNIVERSAL SERVICE MECHANISM?

A. The Company continues to support using both of the distinct recovery mechanisms specified by the Commission in its Final Investigatory Order at M-00051923; annual reconciliation <u>or</u> quarterly prospective adjustments.

Q. HOW HAS MR. QUINN FURTHER SUPPORTED THIS POSITION?

A. Mr. Quinn has stated that the intention of the Company was to replicate 1307(f) recovery methodology. However, if the Commission were to decide that the Rider-D must choose between the two recovery methods it specified in the Final Investigatory Order, then the Company would prefer a reconcilable Rider.

Q. WHY IS IT INAPPROPRIATE TO TRY TO REPLICATE 1307(F) RECOVERY METHODOLOGY FOR THE RECOVERY OF A UNIVERSAL SERVICE PROGRAM?

A. 1307(f) recovery methodology is inappropriate for the recovery of a universal service program because of the different size of the two types of expenses. The fact that gas expense accounts for over half of the Company's expenses is the main reason for allowing this expense to be collected in such a unique manner. Universal Service costs do not have the same magnitude, and thus should not be given the same unique manner of recovery. Also the Company has not proposed an investigation process equal to that given to the 1307(f) filings. In effect, Equitable would like the benefits of 1307(f) type recovery but, not the scrutiny or duration of a 1307(f) type investigation.

Q. PLEASE SUMMARIZE WHY YOU BELIEVE THE PROSPECTIVE QUARTERLY ADJUSTMENT METHOD IS SUPERIOR TO THE ANNUAL RECONCILIATION METHOD.

A. I believe the prospective quarterly adjustment method is superior to the annual reconciliation method because an annual reconciliation provides no incentive for the Company to control costs or create more cost effective measures. The Company has no incentive to control CAP costs if it is guaranteed dollar for dollar recovery.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OTS Exhibit No. 3-SR
Witness: Amanda Gordon

11/19/08 RJS
HBG, PA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Surrebuttal Testimony

of

Amanda Gordon

Office of Trial Staff

Concerning:

Universal Service and Energy Conservation

OTS Exhibit No. 3-SR
Schedule 1

OTS Adjusted Rider D Determination

Line no.	Description	No. of Meters	Annualized & Normalized Volumes (Mcf)	Present Rates	Present Revenue
1	CAP based on 18,976 Particpants				
2	Monthly Service Charge	227,712		$ 11.6500	$ 2,652,845
3	Commodity Charge				
4	Delievery Charge		2,528,051	$ 2.5230	$ 6,378,273
5	Rider C - Transition Cost		2,528,051	$ 0.0100	$ 25,281
6	Subtotal			$ 2.5330	$ 6,403,553
7	Rider - D - Universal Service				
8	Subtotal Non-gas				$ 9,056,398
9	Natural Gas Supply		2,528,051	$ 14.4500	$ 36,530,337
10	Balancing Charge		2,528,051	$ 0.1800	$ 455,049
11	Subtotal Gas Supply				$ 36,985,386
12	STAS				$ -
13	CAP credits				$ 36,985,386
14					
15	CAP Payments				$ 14,854,021
16	*Energy Assistance*				$ 4,256,514
17	Total Customer Payments				$ 19,110,535
18					
19	CAP Shortfall				$ 26,931,249
20					
21	CAP Arrearage Forgiveness				$ 780,397
22					
23	LIURP				$ 698,139
24					
25	CAP Adminstrative costs				$ 299,194
26					
27	Total CAP/ LIURP Cost to be Recovered				$ 28,708,979
28					
29	Normalized FTY funding at current surcharge				
30	Normalized FTY non-CAP residential throughput		19,658,593		
31	Current Rider D Rate			$ 0.5800	$ 11,401,984
32	Total Current Funding				
33					
34	Line 27-Line 32				$ 17,306,995
35					
36	Proposed Rider D Rate				$ 1.4604

Docket No. R-2008-2029325
Item: OTS-RE-64-D
Respondent: *Sandra L. Gagorik*
Position: Manager, Universal Service & Community Outreach

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-64-D

How many CAP customers over the past five twelve month periods ending December 31, 2007, 2006, 2005, 2004 and 2003 have exceeded the consumption limits of 110% of historical usage for the time period before December 18, 2006 and 125% of historical usage for the time period after December 18, 2006.

Response:

As of April 30, 2008 there were 391 accounts, or 2.1 percent of the CAP participation level, with usage exceeding 125 percent of historical usage. A further analysis shows that 69 of these accounts had annual usage of less than 90 Mcf.

Data is not available for prior periods.

OTS Statement No. 4
Witness: Michael J. Gruber

11/19/08
NBG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Direct Testimony

of

Michael J. Gruber

Office of Trial Staff

Concerning:

Cost of Service

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

A. My name is Michael J. Gruber. My business address is P. O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

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

A. I am employed by the Pennsylvania Public Utility Commission ("Commission") in the Technical Division of the Office of Trial Staff ("OTS") as a Fixed Utility Valuation Engineer.

Q. PLEASE DESCRIBE THE ROLE OF OTS IN UTILITY PROCEEDINGS.

A. OTS was established by the Pennsylvania Legislature in 1986 and is responsible for representing the public interest in specified Commission proceedings. The OTS analysis in this proceeding is based on that responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Attached to my testimony as Appendix A is a statement that describes my educational background and professional employment experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony it to present the position of the Office of Trial Staff concerning the Company's allocation of the proposed increase.

Q. WHAT FORMS THE BASIS OF THE COMPANY'S ALLOCATION OF THE PROPOSED INCREASE?

A. The Company has presented four basic cost of service studies. They are;

1) A design day allocation method with a customer component of distribution mains at present rates,

2) A peak and average allocation method without a customer component of distribution mains at present rate,

3) A design day allocation method with a customer component of distribution mains at proposed rates,

4) A peak and average allocation method without a customer component of distribution mains at proposed rates.

The Company has used these studies and its judgement to allocate the increase.

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. A cost of service study is an analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements and, to the extent a particular class is above or below the system average rate of return, show the subsidy each class receives or conversely the additional revenues that class or classes contribute to the Company's overall revenues. In addition to the actual subsidy, a relative rate of return is also provided which shows how the rate of return for each class compares to the system average rate of return.

Q. WHAT DO THESE STUDIES SHOW?

A. The results of the Company's design day study at present rates are shown on page 1 of 85, of Item 53.53 IV-B-1 (A) and the results of the peak and average study at present rates are shown on page 1 of 85 of Item 53.53 IV-B-1 (B).

The results of both cost of service studies at present rates indicate that the Residential Service class (RS) is below system average, the General Service-Small rate class (GSS) is earning a return higher than system average, the General Service-Large class (GSL) is shown to be earning an above average return, and the Appalachian Gathering System rate class (AGS) is earning a below average return which is negative.

The results of the Company's design day study at proposed rates are shown on page 1, of Item 53.53 IV-C-1 (A) and the results of the peak and average study at proposed rates are shown on page 1 of Item 53.53 IV-D-1 (B).

The results of the cost of service studies at proposed rates indicate that the Residential Service class (RS) is below system average for the design day method and above the system average for the peak and average, the General Service-Small rate class (GSS) is earning a return higher than system average under both proposed methods, the General Service-Large class (GSL) is above system average for the design day method and below the system average for the peak and average, and the Appalachian Gathering System rate class (AGS) is earning at the average return.

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE?

A. The Company used the results of the cost of service studies as guidelines for determining the level of revenue which needs to be collected from each class. Along with the cost of service studies the Company used its judgment as to the value of service to the GSL rate class.

Q. HOW DID THE COMPANY ALLOCATE THE REVENUE FROM ITS REQUESTED INCREASE BY CUSTOMER CLASS?

A. The Company's proposed revenue allocation has divided its proposed increase of $51,950,000 by rate class as follows;

RS	$40,050,000,
GSS	$1,432,000,
GSL	$2,950,000, and
AGS	$7,518,000.

Using this allocation the only rate class which would be at the proposed system rate of return of 8.89% under any of the cost of service studies would be the AGS class.

Under the Company's proposed rate allocation, the class rates of return for the design day and the peak and average cost of service studies would be:

	Design Day	Peak and Average
Total	8.89%	8.89%
RS	7.86%	9.43%
GSS	15.83%	14.92%
GSL	10.76%	5.78%
AGS	8.89%	8.89%

Q. DO YOU AGREE WITH THE COMPANY'S COST OF SERVICE ANALYSIS?

A. I will accept that the cost of service studies preformed by the Company were done and calculated properly. However, it is my opinion that the Company did not allocate this increase properly. The only rate class which the Company brought to the proposed system rate of return was the AGS rate class. The GSS rate class was given an increase even though both cost of service analyses showed that the rate class should receive a decrease rather than an increase. The RS and GSL classes receive increases somewhere between the two calculated allocations so that one is above system average rate of return and one is below depending on which cost of service study is used.

Q. HOW SHOULD THE RATE INCREASE BE ALLOCATED?

A. If the Company's entire proposed rate increase of $51,950,000 is approved the increase should be allocated as follows;

RS	$40,050,000,
GSS	$0
GSL	$4,382,000, and
AGS	$7,518,000.

Q. WHAT SHOULD BE DONE WITH ANY REDUCTION IN THE COMPANY'S PROPOSED INCREASE?

A. The first $3,011,000 in reductions should go to the RS class. Any additional relief should be used to proportionally reduce all rate classes.

Q. WHY ARE YOU RECOMMENDING THAT THE GSS CLASS GETS NO INCREASE?

A. Under all the cost of service studies preformed by the Company, the GSS class is above the system average rate of return and as such any additional increase would only increase that imbalance.

Q. WHY HAVE YOU ASSIGNED THE $1,432,000 THE COMPANY ASSIGNED TO THE GSS CLASS TO THE GSL CLASS?

A. Under the peak and average method for proposed revenue, the RS class is above system average rate of return and the GSL is not, therefore, it is my opinion that is more appropriate to raise the GSL allocation than the RS allocation.

Q. WHY SHOULD THE FIRST $3,011,000 IN REDUCTIONS GO TO LOWERING THE RS CLASS'S RATES?

A. The design day cost of service study at proposed rates uses a customer component of mains in its allocation. The peak and average cost of service study does not have a customer component of mains in its allocation. The cost of service study that I recommend be used, (the peak and average cost of service study with no customer component in mains), has a revenue allocation of $37,039,000 for the RS class. The revenue increase proposed by the Company for the RS class is $40,050,000 or $3,011,000 above the allocation calculated in the Company's peak and average proposed rate cost of service study. Therefore, the first dollar relief of $3,011,000 should go to the RS class.

Q. WHY ARE YOU RELYING ON A PEAK AND AVERAGE METHOD TO ALLOCATE THE PROPOSED REVENUE?

A. The peak and average method is a better measure of how the Company's distribution system is used. This method recognizes that while a distribution system has to be able to deliver the peak quantity needed it also uses the distribution system to deliver quantity on a daily basis as well. Further, the design day analysis done by the Company uses a customer component for mains in its allocation calculation where as the peak and average method does not.

Q. WHY DOES THE LACK OF A CUSTOMER COMPONENT IN THE ALLOCATION ON THE MAINS MAKE IT THE APPROPRIATE CHOICE IN THIS PROCEEDING?

A. The Commission has previously determined in a 1994 Opinion and Order in the Pennsylvania American Water Company case at Docket No. R-00932670, Order entered July 26, 1994, at pages 111- 115, that direct customer costs include "the *depreciation, return and income taxes associated with meter and service* investment, the operation and maintenance expense for meters and services, and the expense associated with meter reading and billing". Mains are not included in any of these categories, and therefore should not be considered or classified as a customer cost. The basis for this determination is that the quantity and investment in mains does not change significantly if one customer joins or leaves the system. Mains are built to deliver gas, and the cost of mains cannot be assigned to one specific customer. Therefore, no portion of the fixed costs or depreciation expense associated with mains should be allocated to the customer cost function.

Q. DO YOU HAVE ANYTHING FURTHER TO ADD AT THIS TIME?

A. I have nothing further to add at this time but I reserve the right to amend my testimony when I receive the answers to some outstanding interrogatories.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

MICHAEL J. GRUBER

Appendix A

Education and Professional Background

In May 1976, I received a B. S. in Civil Engineering from The Pennsylvania State University. After graduation, I was hired by the Pennsylvania Public Utility Commission and worked in the Valuation Section of the Bureau of Rates and Research in the area of electric and telephone valuation and depreciation. When the Bureau was realigned into Divisions, I specialized in telephone valuation and depreciation. Later, I was transferred to the Engineering Section of the Electric Division to work on electric company valuation and depreciation.

In October 1977, I participated in a special depreciation training program sponsored by Western Michigan University in Kalamazoo, Michigan, entitled "Fundamentals of Service Life Forecasting".

In the fall of 1977 and spring of 1979, I successfully completed accounting courses at the Harrisburg University Center, which were sponsored by Elizabethtown College.

From 1977 through early 1987, I was a Fixed Utility Valuation Engineer responsible for review and evaluation of claims for depreciation, original and trended original cost valuations, construction work in progress, plant held for future use, materials and supplies, and extraordinary property loss claim in many electric and telephone rate proceedings before this Commission.

In July 1978, I participated in a special depreciation training program sponsored by Western Michigan University at Calvin College in Grand Rapids, Michigan, entitled "Dynamics of Life Estimation".

I took part in the early stages of the "*1979 Triennial Review of The Bell Telephone Company of Pennsylvania Depreciation Review*", which was submitted to this Commission and the Federal Communications Commission (FCC) for review and comment prior to the FCC's prescribing of annual depreciation rates for the next three-year period.

Under the Commission's reorganization in 1987, I was assigned to the Office of Trial Staff, Engineering Section, and Analysis Division. In May of 1987, I was appointed as *Supervisor of the Engineering Section, Engineering and Rate Design Division of the* Office of Trial Staff, and was responsible for all rate-base, engineering and depreciation issues.

When the Office of Trial Staff reorganized in February of 1994, I was assigned the position of Assistant to the Division Chief, (of the newly formed) Telecommunications/Water Division of the Office of Trial Staff.

My duties, as Assistant to the Division Chief of the Telecommunications/Water Division of the Office of Trial Staff, involved informal training of entry level engineers and work on unusual issues which occur in the various rate proceedings before the Commission in which the Office of Trial Staff becomes involved.

I currently work as a Fixed Utility Valuation Engineer III working on a variety of utility filings.

Early in my time at the Public Utility Commission, I was a Fixed Utility Valuation Engineer in the following major rate proceedings before the Pennsylvania Public Utility Commission:

1) The Duquesne Light Company at Docket No. R.I.D 373
2) The Pennsylvania Electric Company at Docket No. R.I.D 392
3) The Metropolitan Edison Company at Docket No. R.I.D 434
4) The Bell Telephone Company of Pennsylvania at Docket Nos. R.I.D 367 and R-79060719
5) The Bethel and Mt. Aetna Telephone and Telegraph Co. at Docket No. R-77090452
6) The Mid-Penn Telephone Corporation at Docket No. R-77090462
7) The Commonwealth Telephone Company at Docket No.R-77090482

In addition, I have been a Fixed Utility Valuation Engineer in various other informal rate investigations.

I have testified in the following cases:

General Telephone Company of Pennsylvania at R-7910062
West Penn Power Company at R-80021082, F-842632, and R-850220
Pennsylvania Power & Light Company at R-8003114, R-822169, R-842651, and R-00973954
Philadelphia Electric Company at R-80061225, and R-842590
Metropolitan Edison Company at R-80051196, R-811601, and R-842770
Pennsylvania Electric Company at R-80051197, R-811602, and R-842771
Pennsylvania Power Company at R-811510, R-832409, R-850267, and R-870732
UGI Gas at R-821899, and R-870602
Duquesne Light Company at R-850021, R-860378, and R-870651
Shickshinny Water Company at R-870764
Marion Height Water Company at R-870774
National Fuel Gas Distribution Company at R-881125, R-891218, R-00942991, and R-00963779
Arrowhead Public Service Corporation at R-891557
Duquesne Light Company at P-900485
General Public Utilities at P-910502, and G-900240
LP Water & Sewer at G-910255, A-230242, A-211770
Sunshine Hills Water Company at R-912023
West Penn Power at R-00922378
MPW Utilities Inc. at A-230026
Public Service Water Company at A-210025F002
UGI Utilities Inc., (Electric) at R-00932862, and R-00973975
Pennsylvania American Water Company at R-00932670
National Utilities Inc. at R-00932670
Newtown Artesian Water Company at R-00943157
IntraLATA Interconnection Investigation at I-00940034
MFS Intelenet of PA at A-310203
Alltel at P-981423
Equitable Gas Co., 1307(f), Docket Nos. R-00016132, and R-00005067
Pike County Power & Light, Docket No. R-00011872
UGI Utilities, Inc. – Gas Division, Docket No. R-00016376
Wellsboro Electric Company, Docket No. R-00016356
T. W. Phillips Gas and Oil Company, Docket No. R-0005807
Equitable Gas Co. Restructuring Filing, Docket No. R-00099784
P.F.G. Gas, Inc. and North Penn Gas Companies, Docket No. R-0005277
T. W. Phillips Gas and Oil Company – Restructuring Filing, R-994790
T. W. Phillips Gas & Oil Company, R-00016898
The Peoples Natural Gas Company d/b/a Dominion Peoples, R-00027134;
The Peoples Natural Gas Company, P-00021952
Philadelphia Gas Works – Restructuring Filing, M-00021612

Duquesne Light Company - POLR, P-00032071
Penn Estates Utilities-Water, R-00038429
Penn Estates Utilities-Sewer, R-00038498
National Fuel Gas Distribution, R-00049108
Equitable Gas Company, R-00049154
PPL Electric Utilities Corporation, R-00049255
Valley Energy, Inc., R-00049345
UGI Utilities, Inc., R-00049422
Township of Falls - Sewer, R-00049557
National Fuel Gas Distribution Corp., R-00049656
National Fuel Gas Distribution Corp., R-00050216
Equitable Gas Company, R-00050272
UGI Utilities Inc., A-120011F2000

Some of the issues I have testified on include:

1) Depreciation and Service Life Analysis
2) Customer Contributions In Aid of Construction
3) Customer Advances for Construction
4) Construction Work in Progress
5) Material and Supplies
6) Post Test Year Plant Additions
7) Loan Financing and Repayment
8) Utility Plant Used and Useful in the Public Service
9) Cost of Gas
10) Take or Pay Obligations of Gas Utilities
11) Rules and Regulations for New Telecommunications Services
12) Contractual Obligations Between Utilities
13) Rate Structure and Tariff Issue
14) Excess Utility Plant Investment
15) Cost of Service and
16) General Prudence Issues
17) 1307(f) Gas Purchase Issues
18) Stranded Electric Costs
19) Chapter 30 Issue

OTS Statement No. 5
Witness: Jeremy B. Hubert

11/19/08
HBG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Direct Testimony

of

Jeremy B. Hubert

Office of Trial Staff

Concerning:

Forfeited Discounts
Rate Base
Depreciation Expense
Weather Normalization Adjustment
Customer Costs

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff (OTS) as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

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

Q. PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS.

A. OTS was established by the legislature and is responsible for protecting the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the forfeited discounts, rate base, depreciation expense, weather normalization adjustment, and customer costs related to Equitable Gas Company's (Equitable or Company) requested $51,949,391 base revenue increase.

Q. HOW IS YOUR TESTIMONY PRESENTED?

A. My direct testimony is presented as follows:

- A. Forfeited Discounts
- B. Rate Base:
  - 1. Gas Storage Inventory
  - 2. Customer Deposits
  - 3. Post Future Test Year Additions
- C. Weather Normalization Adjustment
- D. Customer Costs

FORFEITED DISCOUNTS

Q. WHAT ARE FORFEITED DISCOUNTS?

A. A public utility such as Equitable Gas Company assesses a separate charge for any customers who do not pay their bill on time. The term forfeited discounts revenue refers to the revenue received by the Company as a result of this charge.

Q. HOW ARE REVENUES FROM FORFEITED DISCOUNTS DETERMINED?

A. According to the Company's tariff, if a customer fails to pay the full amount of any bill, a delayed payment penalty charge of one and one-half percent (1 ½%) per month for rates RS, GSS, and GSL will accrue on the customer's bill that is unpaid on the due date. For rates CSF and CSI the finance charge will be five percent (5%) per month. According to Equitable's tariff, the final date for payment of a bill will be at most twenty (20) days after presentation (date of postmark) for residential customers and at most fifteen (15) days after presentation (date of postmark) for other than residential customers.[1, 2]

Q. HOW MUCH REVENUE FROM FORFEITED DISCOUNTS DID THE COMPANY ACTUALLY RECEIVE IN THE HISTORIC TEST YEAR ENDING DECEMBER 31, 2007 UNDER PRESENT RATES?

A. As shown in Item III-A-17 of Equitable Exhibit III, the Company received $1,557,851 in forfeited discounts revenue for the test year ending December 31, 2007. This amount represented 0.407% of Gas Sales Revenue ($1,557,851 / $382,742,414).

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[1] Supplement No. 61 to Gas-Pa. P.U.C. No. 22, Thirty-Sixth Revised Page No. 40, 41, and 42.
[2] Supplement No. 61 to Gas-Pa. P.U.C. No. 22, Original Page No. 45 and 48.

Q. WHAT LEVEL OF FORFEITED DISCOUNTS IS THE COMPANY CLAIMING AT PROPOSED RATES FOR THE FUTURE TEST YEAR ENDING DECEMBER 31, 2008?

A. Equitable is claiming that its level of forfeited discounts at proposed rates will be $1,557,851 for the future test year ending December 31, 2008 (Equitable Exhibit III, Item III-E-20, Section II: 1). This is the same amount as claimed for the historic test year, and it represents 0.337% of Gas Sales Revenue for that period ($1,557,851/$461,611,292).

Q. WHAT DO YOU RECOMMEND REGARDING THE AMOUNT OF REVENUE FROM FORFEITED DISCOUNTS THE COMPANY WILL RECEIVE UNDER PROPOSED RATES FOR THE FUTURE TEST YEAR ENDING DECEMBER 31, 2008?

A. I recommend that the revenue from forfeited discounts be increased to $1,932,397 for the future test year ending December 31, 2008. This amount is $374,546 greater than the $1,557,851 claimed by the Company (OTS Ex. No. 5, Sch. 1).

Q. HOW DID YOU DETERMINE THE $1,932,397 AMOUNT?

A. The $1,932,397 represents 0.419% of Gas Sales Revenues of $461,611,292. I determined this percentage by averaging the actual forfeited discount revenues for three historic periods; the year ended December 31, 2005, 2006, and 2007. I omitted the year ended December 31, 2003 and December 31, 2004 figures from my calculation because the percentage of forfeited discounts figure for those periods seem to be out of line with the other annual data. OTS Exhibit No. 5, Schedule 1 provides details of the calculation.

Q. WHY DO YOU RECOMMEND THAT THE REVENUE FROM FORFEITED DISCOUNTS BE 0.419% OF TOTAL GAS SALES REVENUES?

A. I believe it is reasonable to expect that forfeited discounts revenues will increase whenever a utility's base rates are increased as a result of a base rate proceeding. Since forfeited discounts are 1.5% of a customer's bill, increasing gas service revenue through a rate increase will cause revenues from forfeited discounts to increase over time. I have not seen any indication in this proceeding that the actual level of forfeited discounts as a percent of Gas Sales Revenues will decrease below 0.40% as proposed by Equitable.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE AMOUNT OF REVENUE RECEIVED FROM FORFEITED DISCOUNTS AT THE COMMISSION APPROVED REVENUE LEVEL?

A. Based on the Company's average forfeited discounts for the last three years, 2005 through 2007, I recommend that the Company include revenue from forfeited discounts equal to 0.419% of Gas Sales Revenues upon determination of the total revenue that the Company is ultimately granted the opportunity to recover through rates by the Commission.

RATE BASE

Q. WHAT IS MEASURE OF VALUE?

A. The measure of value, or rate base, is the depreciated original cost of a company's investment in utility plant determined to be used and useful in the public service at the end of the test year plus other additions and deductions that the Commission determines to be necessary plant in order to keep the utility operating and providing safe and reliable service to its customers. In this testimony, I will use the terms "measure of value" and "rate base" interchangeably.

Q. HOW IS THE DEPRECIATED ORIGINAL COST PLANT IN SERVICE AT THE END OF THE FUTURE TEST YEAR DETERMINED?

A. The depreciated original cost is determined by subtracting the book reserve, which is the accumulation of all prior annual depreciation expense, and other items such as salvage value from the original cost of the plant in service that is used and useful in the public service at the future test year end. The depreciated original cost of the plant in service is determined by taking a "snapshot" look at the depreciated original cost value of used and useful utility plant in service at a specific point it time. That point in time in this case is the end of the future test year.

Q. WHAT OTHER ADDITIONS AND/OR DEDUCTIONS TO THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT USED AND USEFUL IN THE PUBLIC SERVICE ARE ALLOWED?

A. Some of the additions to the depreciated original cost of a company's investment in utility plant used and useful in the public service include materials and supplies, gas in storage, prepayments, and cash working capital. Some of the deductions include liberalized depreciation, tax credits, and customer deposits. Some additions are applicable to a specific utility or utility type. The depreciated original cost claimed by Equitable is $608,601,655, shown on Equitable Exhibit I, Item I-A-2, Sheet 2 of 3. The claimed additions to the Company's depreciated original cost are as follows:

1. Materials and Supplies;
2. Current Gas Storage;
3. Cash Working Capital;
4. Prepayments, and

The deductions to the depreciated original cost are:

1. Deferred Income Taxes – Depreciation;
2. Deferred ITC;
3. Customer Deposits.

Q. HOW IS THE MEASURE OF VALUE USED WITHIN THE RATEMAKING FORMULA?

A. The measure of value is one part of the financial equation used by the Commission, along with allowable expenses and rate of return to determine the level of income a utility is granted an opportunity to earn and the revenue level needed to achieve that return. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Measure of Value x Rate of Return) + Allowable Expenses.

Each item in the revenue requirement equation is synchronized to the test year period. If the date of any of the items in this equation is changed, all the other necessary data that a utility must file in a rate proceeding including the test year income statement, actual and projected customer levels and usage, cost of service study to determine expense responsibility among the various customer classes, and other financial information used to determine the utility's rate of return, must also be changed.

Q. WHAT IS THE TOTAL MEASURE OF VALUE CLAIMED BY THE COMPANY FOR THE FUTURE TEST YEAR ENDING DECEMBER 31, 2008?

A. The Company's claimed measure of value for the future test year ending December 31, 2008 is $583,252,589 (Equitable Exhibit I, Item I-A-2, Sheet 2 of 3).

Q. WHAT IS A FUTURE TEST YEAR AND HOW IS IT USED BY A COMPANY IN A RATE PROCEEDING?

A. A future test year is a twelve-month period selected by a company to utilize both historic and projected annualized and normalized financial information. A future test year is used in order to allow for the time it takes to adjudicate a rate proceeding by permitting a company to select a future time period upon which to base its financial information. This is necessary so that the rates set by the Commission reflect current and synchronized financial information. By using a future test year, a company makes a projected, annualized and normalized estimate of future revenues and expenses and a corresponding measure of value at the end of the future test year.

Q. WHAT TEST YEAR HAS THE COMPANY SELECTED FOR USE IN THIS PROCEEDING?

A. The Company has selected a future test year ending December 31, 2008.

Q. DO YOU CONSIDER THE USE OF A FUTURE TEST YEAR ENDING DECEMBER 31, 2008 TO BE INAPPROPRIATE?

A. No.

GAS STORAGE INVENTORY

Q. WHY DOES THE COMPANY STORE GAS AND HOW ARE THE COSTS RECOVERED IN RATES?

A. The Company stores gas for future use. Gas is typically injected underground during the summer months for extraction and use in the peak winter months. Since the value varies from month to month, jurisdictional gas companies are permitted to include a 13 month average balance of Gas Storage Inventory in the Measure of Value as part of its inventory claim in a base rate proceeding.

Q. DOES THE $583,252,589 MEASURE OF VALUE (RATE BASE) AMOUNT INCLUDE A CLAIM FOR GAS STORAGE INVENTORY?

A. Yes. The $583,252,589 rate base claim includes $75,175,769 worth of Gas Storage Inventory (Equitable Exhibit I, Item I-A-2, Sheet 2 of 3).

Q. HOW DID EQUITABLE DEVELOP ITS CLAIM FOR GAS STORAGE INVENTORY?

A. As stated on page 8 of Equitable Statement No. 4, the $75,175,769 claim for Gas Storage Inventory in the filing was calculated based upon a 13 month average balance of gas, using December 2007 through April 2008 actual balances and estimates for May 2008 through December 2008.

Q. WHAT DO YOU RECOMMEND CONCERNING THIS $75,175,769 CLAIM FOR GAS STORAGE INVENTORY?

A. Given the updated actual costs identified in the Company response to OTS-RB-15-D, I recommend that the $75,175,769 be reduced by $12,815,557 to $62,360,212.

Q. HOW DID YOU DETERMINE THE APPROPRIATED LEVEL OF GAS STORAGE INVENTORY TO BE $62,360,212?

A. Time has passed since the Company compiled the filing of this base rate case and now additional months of actual gas in storage balances are known. The Company's response to OTS-RB-15-D indicates that the 13 month average should include the updated amounts for Gas Storage Inventory (OTS Ex. No. 5, Sch. 2). The updated $62,360,212 reflects the actual balance of Gas Storage Inventory from June 2007 through June 2008 and indicates that the average monthly balance for gas inventory of $75,175,769 should be reduced by $12,815,557 to $62,360,212 as shown on line 15 of OTS Exhibit No. 5, Schedule 3.

<u>CUSTOMER DEPOSITS</u>

Q. DOES THE $583,252,589 MEASURE OF VALUE (RATE BASE) AMOUNT INCLUDE A DEDUCTED CLAIM FOR CUSTOMER DEPOSITS?

A. Yes. The $583,252,589 rate base claim includes a deduction for customer deposits in the amount of $3,369,694 (Equitable Exhibit I, Item I-A-2, Sheet 2 of 3).

Q. **WHAT DO YOU RECOMMEND CONCERNING THIS $3,369,694 CLAIM FOR CUSTOMER DEPOSITS?**

A. Given the updated actual monthly balances identified in the Company responses to OTS-12-D and OTS-25-D, I recommend that the $3,369,694 be increased by $164,315 to $3,534,009.

Q. **HOW DID YOU DETERMINE THE APPROPRIATED LEVEL OF CUSTOMER DEPOSITS TO BE $3,534,009?**

A. Time has passed since the Company compiled the filing of this base rate case and now additional months of actual monthly balances of Customer Deposits are known. The Company's responses to OTS-12-D and OTS-25-D indicate that the 13 month average should include the updated amounts for Customer Deposits (OTS Ex. No. 5, Sch. 4). The updated $3,534,009 reflects the actual balance of Customer Deposits from June 2007 through June 2008 and indicates that the average monthly balance for Customer Deposits of $3,369,694 should be increased by $164,315 to $3,534,009 as shown on line 15 of OTS Exhibit No. 5, Schedule 5.

Post Future Test Year Plant Additions

Q. **WHAT ARE POST FUTURE TEST YEAR PLANT ADDITIONS?**

A. Post Future Test Year Plant Additions are budgeted projected construction projects started and completed after the end of a company's future test year, and therefore, by definition are not actually used and useful in the provision of utility service at the end of the future test year.

Q. DOES THE $583,252,589 RATE BASE INCLUDE A CLAIM FOR POST FUTURE TEST YEAR PLANT ADDITIONS?

A. Yes. The claim includes $13,151,140 in Post Future Test Year Plant Additions. This $13,151,140 represents plant that the Company projects will be installed between January 1, 2009 and June 30, 2009 (OTS Ex. No. 3, Sch. 6).

Q. HOW DID EQUITABLE ESTIMATE ITS CLAIM FOR POST FUTURE TEST YEAR ADDITIONS?

A. The $13,151,140 claimed amount is an estimate of plant additions the Company represents it plans to install between January 1, 2009 and June 30, 2009. While there are no specific projects, the Company claims that 62% ($8,115,760 / $13,151,140)[3] of the $13,151,140 is comprised of projected Main and Service replacements (OTS Ex. No. 5, Sch. 6, p. 3). The $13,151,140 represents plant that will not be used and useful at December 31, 2008, the end of the Company's future test year.

[3] FERC Accounts 376 Mains and 380 Services.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S POST FUTURE TEST YEAR PLANT ADDITIONS?

A. Based upon advice of counsel that plant must be "used and useful" in order to be properly included in a public utility's rate base claim, I recommend that the Commission disallow this claim for Post Future Test Year Plant Additions of $13,151,140 from the Company's Measure of Value.

Q. WHY DO YOU RECOMMEND THAT THE COMMISSION DISALLOW THE COMPANY'S CLAIM FOR POST FUTURE TEST YEAR PLANT ADDITIONS?

A. The Post Future Test Year Plant will not be used and useful at the end of the future test year. The Company has selected December 31, 2008 as the end of its future test year. It is at this point that the revenues and expenses are annualized and normalized, and an appropriate rate of return is applied to the measure of value to determine a level of income that the Company is provided the opportunity to recover through rates. This claim by the Company is already based on projected additions for the period January 1, 2008 through December 31, 2008 which matches the future test year. If the Post Future Test Year Plant Additions are allowed, there will be a mismatch between the measure of value and the other items used to determine the amount of revenue the Company will have the opportunity to recover in rates.

Q. HOW DOES INCLUDING POST FUTURE TEST YEAR PLANT ADDITIONS CREATE A MISMATCH BETWEEN THE MEASURE OF VALUE AND OTHER ITEMS USED TO DETERMINE THE APPROPRIATE REVENUE LEVEL?

A. Such a mismatch will occur because the Post Test Year Plant Additions are for plant installed after December 31, 2008. The balance of the net plant, depreciation expense, revenues, other operating expenses, taxes, and a reasonable rate of return are all based on data as of December 31, 2008, or the future test year ending December 31, 2008. Since these items change over time, using a different time period creates a mismatch.

Q. DOES THE COMMISSION EVER ALLOW ADDITIONS TO THE MEASURE OF VALUE FOR PLANT NOT USED AND USEFUL AT THE TEST YEAR END?

A. In certain cases, the Commission may allow claimed expenditures to complete Construction Work in Progress (CWIP) for plant that will not be completed, i.e. used and useful at the end of the future test year in rate base. However, in those circumstances, to be considered CWIP, construction of the specific project has been required to be "in progress" during the future test year, and "in service" shortly thereafter. Examples of such projects would be buildings, dams or treatment plants.

Q. SHOULD THE $13,151,140 IN POST FUTURE TEST YEAR PLANT ADDITIONS CLAIMED BY EQUITABLE BE CONSIDERED AS CWIP?

A. No. The Post Future Test Year Plant Additions claimed by Equitable are simply budgeted amounts of plant additions the Company claims it will make. They do not represent CWIP since they will not be "in progress" prior to the end of the future test year nor will they be "in service" shortly thereafter.

Q. HAS THE COMMISSION PREVIOUSLY RULED CONSISTENT WITH YOUR POSITION IN THIS PROCEEDING THAT POST FUTURE TEST YEAR PLANT ADDITIONS ARE NOT TO BE INCLUDED IN RATE BASE?

A. Yes. The Commission determined that National Fuel Gas Distribution Corporation, (NFGDC), was not permitted to include Post Future Test Year Plant Additions in its Measure of Value. See: Pennsylvania Public Utility Com'n v. National Fuel Gas Distribution Corp., 86 Pa. P.U.C. 262, 1994 WL 776955, docketed at R-00942991.

Q. DOES THE COMPANY STATE THAT THESE POST FUTURE TEST YEAR PLANT ADDITIONS ARE "NON REVENUE PRODUCING?"

A. Yes. The Company claims that the Post Future Test Pear Plant Additions are "non- revenue producing" (Equitable St. No. 4, p. 6).

Q. IS IT ALSO REASONABLE TO BELIEVE THAT THESE POST FUTURE TEST YEAR PLANT ADDITIONS WILL ALSO REDUCE EXPENSES?

A. Yes. Although the Company did not address this issue, it is reasonable to believe that these Post Future Test Year Plant Additions are being made to reduce expenses. As described above, this creates a mismatch in the rate making equation between the measure of value and expenses.

Q. CAN YOU PROVIDE EXAMPLES OF HOW PLANT ADDITIONS CAUSE EXPENSES TO BE REDUCED?

A. Yes. The largest components of the Company's Post Future Test Year Plant Addition claim are $6,425,760 for Mains and $1,690,000 for Services (OTS Ex. No. 5, Sch. 9, p. 4, lns. 10 and 12). New mains and service are more reliable, are less likely to fail, and require less valve maintenance work. New, more reliable mains and services will reduce the number of leaks and possible fires and/or explosions for which companies are sometimes determined to be liable. New mains and services would therefore tend to reduce the corresponding liability associated with failures, lead to lower property damage claims, insurance expense, and reduce the number and cost of work crews, lowering labor expense.

Another Post Future Test Year project is the $1,000,000 for Software. It is reasonable to believe that new software will be an improvement over the old software, possibly requiring fewer employees, improving overall system operations, and reducing cost. Otherwise the Company would not be replacing the old software.

Q. HAS THE COMPANY REFLECTED ANY REDUCTION IN EXPENSES RELATED TO THESE POST FUTURE TEST YEAR PLANT ADDITIONS BEING PLACED INTO SERVICE?

A. No claim has been made by the Company to reflect any reduction in expenses after these additions are complete. As described above, this failure to reduce expenses results in a mismatch that precludes the allowance of the post future test year plant additions claim.

Post Future Test Year Annual Depreciation Expense

Q. WHAT IS ANNUAL DEPRECIATION EXPENSE?

A. Annual depreciation expense is an operating expense. As noted in the Uniform System of Accounts prescribed for natural gas companies under the Code of Federal Regulations, annual depreciation expense represents the loss of service value of plant in service that is not restored by current maintenance, incurred in connection with consumption not covered by insurance.[4]

[4] Code of Federal Regulations, Title 18, Volume 1, Part 201, Page 507.

Q. HOW HAS EQUITABLE DEVELOPED ITS CLAIM FOR ANNUAL DEPRECIATION EXPENSE AND SALVAGE EXPENSE IN THIS PROCEEDING?

A. The Company has prepared schedules to support its total depreciation expense of $25,017,503. This amount includes $23,836,313 related to plant in service as of December 31, 2008, $639,933 related to Post Future Test Year Plant Additions, and $541,257 of net salvage, (OTS Ex. No. 5, Sch. 8, col. B, lns. 1 through 5).

Q. SHOULD THERE BE A CORRESPONDING REDUCTION IN THE ANNUAL DEPRECIATION EXPENSE CLAIM IF THE COMMISSION DISALLOWS THE POST FUTURE TEST YEAR PLANT ADDITIONS?

A. Yes, if the Commission disallows the $13,151,140 of Post Future Test Year Plant Additions claimed by Equitable and included in its measure of value, there should be a corresponding decrease in the annual depreciation expense of $639,933 (OTS Ex. No. 5, Sch. 8, col. C, ln. 2).

Q. WHY DO YOU RECOMMEND THAT THE ANNUAL DEPRECIATION EXPENSE BE REDUCED BY $639,933?

A. As described above, annual depreciation expense represents that loss of service value of plant in service. This $693,933 is the annual depreciation expense on plant that will not be in service at the end of the future test year. If this amount is included in the annual depreciation expense total, the Company will be improperly recovering annual depreciation expense on plant that is not in service at the end of the future test year. It is therefore my opinion that the Company should not be permitted to include this annual depreciation expense in the determination of the amount of revenue the Company is given the opportunity to receive through rates.

WEATHER NORMALIZATION

Q. WHAT IS MEANT BY THE TERM "WEATHER NORMALIZATION"?

A. This term describes a methodology used to restate historic test year actual sales on a per customer basis to reflect the level of sales that the utility would have achieved had actual heating or cooling degree days been what is considered "normal".

Q. PLEASE EXPLAIN THE TERM "HEATING DEGREE DAY"?

A. The term "heating degree day" represents the variance from 65° Fahrenheit from the mean temperature for the day. The mean temperature for the twenty-four hour period is the sum of the high temperature plus the low temperature divided by two (2). For example, if the high temperature for the day is 28° and the low temperature is 2° the mean for the day is 15° (28° + 2°)/2 = 15°. When the 15° mean temperature for the day is compared to 65° Fahrenheit the result is 50 heating degree days (65° - 15° = 50). The 65° Fahrenheit figure has been used as the standard for computing heating and cooling degree days by the U.S.

Department of Commerce's National Oceanic and Atmospheric Administration ("NOAA") for decades.[5]

Q. PLEASE EXPLAIN THE TERM "NORMAL" AS IT RELATES TO HEATING DEGREE DAYS.

A. The term "normal" when used in relationship to a weather normalization calculation refers to the level of heating or cooling degree days averaged over a period of time. The standard has historically been the 30 year average calculated and published by NOAA. The current 30 year average is based on the years 1971 through 2000.[6] For example, if 5,465 actual heating degree days occurred in the historic test year and the normal level of heating degree days is 5,950, the test year is considered to have been warmer than normal by 485 (5,950 – 5,465) heating degree days. That is to say that had the weather been normal from a heating degree day standpoint; the utility would have realized a higher level of retail sales during the historic test year. The converse is also true; if the historic test year level of actual heating degree days exceeds the normal level then the utility's historic test year sales were higher than otherwise would have occurred because the temperature was colder than normal.

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[5] See for example the *U.S. Monthly Climate Normals 1971 – 2000,* published by NOAA which provides an overview of its process for calculating weather normals.

[6] Id.

Q. HOW IS THE "NORMAL" LEVEL OF HEATING DEGREE DAYS COMPILED?

A. This data is compiled by the NOAA and is defined as follows:

> "Methodology: Normals have been defined as the arithmetic mean of a climatological element computed over a long time period. International agreement eventually led to the decision that the appropriate time period would be three consecutive decades."[7]

It should be noted that a "climate normal" is simply the arithmetic average of the values over a 30-year period, and may or may not be what one would expect to occur on an annual basis.

Q. WHAT DATA IS REQUIRED TO CALCULATE WEATHER NORMALIZED SALES?

A. To calculate weather normalized sales the following data is required:

1) The number of customers by month for each month of the historic test year,

2) The actual sales to the customers in (1) above for the historic test year,

3) The base, non-temperature sensitive load of the customers in (1) above for the historic test year,

4) The actual monthly heating degree days for each month of the historic test year,

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[7] Id.

5) The monthly normal heating degree days for each month.

Q. PLEASE EXPLAIN WHAT IS MEANT BY THE BASE LOAD OF CUSTOMERS.

A. *The base load of customers is the monthly usage of each customer that is* considered to be unaffected by a change in temperature for the purposes of the weather normalization calculation. A customer's base load usage represents the amount of gas used to operate appliances such as a water heater, clothes dryer, kitchen range and oven or an outside post lamp. Generally, the base load usage is the average usage per customer for the months of the historic test year during which zero or only a very few normal heating degree days occur. The base load usage is excluded from the weather normalization calculation because it is assumed to be non-weather sensitive.

Q. PLEASE EXPLAIN HOW THE BASE LOAD IS EXCLUDED FROM WEATHER NORMALIZATION.

A. For each month, individually, the base load is subtracted from the actual sales volumes to derive the weather sensitive load. This will eliminate certain months of the year (normally July and August) from further calculations as it is highly unlikely that there will be any weather sensitive load within these months.

Q. ARE EQUITABLE'S SALES CUSTOMER CLASSES WEATHER SENSITIVE?

A. Yes. Equitable has a high concentration of heating customers whose heating load is greatly affected by the weather. These weather sensitive customers include residential, commercial, and industrial classes.

Q. DID EQUITABLE INCORPORATE A WEATHER NORMALIZATION ADJUSTMENT INTO ITS BASE RATE FILING?

A. Yes. In developing sales, the Company factored its version of normal heating degree days into its forecasting methodology.

Q. WHAT IS THE NUMBER OF HEATING DEGREE DAYS USED BY EQUITABLE IN ITS PROPOSED WEATHER NORMALIZATION ADJUTSMENT?

A. The Company used 5,541 heating degree days (Equitable St. No. 3, p. 7).

Q. WHAT IS THE BASIS FOR THE 5,541 HEATING DEGREE DAYS?

A. The 5,541 heating degree days is the average of monthly actual heating degree days over the past 20 years (1988 – 2007). Equitable's claim is based on a simple average of monthly heating degree days measured over the past 20 years obtained from the NOAA through its weather station located at the Pittsburgh International Airport ("PIT") (OTS Ex. No. 5, Sch. 10).

Q. **DO YOU AGREE WITH THE USE OF A 20-YEAR AVERAGE OF HEATING DEGREE DAYS TO DETERMINE PRESENT RATE REVENUES IN THIS PROCEEDING?**

A. No, I do not.

Q. **WHAT IS YOUR RECOMMENDATION?**

A. I recommend the NOAA 30-year average of heating degree days be used to establish present rate revenues in this proceeding.

Q. **WHAT IS THE VALUE FOR THE NOAA 30-YEAR AVERAGE OF HEATING DEGREE DAYS THAT YOU PROPOSE TO USE IN THIS PROCEEDING?**

A. The officially calculated NOAA 30-year average for PIT is 5,829 heating degree days for 1971 – 2000. However, the Company has provided OTS with the data to calculate the rolling NOAA 30-year average for 1978 – 2007, which produces a value of 5,678 heating degree days. Since the rolling 30-year average uses the most recent 30-year data, I support the use of 5,678 heating degree days.

Q. **WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE NOAA 30-YEAR AVERAGE?**

A. While the United Nation's World Meteorological Organization (WMO) requires the calculation of normals every 30 years, with the latest covering the 1961 through 1990 period, the United States updates its normals at the completion of each decade, with the latest covering the 1971 through 2000 period.[8] NOAA has been using this standard since 1956 when its first set of normals were published.[9] To the best of my knowledge, NOAA continues to use the 30-year average, and continues to base heating degree days on a base temperature of 65° Fahrenheit. My recommendation to use the most recent 30-year average (1978 – 2007) in this proceeding is consistent with this 30-year standard.

Q. HAVE YOU PREPARED A WEATHER NORMALIZATION ADJUSTMENT?

A. Yes. I have prepared a weather normalization adjustment for the RS – Residential Service, GSS – General Service Small, and GSL – General Service Large rate classes. The results of this analysis are summarized in OTS Exhibit No. 5, Schedule 11. The detailed calculation of these adjustments is presented in OTS Exhibit No. 5, Schedule 12 through Schedule 17.

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[8] National Oceanic and Atmospheric Administration, *U.S. Monthly Climate Normals 1971-2000*, Overview.
[9] Id.

AVERAGE USE PER RS - RESIDENTIAL SERVICE CUSTOMER

Q. WHAT AVERAGE NORMALIZED USAGE DID THE COMPANY USE TO PROJECT THE TOTAL USAGE FOR THE RESIDENTIAL HEATING CLASS?

A. The Company used 88.94 Mcf per residential heating customer to determine normalized usage for the RS class (18,325,043 Mcf / 206,044 customers) (OTS Ex. No. 5, Sch. 12, p. 1 of 3, col. D, ln. 1).

Q. DID THE COMPANY PROVIDE THE ACTUAL SALES VOLUMES FOR THE RESIDENTIAL HEATING CLASS FOR EACH MONTH OF 2007?

A. Yes. Item 6 of Equitable Exhibit VI, Volume 1 of 3 contains the actual sales volumes from January 2007 through December 2007.

Q. BASED ON THE ACTUAL NUMBER OF CUSTOMERS AND MONTHLY SALES VOLUMES, WERE YOU ABLE TO DETERMINE THE BASE LOAD FOR EACH RESIDENTIAL HEATING CLASS CUSTOMER?

A. Yes. Reviewing the actual sales volumes for the residential heating class for 2007, I agreed with the Company in determining that the least amount of gas was used in the months of July and August. Dividing the monthly sale for these months by the number of customers, I determined that the average base load for each residential heating customer is approximately 1.6 Mcf per month as shown on OTS Exhibit No. 5, Schedule 14, column E, line 20 (664,871 / 415,603 = 1.6).

Q. USING THE AVERAGE BASE LOAD PER CUSTOMER FOR 2007, WERE YOU ABLE TO DETERMINE THE 2008 BASE LOAD FOR EACH RESIDENTIAL HEATING CLASS CUSTOMER?

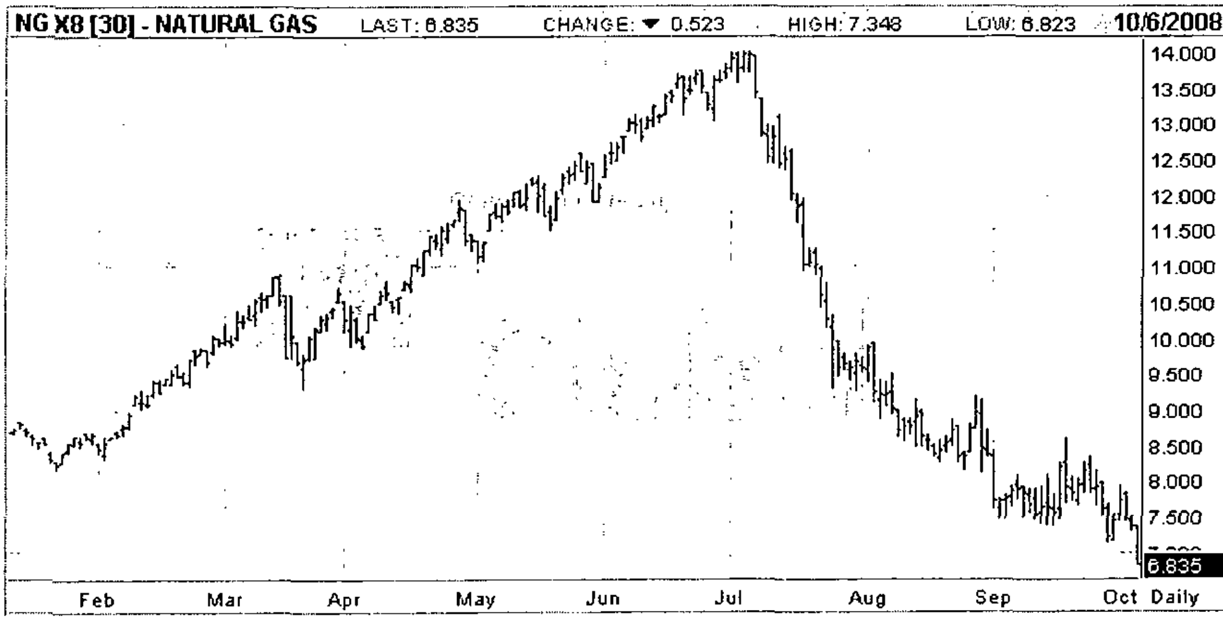
A. Yes. The total base load for the residential heating class is the estimated number of customers each month of 2008 multiplied by the 2007 average base load for the residential heating class. The base load each month is shown under column C of OTS Exhibit No. 5, Schedule 15.

Q. PLEASE DESCRIBE THE REMAINING COLUMNS ON OTS EXHIBIT NO. 5, SCHEDULE 15.

A. The heat factor is shown under column D and is the 2007 normalized temperature sensitive load under column I of Schedule 14 divided by the product of the number of customers for each month of 2007 and the rolling NOAA 30-year normal heating degree days under column E. The normal heating degree days under column E were obtained from the NOAA, as explained previously. The normalized temperature sensitive load under column F is the product of the 2008 number of customers for each month, the heat factor for each month, and the normal number of heating degree days each month. The normalized loads under column I is the base load under column C plus the normalized temperature sensitive load under column I except for the months of June, July, and August which are the actual sales under column C.

Q. THE COMPANY HAS CLAIMED A ONE PERCENT CONSERVATION ADJUSTMENT IN THE CALCULATION OF THE NORMALIZED LOAD FOR THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. According to the Company, the normalized heating sales for 2008 should include an estimated one percent reduction to account for high natural gas prices and increased conservation efforts (OTS Ex. No. 5, Sch. 18). This adjustment is purely speculative and should not be included when calculating the normalized load for the future test year for two reasons. First, as can be seen in the following chart provided by FutureSource.com, the price per dekatherm of natural gas has fallen by 49 % since the beginning of July from $13.500 / Dth to $6.835 / Dth on October 6, 2008. Secondly, customers are just as likely to increase natural gas usage by replacing electric stoves and water heaters with gas appliances as the price of electricity is expected to increase mitigating the speculative loss that the Company believes will occur.



Q. USING THE AVERAGE BASE LOAD PER CUSTOMER, WERE YOU ABLE TO DETERMINE THE AVERAGE ANNUALIZED NORMALIZED SALES FOR EACH RESIDENTIAL HEATING CLASS CUSTOMER?

A. Yes. Dividing the total normalized usage of 18,847,600 Mcf shown on OTS Exhibit No. 5, Schedule 15, column I, line 13 by the average 206,044 customers shown under column B, line 14, I determined that the total annual normalized usage for January 2008 through December 2008 was 91.47 Mcf per customer (OTS Ex. No. 5, Sch. 15, col. E, ln. 16).

Q. HOW DOES THIS 91.47 MCF COMPARE TO WHAT THE COMPANY CLAIMED?

A. The difference between the two amounts is 2.53 Mcf (91.47 Mcf – 88.94 Mcf), as shown on OTS Exhibit No. 5, Schedule 12, page 1 of 3, columns D and G, line 1.

Q. WHAT IS THE INCREASE IN PRESENT REVENUES IF THE AVERAGE USAGE PER RESIDENTIAL HEATING CUSTOMER IS INCREASED FROM 88.94 MCF TO 91.47 MCF PER YEAR?

A. Increasing the average use per residential heating customer to 91.47 Mcf per year increases the present revenues for the residential heating class by $9,134,291, as shown on OTS Exhibit No. 5, Schedule 12, page 1 of 3, column J, line 12.

Q. IF THE COMMISSION ACCEPTS THIS $9,134,291 INCREASE IN PRESENT REVENUES, SHOULD THERE ALSO BE A CORRESPONDING INCREASE IN THE COST OF GAS?

A. Yes, there should be. I have calculated the increase to purchased gas costs by multiplying the projected sales increase of 522,557 Mcf (18,847,600 – 18,325,043 Mcf) times the 1307(f) base cost of gas of $13.97 utilized by the Company to develop its purchased gas cost claim.

Q. WHAT IS THE CORRESPONDING INCREASE IN THE COST OF GAS?

A. If the Commission accepts this present revenue adjustment, there should be a corresponding increase of $7,300,117 in the cost of gas, as shown on OTS Exhibit No. 5, Schedule 12, page 1 of 3, column J, line 10.

AVERAGE USE PER GSS – GENERAL SERVICE SMALL CUSTOMERS

Q. WHAT AVERAGE NORMALIZED USAGE DID THE COMPANY USE TO PROJECT THE TOTAL USAGE FOR THE GSS HEATING CUSTOMER CLASS?

A. The Company used 205.55 Mcf per GSS heating customer (2,786,472 Mcf / 13,556 customers) (OTS Ex. No. 5, Sch. 12, p. 2 of 3, col. D, ln. 1).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATIONS TO INCREASE THE AVERAGE USAGE FOR RESIDENTIAL HEATING CUSTOMERS SHOULD THE AVERAGE USAGE FOR GSS – GENERAL SERVICE SMALL HEATING CUSTOMERS ALSO BE ADJUSTED?

A. Yes. The average usage for GSS customers should be increased approximately 3.65 Mcf to 209.20 Mcf, as shown on OTS Exhibit No. 5, Schedule 12, page 2 of 3, line 1. The corresponding increase in present revenue should be $835,921 as shown under column J, line 11, and the increase in the cost of gas should be $691,936 as shown on line 9. The reasons for these adjustments are described above.

AVERAGE USE PER GSL – GENERAL SERVICE LARGE CUSTOMERS

Q. WHAT AVERAGE NORMALIZED USAGE DID THE COMPANY USE TO PROJECT THE TOTAL USAGE FOR THE GSL HEATING CUSTOMER CLASS?

A. The Company used 2,126.94 Mcf per GSL heating customer (1,435,508 Mcf / 675 customers) (OTS Ex. No. 5, Sch. 12, p. 3 of 3, col. D, ln. 1).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATIONS TO INCREASE THE AVERAGE USAGE FOR RESIDENTIAL AND GSS HEATING CUSTOMERS SHOULD THE AVERAGE USAGE FOR GSL – GENERAL SERVICE SMALL HEATING CUSTOMERS ALSO BE ADJUSTED?

A. Yes. The average usage for GSL customers should be increased approximately 35.21 Mcf to 2,162.15 Mcf, as shown on OTS Exhibit No. 5, Schedule 12, page 3 of 3, line 1. The corresponding increase in present revenue should be $396,405 as shown under column J, line 12, and the increase in the cost of gas should be $332,001 as shown on line 10. The reasons for these adjustments are described above.

<u>CUSTOMER COST ANALYSIS</u>

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

A. A customer cost analysis is part of a cost of service study that includes only customer costs. It is used to determine the appropriate customer charges for the various classes.

Q. DID THE COMPANY PREPARE A CUSTOMER COST ANALYSIS TO SUPPORT INCREASING THE CUSTOMER CHARGES?

A. Yes. The Company completed its Customer Cost Analysis which is presented in Equitable Exhibit IV, Item IV-B-9. Based on this analysis, the Company claims that it incurs $36.23 per month in customer costs for each RS – Residential Service customer, $32.87 per month in customer costs for each GSS-General Service Small customer, and $288.18 per month in customer costs for each GSL – General Service Large customer.

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED WHAT ITEMS SHOULD BE RECOVERED IN A CUSTOMER CHARGE?

A. Yes. In PAWC case, at Docket No. R-00093270 (Order entered July 26, 1994), the Commission stated that "customer charges appropriately recover billing and collection costs, meter reading costs, and costs of meters and services" (Order pages 111-115). These are direct customer costs and the Commission's listings of these items appeared to preclude the inclusion of other items in the determination of a customer charge.

Q. HAS THE COMMISSION RECENTLY MODIFIED THE REQUIREMENT THAT THE CUSTOMER CHARGE ONLY RECOVER DIRECT CUSTOMER COSTS?

A. Yes. In an Aqua Pennsylvania base rate case, at Docket No. R-0038805 (Order entered August 5, 2004), the Commission modified the requirement and found that indirect costs such as customer equipment (computers), meter and service line maintenance, as well as payroll taxes and benefits should be recovered in the customer charge. The Commission also found that other indirect costs such as employee benefit costs, local taxes and other general and administrative costs could be recovered in a customer charge, but the inclusion of these costs in future cases would be on a case by case basis (Aqua Order p. 72). In another proceeding, the Commission found that uncollectible account expense is an indirect customer cost (PPL Gas Utilities, Inc., Docket No. R-00061398, Order entered February 8, 2007, p. 130).

Q. WHAT ITEMS DID THE COMPANY INCLUDE IN ITS CUSTOMER COST STUDY?

A. As shown on Equitable Exhibit IV, Item IV-B-9(A), the Company has included maintenance expenses, mains & services expenses, meter expenses, the depreciation expense, additional expenses, uncollectible account expense, operating and maintenance expenses, and return dollars and income taxes on mains, meters and services. Operating and maintenance expenses are broken down into distribution expenses, administrative and general expenses, taxes, demonstration expense, advertising expense, and customer assistance and informational expense as can be seen on Sheets 60-62 and Sheets 68-70 of Equitable Exhibit IV, Item IV-B-1.

Q. SHOULD THE COMPANY HAVE INCLUDED ALL OF THE ITEMS LISTED ABOVE TO DETERMINE THE COSTS THAT SHOULD BE RECOVERED IN THE CUSTOMER CHARGE?

A. No. The Company should have only included direct customer costs and the indirect customer costs that the Commission previously determined could be recovered in a customer cost analysis to determine an appropriate customer charge. Direct customer costs are those items it must have in place to serve customers each month. These costs increase each time a new customer is added, or decreases when a customer is lost. Indirect customer costs include costs that do not change if one customer joins or leaves the system, but could be considered customer related costs incurred in the provision of service.

Q. HAVE YOU CALCULATED WHAT THE MONTHLY CHARGES SHOULD BE FOR EQUITABLE?

A. Yes. Using the average number of bills shown on Equitable Exhibit IV, Item IV-B-9(B), Sheet 1 of 4, I compiled a customer cost analysis. Based on my customer cost analysis, I determined that the Company incurs $21.97 per month in customer costs for each RS – Residential Service customer, $14.52 per month in customer costs for each GSS-General Service Small customer, and $187.14 per month in customer costs for each GSL – General Service Large customer (OTS Ex. No. 5, Sch. 19, p. 1 of 5, ln. 19).

Q. WHAT ITEMS DID YOU INCLUDE IN YOUR CUSTOMER COST ANALYSIS TO DETERMINE THE APPROPRIATE CUSTOMER CHARGE?

A. I included the following direct customer costs: meter expenses, expenses for meter reading and customer records & collection, depreciation expense for meters and services, and the rate base related return and taxes for the meters and services. I also included the following indirect customer costs: uncollectible accounts expense, meter maintenance expense, supervision & engineering maintenance related to distribution expenses, customer assistance and informational expense, and expenses for injuries and damages and employee pensions and benefits.

Q. DID YOU ALSO INCLUDE OTHER REVENUE RECEIVED BY THE COMPANY IN YOUR CUSTOMER COST ANALYSIS THAT WOULD REDUCE COSTS?

A. Yes. If the Company is permitted to claim uncollectible accounts expense as an indirect customer cost, I believe it is also reasonable to include other revenue that the Company receives to offset the direct and indirect customer costs in the customer cost analysis.

Q. HOW MUCH OTHER REVENUE DID YOU INCLUDE IN YOUR CUSTOMER COST ANALYSIS?

A. I included $2,827,000 of other revenue to offset the other customer costs in my customer cost analysis comprised of billing and collecting revenue and other customer related revenue to offset the direct and indirect customer costs (OTS Ex. No. 5, Sch. 19, p. 1 of 5, lns. 13-16).

Q. WHY DO YOU RECOMMEND THAT THE OTHER ITEMS CLAIMED BY THE COMPANY BE REMOVED?

A. The other items claimed by the Company are indirect customer costs that are not recovered through the customer charge, or not even customer cost related. For example, expenses related to distribution mains are neither direct nor indirect customer costs. The Commission has previously determined in a 1994 Opinion and Order in the Pennsylvania American Water Company case at Docket No. R-00932670, Order entered July 26, 1994, at pages 111- 115, that direct customer costs include "the depreciation, return and income taxes associated with meter and service investment, the operation and maintenance expense for meters and services, and the expense associated with meter reading and billing". Mains are not included in any of these categories, and therefore should not be considered or classified as a customer cost. The basis for this determination is that the quantity and investment in mains does not change significantly if one customer joins or leaves the system. Mains are built to deliver gas, and the cost of mains cannot be assigned to one specific customer. Therefore, no portion of the fixed costs or depreciation expense associated with mains should be allocated to the customer cost function. The cost of the outside services employed allocated to the customer function under administrative and general expenses could be considered an indirect customer cost. However, because general and administrative costs do not generally vary by the number of customers served and those costs were not included in the list of expenses that the Commission found should always be recoverable in the customer charge, I did not include the costs of outside services employed in my customer cost analysis.

CUSTOMER CHARGES

Q. IS EQUITABLE PROPOSING TO INCREASE THE RS - RESIDENTIAL SERVICES CUSTOMER CHARGE?

A. Yes. The Company is proposing to increase the Residential Service customer charge from $11.65 per month to $20.00 per month which is an increase of 71.7% (OTS Ex. No. 5, Sch. 20, col. K, ln. 2).

Q. WHAT IS EQUITABLE'S JUSTIFICATION FOR THE INCREASE IN THE PROPOSED CUSTOMER CHARGE?

A. The claimed basis for increasing all customer charges is the Company's over inclusive customer cost analysis. The Company claims that this is an effort to move the Rate Schedule RS customer charge closer to the Company's calculated cost of $36.23 per month. Equitable claims that the $20.00 customer charge will recover approximately 58 % of its residential customer costs (Equitable St. No. 1, p. 20).

Q. ARE YOU OBJECTING TO THE COMPANY'S PROPOSED CUSTOMER COST CALCULATION FOR RATE RS?

A. Yes, I am.

Q. WHAT IS THE BASIS FOR YOUR OBJECTION?

A. I am objecting to Equitable's proposed customer charge for several reasons: (1) Equitable's proposed customer charge is excessive and violates gradualism; (2) Equitable's calculation of costs which support the customer charge increase contains cost items that should be and/or have been disallowed by the Commission in previous cases, and (3) Equitable's customer charge would be, by a significant measure, the highest customer charge of any LDC in Pennsylvania.

Q. WOULD YOU DEFINE THE PRINCIPLE OF GRADUALISM IN RATE DESIGN?

A. The principle of gradualism in rate design is the avoidance of rate shock in the setting of rates. Gradualism is a well established ratemaking concept that limits the increase customers receive when rates are increased.

Q. HAVE YOU DONE A COMPARISON OF OTHER LDC MONTHLY CUSTOMER CHARGES IN PENNSYLVANIA?

A. Yes, I have. My analysis revealed that some examples of LDC customer charges are as follows:

LDC	Monthly Customer Charge
T.W. Phillips	$12.50
National Fuel Gas Dist. Corp.	$12.00
PPL Gas Utilities	$12.00
Philadelphia Gas Works	$12.00
Dominion Peoples	$11.00
Columbia Gas of PA Inc.	$10.81
UGI Utilities Inc.	$8.55
PECO Energy Company	$7.20

Q. WHAT CUSTOMER CHARGE DO YOU RECOMMEND FOR RS - RESIDENTIAL SERVICE CUSTOMERS?

A. I recommend that the RS – Residential Service customer charge be increased to $15.00 per month, which is an increase of $3.35 or 28.8%.

Q. HOW DID YOU DETERMINE A CHARGE OF $15.00 PER MONTH?

A. Since I have determined that $21.97 is the proper amount of Rate RS customer costs, $15.00 would be approximately 68.3% of customer costs, which moves the customer charge significantly towards full cost recovery.

Q. ARE YOU PROPOSING AN ADJUSTMENT TO THE DELIVERY CHARGE FOR RATE RS?

A. Yes, I am. Equitable's Rate RS delivery charge should be increased from $2.703 to $3.378 per Mcf, or an increase of 22.8% (OTS Ex. No. 5, Sch. 20,col. L, ln. 3). This increase in the commodity charge allows the customer charge to be set at the appropriate level without affecting the Company's proposed total revenue for Rate RS of $384,986,025.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE EFFECT ON CUSTOMER'S BILLS AT THE COMPANY'S PROPOSED RATES AND THE OTS'S PROPOSED RATES?

A. Yes, I have. The comparison is shown on OTS Exhibit No. 5, Schedule 21.

Q. WHAT DOES THIS SCHEDULE SHOW?

A. This schedule shows that for a customer using 0 to 7 Mcf per month, the actual dollar and percentage increases are less under my proposal as compared to that of the Company. Based on the Company's bill frequency analysis for Rate RS in Equitable Exhibit IV, Item IV-B-5, this encompasses approximately 72 % of customer bills. Only at the higher monthly usage levels would the results of the OTS recommendation on customer bills exceed that of the Company.

Q. IS EQUITABLE PROPOSING TO INCREASE THE GSS – GENERAL SERVICE SMALL CUSTOMER CHARGES?

A. Yes. The monthly service charge for customers consuming less than 500 Mcf will increase from $17.00 per meter to $23.00 per meter, while the monthly service charge for customers consuming greater than 500 Mcf will increase from $28.00 per meter to $32.00 per meter (Equitable St. No. 1, p. 24).

Q. **WHAT CUSTOMER CHARGES DO YOU RECOMMEND FOR GSS – GENERAL SERVICE SMALL CUSTOMERS?**

A. I recommend that customer charges for GSS customers remain at current levels, which consists of a service charge of $17.00 per meter if a customer consumes less than 500 Mcf annually and $28.00 per meter if a customer consumes greater than 500 Mcf annually

Q. **WHY DO YOU RECOMMEND THAT THE MONTHLY CUSTOMER CHARGES FOR GSS – GENERAL SERVICE SMALL CUSTOMERS REMAIN AT CURRENT LEVELS?**

A. My customer cost analysis shows that there is no cost of service basis for increasing the GSS monthly customer charges (OTS Ex. No. 5, Sch. 19, p. 1, ln. 19). However, since customers are currently accustomed to paying these customer charges, I do not believe they should be lowered.

Q. **ARE YOU PROPOSING AN ADJUSTMENT TO THE DELIVERY CHARGE FOR RATE GSS?**

A. Yes, I am. Equitable's Rate GSS delivery charge should be increased from $2.737 to $3.151 per Mcf, or an increase of 15.6% (OTS Ex. No. 5, Sch. 20, col. L, ln. 16). This increase in the commodity charge allows the customer charge to be set at the appropriate level without affecting the Company's proposed total revenue for Rate GSS of $51,151,623.

<u>**RATE FDS – FIRM DELIVERY SERVICE**</u>

Q. WOULD YOU ADDRESS THE COMPANY'S FIRM DELIVERY SERVICE TARIFF?

A. Yes I will. The Company has proposed Rate FDS – Firm Delivery Service which will be available for resale service and to any essential human needs customer and any customer who consumes 300 Mcf annually or less, and to any other customer who consumes no more than 5,000 Mcf annually where the customer's full commodity requirements are supplied through a single aggregation pool pursuant to the Company's Firm Pooling Service (FPS) (Equitable Ex. No. IV, Item 53.53 IV-B-6, Supplement No. 60, Gas - Pa. P.U.C No. 22, Seventh Revised Page No. 61).

Q. ARE YOU PROPOSING AN ADJUSTMENT TO THIS TARIFF?

A. Yes, I am. I am recommending that the proposed monthly service charge for Residential customers should be set at $15.00 per meter, the same as the monthly service charge for customers served under Rate RS. This rate should be set equal to the Rate RS – Residential Service customer at whatever level is ultimately determined for that rate. I am also recommending that the proposed monthly service charge for Commercial and Industrial customers that use less than 500 Mcf annually should be set at $17.00 per meter and those that use 500 – 1,000 Mcf annually should be set at $28.00 per meter. These rates should be set equal to the Rate GSS- General Service Small customer at whatever level is ultimately determined for that rate.

Q. WHY ARE YOU RECOMMENDING THESE REVISED MONTHLY SERVICE CHARGES?

A. It is proper to set the monthly service charge for residential firm delivery service at the same rate as the rate for residential sales service since the monthly service charge would be indifferent to both sales and transportation service, in order not to favor one over the other. Also, since firm delivery service to commercial and industrial customers using less than 500 Mcf per year and those using 500 – 1,000 Mcf per year would apply to GSS – General Service Small customers it is likewise appropriate to set the monthly service charges at the same rates as the rates for GSS sales service.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The following is a list of my recommendations:

1. The Company should reflect proposed forfeited discounts revenue equal to 0.419 % of Gas Service Revenues the Company is permitted the opportunity to receive in this case.

2. Rate Base should be reduced by $26,131,011 from $583,252,589 to $557,285,893 reflecting updated gas storage inventory, updated customer deposits, and removal of post future test year additions (OTS Ex. No. 5, Sch. 7).

3. Associated with the removal of the post future test year additions from net plant is a $639,933 reduction to total depreciation and amortization expense (OTS Ex. No. 5, Sch. 8).

4. The throughput projection levels claimed by the Company should be disallowed and be replaced with the OTS adjusted figures using a 30-year weather normalization. The effect of this modification is an increase of $10,366,617 to present rate revenues and an increase to purchased gas costs of $8,324,054 (OTS Ex. No. 5, Sch. 11).

5. Based on the concept of gradualism, the OTS cost of service study for the monthly service charges, and the comparison to other LDC monthly customer charges in Pennsylvania, the monthly service charge for RS – Residential Service customers should be increased from $11.65 to $15.00 and the monthly service charges for GSS – General Service Small customers should remain at current levels.

6. In order to not affect the Company's proposed total revenue for rate classes RS and GSS, the delivery charge for Rate RS should be increased from \$2.703 to \$3.378 and the delivery charge for Rate GSS should be increased from \$2.737 to \$3.151 (OTS Ex. No. 5, Sch. 20).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JEREMY B. HUBERT

PROFESSIONAL EXPERIENCE AND EDUCATION

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Mechanical Engineering, 2003

- Attended EUCI Introduction to Rate Design for Electric Utilities, Philadelphia, PA
- Attended EUCI Introduction to Cost of Service Concepts and Techniques for Electric Utilities, Philadelphia, PA
- Attended NARUC Rate School, San Diego, CA

EXPERIENCE:

11/2006 - Present
Office of Trial Staff, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

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

10/2005 – 11/2006
Pennsylvania Department of Transportation - Harrisburg, Pennsylvania

Materials Technician – Responsible, primarily, for performing a variety of technical duties associated with the routine testing of coarse aggregates according to AASHTO and PTMs.

05/2005 – 10/2005
Gatter & Diehl, Inc. Consulting Engineers - Harrisburg, Pennsylvania

Mechanical Designer – Responsible, primarily, for assisting engineers and CADD technicians in the design aspects of HVAC, plumbing, and fire protection systems.

TESTIMONY SUBMITTED:

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

- Village Water Company, Docket No. R-00072351
- United Water of Pennsylvania, Inc., Docket No. A-210013F0017
- Total Environmental Solutions, Inc.
  Treasure Lake Division, Docket No. R-00072493
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,
  Docket No. R-2008-2012502
- PECO Energy Company, Docket No. R-2008-2028394
- PPL Gas Utility Corporation, 1307(f) proceeding,
  Docket No. R-2008-2039634

OTS Exhibit No. 5
Witness: Jeremy B. Hubert

11/19/08
HBG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Direct Testimony

of

Jeremy B. Hubert

Office of Trial Staff

Concerning:

Forfeited Discounts
Rate Base
Depreciation Expense
Weather Normalization Adjustment
Customer Costs

OTS Exhibit No. 5
Schedule 1

Equitable Gas Company
OTS Annualization of Forfeited Discounts Revenue
Docket No. R-2008-2029325

	Year Ended A		Sales Revenue B	Forfeited Discounts C	Percent FD to Sales Revenue D	
1	12/31/2003	(a)	$328,256,970	$2,300,094	0.701%	
2	12/31/2004	(b)	$359,879,242	$2,499,268	0.694%	
3	12/31/2005	(c)	$401,368,679	$1,731,154	0.431%	
4	12/31/2006	(d)	$378,295,801	$1,577,062	0.417%	
5	12/31/2007	(e)	$382,742,414	$1,557,851	0.407%	
6	Total		$1,850,543,106	$9,665,429	0.522%	5 year average
7			$1,162,406,894	$4,866,067	0.419%	3 year average (2005-2007)
8	12/31/2008	(f)	$423,637,575	$1,557,851	0.368%	at present rates
9	12/31/2008	(f)	$461,611,292	$1,557,851	0.337%	at proposed rates

(a): Gas Annual Report for the Year Ended December 31, 2003, 400. Income Statement - Revenues and Expenses
(b): Gas Annual Report for the Year Ended December 31, 2004, 400. Income Statement - Revenues and Expenses
(c): Gas Annual Report for the Year Ended December 31, 2005, 400. Income Statement - Revenues and Expenses
(d): Gas Annual Report for the Year Ended December 31, 2006, 400. Income Statement - Revenues and Expenses
(e): Equitable Exhibit III, Item III-A-17
(f): Equitable Exhibit III, Item III-E-20, Section II: 1

10 Annualized Forfeited Discounts for the FTY at Proposed Rates = 0.00419 * $461,611,292 = **$1,932,397**

11 Forfeited Discounts adjustment at proposed rates = $1,932,397 - $1,557,851 = **$374,546**

Docket No. R-2008-2029325
Item: OTS-RB-15-D
Respondent: Carol B. Gras
Position: Manager, Planning and Analysis

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RB-15-D

Provide a schedule showing the monthly balances for the Company's gas storage inventory on a dollar value basis and on a Mcf basis for each month starting in December 2004.

Response:

Please refer to the attached spreadsheet for the dollar value balance and Mcf basis for each month from December 2004 through June 2008, the latest month available.

Equitable Gas Company - PA Division - Gas Storage Inventory

OTS Exhibit No. 5
Schedule 2

Month		Balance	Volumes (Mcf)		$ per Mcf
Dec-04	$	63,662,232	9,225,320	$	6.90
Jan-05	$	38,875,094	5,598,026	$	6.94
Feb-05	$	22,991,216	3,266,164	$	7.04
Mar-05	$	5,718,647	724,760	$	7.89
Apr-05	$	14,094,949	1,715,990	$	8.21
May-05	$	26,175,234	3,239,943	$	8.08
Jun-05	$	36,044,563	4,569,975	$	7.89
Jul-05	$	44,452,557	5,921,409	$	7.51
Aug-05	$	57,594,531	7,271,351	$	7.92
Sep-05	$	78,425,084	8,642,028	$	9.07
Oct-05	$	89,503,305	9,864,321	$	9.07
Nov-05	$	95,636,569	9,702,183	$	9.86
Dec-05	$	71,897,967	7,261,331	$	9.90
Jan-06	$	63,333,742	6,358,982	$	9.96
Feb-06	$	47,047,126	4,678,452	$	10.06
Mar-06	$	32,902,159	3,211,943	$	10.24
Apr-06	$	34,388,360	3,461,535	$	9.93
May-06	$	46,223,956	4,947,679	$	9.34
Jun-06	$	57,285,645	6,405,072	$	8.94
Jul-06	$	70,470,853	8,210,119	$	8.58
Aug-06	$	80,162,187	9,352,415	$	8.57
Sep-06	$	96,204,926	11,489,853	$	8.37
Oct-06	$	104,512,055	13,351,861	$	7.83
Nov-06	$	96,735,940	12,344,338	$	7.84
Dec-06	$	88,098,904	11,225,982	$	7.85
Jan-07	$	72,135,532	8,617,472	$	8.37
Feb-07	$	48,060,941	5,761,573	$	8.34
Mar-07	$	34,570,376	4,114,344	$	8.40
Apr-07	$	24,653,898	2,940,597	$	8.38
May-07	$	32,001,847	3,928,171	$	8.15
Jun-07	$	47,849,122	5,645,528	$	8.48
Jul-07	$	64,310,435	7,941,308	$	8.10
Aug-07	$	75,549,986	9,476,021	$	7.97
Sep-07	$	88,141,850	11,404,234	$	7.73
Oct-07	$	97,307,466	12,812,799	$	7.59
Nov-07	$	96,381,266	12,558,110	$	7.67
Dec-07	$	92,072,226	12,005,930	$	7.67
Jan-08	$	70,143,409	8,978,172	$	7.81
Feb-08	$	44,712,754	5,638,044	$	7.93
Mar-08	$	24,168,057	3,136,734	$	7.70
Apr-08	$	23,807,941	2,998,298	$	7.94
May-08	$	37,685,231	3,999,416	$	9.42
Jun-08	$	48,553,013	4,801,215	$	10.11

OTS Exhibit No. 5
Schedule 3

Equitable Gas Company

Gas Storage Inventory

R-2008-2029325

		Company Stored Underground	OTS Stored Underground	OTS Adjustment
1	June, 2007	-	$47,849,122	
2	July	-	$64,310,435	
3	August	-	$75,549,986	
4	September	-	$88,141,850	
5	October	-	$97,307,466	
6	November	-	$96,381,266	
7	December, 2007	-	$92,072,226	
8	January, 2008	-	$70,143,409	
9	February	-	$44,712,754	
10	March	-	$24,168,057	
11	April	-	$23,807,941	
12	May	-	$37,685,231	
13	June, 2008	-	$48,553,013	
14	Total	-	$810,682,756	
15	Average Monthly Balance	$75,175,769 *	$62,360,212	**($12,815,557)**

* **Reference Equitable St. No. 4, page 8**

Docket No. R-2008-2029325
Item: OTS-RB-12-D
Respondent: Carol B. Gras
Position: Manager, Planning and Analysis

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RB-12-D

Reference Company Exhibit I, Item I-A-2, Sheet 2 of 3: Provide the actual balance of Customer Deposits for each month from January 2008 until the latest month available.

Response:

Please refer to the following schedule for the actual balance of customer deposits for each month from January 2008 through June 2008, the latest month available.

	Customer Deposits
Jan-08	$ (3,527,421)
Feb-08	(3,595,878)
Mar-08	(3,669,181)
Apr-08	(3,563,416)
May-08	(3,573,395)
Jun-08	(3,627,300)

Docket No. R-2008-2029325
Item: OTS-RB-25-D
Respondent: Carol B. Gras
Position: Manager, Planning and Analysis

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RB-25-D

Reference the Company's response to OTS-RB-12-D: Provide the actual balance of Customer Deposits for each month from January 1, 2007 through December 31, 2007.

Response:

The actual balances of Customer Deposits for each month from January 1, 2007 through December 31, 2007 are:

	$ Amount
Jan-2007	(4,168,262)
Feb-2007	(4,115,452)
Mar-2007	(4,055,553)
Apr-2007	(3,859,238)
May-2007	(3,735,348)
Jun-2007	(3,641,573)
Jul-2007	(3,569,478)
Aug-2007	(3,447,163)
Sep-2007	(3,473,131)
Oct-2007	(3,404,897)
Nov-2007	(3,364,481)
Dec-2007	(3,484,804)

OTS Exhibit No. 5
Schedule 5

Equitable Gas Company

Future Period - 12 Months Ended December 31, 2008

Customer Deposits

		Company Customer Deposits	OTS Customer Deposits	OTS Adjustment
1	June, 2007	-	$3,641,573	
2	July	-	$3,569,478	
3	August	-	$3,447,163	
4	September	-	$3,473,131	
5	October	-	$3,404,897	
6	November	-	$3,364,481	
7	December, 2007	-	$3,484,804	
8	January, 2008	-	$3,527,421	
9	February	-	$3,595,878	
10	March	-	$3,669,181	
11	April	-	$3,563,416	
12	May	-	$3,573,395	
13	June, 2008	-	$3,627,300	
14	Total	-	$45,942,118	
15	Average Monthly Balance	$3,369,694	$3,534,009	**$164,315**

Docket No. R-2008-2029325
Item: OTS-RB-23-D
Respondent: Carol B. Gras
Position: Manager, Planning and Analysis

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RB-23-D

Reference the Company's response to OTS-RB-3-D: Reconcile the net 2008 plant additions to Account 394 – Tools & Garage Equipment of $177,886 ($490,896 - $313,010) and the amount of ($300,201) calculated to be the difference between the original cost of Account 394 – Tools & Garage Equipment at December 31, 2007, $4,355,038 ($3,876,951 + $478,087), and the original cost of Account 394 – Tools & Garage Equipment at December 31, 2008, $4,054,837, shown in Exhibit I, Volume 1 of 2, I-A-4 (HISTORIC), Sheets 49 and 50 of 146 and I-A-4 (FUTURE), Sheet 4 of 102 respectively.

Response:

The difference of $478,087 represents fully amortized property, which was inadvertently excluded from the future test year retirements for account 394 – Tools & Garage Equipment presented in the Company's response to OTS –RB-3 –D. A revised schedule detailing plant additions and retirements for the future test year ended December 31, 2008 is attached.

Equitable Gas Company - PA Division
Estimated Plant Additions & Retirements by FERC Account
For the Future Test Year Ending December 31, 2008

FERC Acct	Description	Additions 1/1/2008 - 12/31/2008	Retirements 1/1/2008 - 12/31/2008	Non-Revenue Producing 1/1/2009 - 6/30/2009
	INTANGIBLE PLANT			
301	Organization	-	-	-
302	Franchises & Consents	-	-	-
303	Miscellaneous Intangible Plant - Software	1,930,344	(3,637,769)	1,000,000
303	Miscellaneous Intangible Plant - Software (2002 and prior)	-	(1,737,126)	-
	Total Intangible Plant	1,930,344	(5,374,895)	1,000,000
	NATURAL GAS PRODUCTION & GATHERING PLANT			
325.1	Producing Lands	-	-	-
325.2	Producing Leaseholds	-	-	-
325.3	Gas Rights	-	-	-
325.4	Rights of Way	185,000	-	-
325.5	Other Land and Land Rights	-	-	-
326	Other Plant and Miscellaneous Equipment	-	-	-
327	Field Compressor Station Structures	1,235,000	-	-
328	Field Measuring & Regulating Station Structures	-	-	-
329	Other Structures	-	-	-
330	Producing Gas Wells-Well Construction	-	(598,329)	-
331	Producing Gas Wells-Well Equipment	-	(228,454)	-
332	Field Lines	3,697,000	(1,130,225)	1,656,000
333	Field Compressor Station Equipment	10,865,000	-	-
334	Field Measuring & Regulating Station Equipment	163,266	(1,607)	-
335	Drilling & Cleaning Equipment	-	-	-
336	Purification Equipment	-	-	-
337	Other Equipment	-	-	-
338	Unsuccessful Exploration & Development Costs	-	-	-
	Total Natural Gas Production & Gathering Plant	16,145,266	(1,958,615)	1,656,000
	TRANSMISSION PLANT			
365.1	Land and Land Rights	-	-	-
365.2	Rights of Way	-	-	-
366	Structures and Improvements	-	-	-
367	Mains	2,613,520	(353,553)	-
368	Compressor Station Equipment	2,238,242	(196,507)	-

FERC Acct	Description	*Additions* 1/1/2008 - 12/31/2008	*Retirements* 1/1/2008 - 12/31/2008	*Producing* 1/1/2009 - 6/30/2009
369	Measuring and Regulating Station Equipment	-	-	-
370	Communication Equipment	-	-	-
371	Other Equipment	-	-	-
	Total Transmission Plant	4,851,762	(550,060)	-
	DISTRIBUTION PLANT			
374	Land & Land Rights	-	-	-
375	Structures and Improvements	65,000	(137,434)	-
376	Mains	18,066,193	(872,361)	6,425,760
377	Compressor Station Equipment	-	-	-
378	Measuring & Regulating Station Equipment-General	742,011	(55,696)	617,753
	Measuring & Regulating Station Equipment-Odorization	-	-	-
379	Measuring & Regulating Station Equipment-City Gate C. St.	-	-	-
380	Services	4,604,174	(735,051)	1,690,000
381	Meters	1,220,189	(1,094,700)	636,394
382	Meter Installations	313,496	(503)	-
383	House Regulators	-	-	-
384	House Regulatory Installations	-	-	-
385	Industrial Measuring and Regulating Station Equipment	-	-	-
386	Other Property on Customers' Premises - Metscan Devices	-	(4,022,296)	-
386	Other Property on Customers' Premises - Metscan Installations	-	(2,227,024)	-
386	Other Property on Customers' Premises - Batteries	-	(337,621)	-
387	Other Equipment	-	-	-
387	Other Equipment - CNG Refueling Stations	-	(919,435)	-
388	Asset Retirement Costs for Distribution Plant	-	-	-
	Total Distribution Plant	25,011,063	(10,402,121)	9,369,907
	GENERAL PLANT			
389	Land & Land Rights	-	-	-
390	Structures and Improvements	-	-	-
390	Structures and Improvements - ACM	-	-	-
391	Office Furniture & Equipment - Computer Hardware	399,557	(5,579,644)	141,000
391	Office Furniture & Equipment - General Office Equip	-	(275,794)	-
392	Transportation Equipment - Autos and Trucks	2,170,949	(1,384,915)	741,782
392	Transportation Equipment - Trailers	-	-	-
393	Stores Equipment	-	(18,657)	-
394	Tools & Garage Equipment	490,896	(791,097)	242,451
395	Laboratory Equipment		(26,059)	
396	Power Operated Equipment	-	-	-

FERC Acct	Description	Additions 1/1/2008 - 12/31/2008	Retirements 1/1/2008 - 12/31/2008	Producing 1/1/2009 - 6/30/2009
397	Communication Equipment	-	-	-
397	Telephone	-	(991,124)	-
397	Radio	-	(409,927)	-
397	Microwave	-	(8,639)	-
397	Hardware	193,731	(1,558,614)	-
397	SCADA & Telemetering	-	(298,785)	-
397	Miscellaneous	-	(344,954)	-
397	Test Equipment	-	(25,292)	-
398	Miscellaneous Equipment	-	(86,779)	-
399	Other Tangible Property	-	-	-
	Total General Plant	3,255,133	(11,800,280)	1,125,233
	TOTAL PLANT IN SERVICE	$ 51,193,568	$ (30,085,971)	$ 13,151,140

Equitable Gas Company

DOCKET NO.: R-2008-2029325
MEASURE OF VALUE SCHEDULE
Test Year Ending December 31, 2008

		(A)	(B)	(C)	(D)
			Company Claim	OTS Adjustment	OTS
1	Plant In Service				
		Non Depreciable Plant	$741,784	$0	$741,784
		Depreciable Plant	$884,061,803	$0	$884,061,803
		Post Test Year Plant	$13,151,140	($13,151,140)	$0
2			$897,954,727	($13,151,140)	$884,803,587
3	Less: Accrued Depreciation		$289,353,072	$0	$289,353,072
4	Depreciated Plant In Service		$608,601,655	($13,151,140)	$595,450,515
5	Add:	Materials and Supplies	$887,426	$0	$887,426
6		Current Gas Storage	$75,175,769	($12,815,557)	$62,360,212
7		Cash Working Capital	$11,335,335	$0	$11,335,335
8		Prepayments	$234,270	$0	$234,270
9	Less:	Deferred Income Taxes	$104,709,261	$0	$104,709,261
		Defferred Income Taxes-Other	$0	$0	$0
		Deferred ITC	$4,902,910	$0	$4,902,910
10		Customer Deposits	$3,369,694	$164,315	$3,534,009
11		**Original Cost Measure of Value**	**$583,252,589**	**($26,131,011)**	**$557,121,578**

Equitable Gas Company

R-2008-2029325

DEPRECIATION AND AMORTIZATION EXPENSE

Test Year Ending December 31, 2008

	Depreciation and Amortization Expense:	Company Claim	OTS Adjustment	OTS
	(A)	(B)	(C)	(D)
1	Plant in Service	\$23,836,313	\$0	\$23,836,313
2	Post Test Year Plant Additions	\$639,933	(\$639,933)	\$0
3	Total Depreciation Expense	\$24,476,246	(\$639,933)	\$23,836,313
4	Amortization of Salvage	\$541,257	\$0	\$541,257
5	Total Depreciation and Amortization Expense	\$25,017,503	(\$639,933)	\$24,377,570

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Acct. #	GAS PLANT IN SERVICE Item	Company Original Cost 2007	2008 Additions	Company Original Cost 2008	OTS Adjustment	OTS Original Cost	Annual Accrual Rate	Company Accrued	OTS Adjustment	OTS Accrued	Company Annual	Amortization of Net Salvage	Company Depreciation Expense	OTS Adjustment	OTS Annual
		Intangible Plant														
1	303	Misc. Intangible Plant - Software	$10,210,955	($2,640,463)	$7,570,492	$0	$7,570,492	15.97	$3,676,768	$0	$3,676,768	$1,208,908	$0	$1,208,908	($0)	$1,208,907.87
2	303.1	Customer Information System	$14,695,007	$933,038	$15,628,045	$0	$15,628,045	6.59	$4,558,877	$0	$4,558,877	$1,030,156	$0	$1,030,158	$0	$1,030,158.00
3		Total Intangible Plant	$24,905,962	($1,707,425)	$23,198,537	$0	$23,198,537		$8,235,645	$0	$8,235,645	$2,239,066	$0	$2,239,066	($0)	$2,239,065.87
		Production & Gathering Plant														
4	325.2	Producing Leaseholds	$16,356	$0	$16,356	$0	$16,358	0.24	$15,550.00	$0	$15,550.00	$40	$0	$40	$0	$40.00
5	325.3	Gas Rights	$11,865	$0	$11,865	$0	$11,865	0.00	$11,665.00	$0	$11,665.00	$0	$0	$0	$0	$0.00
6	325.4	Rights-of-Way	$195,927	$185,000	$380,927	$0	$380,927	1.59	$193,665	$0	$193,665	$6,038	$0	$6,038	$0	$6,038.00
7	325.52	Other Land Rights	$1,551	$0	$1,551	$0	$1,551	0.71	$1,084	$0	$1,084	$11	$0	$11	$0	$11.00
8	327	Field Compressor Station Structures	$242,123	$1,235,000	$1,477,123	$0	$1,477,123	2.63	$208,925	$0	$208,925	$38,797	$0	$38,797	$0	$38,797.00
9	328	Field Meas. & Reg. Structures	$16,862	$0	$16,862	$0	$16,862	3.92	$10,388	$0	$10,388	$661	$0	$661	$0	$661.00
10	330	Producing Gas Well Construction	$598,329	($598,329)	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0.00
11	331	Producing Gas Well Equipment	$226,454	($226,454)	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0.00
12	332	Field Lines	$9,329,735	$2,566,775	$11,896,510	$0	$11,896,510	1.10	$6,351,473	$0	$6,351,473	$130,414	$0	$130,414	$0	$130,414.00
13	333	Field Compressor Station Equipment	$1,688,839	$10,865,000	$12,553,839	$0	$12,553,839	3.18	$1,199,014	$0	$1,199,014	$398,858	$0	$398,858	$0	$398,858.00
14	334	Field Meas. & Reg. Station Equipment	$258,892	$161,659	$420,551	$0	$420,551	3.55	$158,857	$0	$158,857	$14,939	$0	$14,939	$0	$14,939.00
15	337	Other Equipment	$3,066	$0	$3,066	$0	$3,066	0.72	$2,646	$0	$2,646	$22	$0	$22	$0	$22.00
16		*Total Production Plant*	*$12,591,999*	*$14,186,651*	*$26,778,650*	*$0*	$26,778,650		$8,153,467	$0	$8,153,467	$589,780	$0	$589,780	$0	$589,780
		Transmission Plant														
17	365.2	Rights of Way	$415,813.00	$0	$415,813.00	$0	$415,813.00	1.16	$188,150.00	$0	$188,150.00	$4,824.00	$0.00	$4,824	$0	$4,824.00
	366	Structures and Improvements														
18		Compressor Station	$1,021,208	$0	$1,021,208	$0	$1,021,208	2.42	$619,817	$0	$619,817	$24,738	$0	$24,738	$0	$24,738.00
19		Measuring & Regulating	$55,780	$0	$55,780	$0	$55,780	1.85	$46,553	$0	$46,553	$1,034	$0	$1,034	$0	$1,034.00
20		Total Account 366	$1,076,988	$0	$1,076,988	$0	$1,076,988		$666,370	$0	$666,370	$25,772	$0	$25,772	$0	$25,772.00
21	367	Mains	$13,153,374	$2,259,967	$15,413,341	$0	$15,413,341	1.31	$7,388,459	$0	$7,388,459	$202,460	$0	$202,460	$0	$202,460.00
22	368	Compressor Station Equipment	$11,394,604	$2,041,734	$13,436,338	$0	$13,436,338	3.16	$3,168,784	$0	$3,158,784	$424,251	$0	$424,251	$0	$424,251.00
23	369	Meas. & Reg. Station Equipment	$1,829,775	$0	$1,829,775	$0	$1,829,775	2.90	$1,085,108	$0	$1,085,108	$53,024	$0	$53,024	$0	$53,024.00
24	370	Communication Equipment	$137,223	$0	$137,223	$0	$137,223	1.35	$130,396	$0	$130,396	$1,854	$0	$1,854	$0	$1,854.00
25		Total Transmission Plant	$28,007,777	$4,301,701	$32,309,478	$0	$32,309,478		$12,627,267	$0	$12,627,267	$712,185	$0	$712,185	$0	$712,185.00

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Item	Company Original Cost 2007	2008 Additions	Company Original Cost 2008	OTS Adjustment	OTS Original Cost	Annual Accrual Rate	Company Accrued	OTS Adjustment	OTS Accrued	Company Annual	*Amortization of* Net Salvage	Company Depreciation Expense	OTS Adjustment	OTS Annual
		Distribution Plant														
1	374.2	Land Rights	$1,882,394	$0	$1,882,394	$0	$1,882,394	1.38	$635,275	$0	$635,275	$25,904	$0	$25,904	$0	$25,904.00
2	375	Structures and Improvements	$2,183,025	($72,434)	$2,110,591	$0	$2,110,591	2.30	$949,186	$0	$949,186	$48,530	$0	$48,530	$0	$48,530.00
	376	Mains														
3		Installations 1970 & Prior	$36,153,042	($201,560)	$35,951,482	$0	$35,951,482	0.58	$31,510,192	$0	$31,510,192	$206,758	$2,723	$209,481	$0	$206,758.00
4		*Installations 1971 & Later*	$408,223,240	$17,395,393	$425,618,633	$0	$425,618,633	1.58	$98,921,442	$0	$98,921,442	$6,643,918	$15,511	$6,659,429	$0	$6,643,918.00
5		Total Account 376	$444,376,282	$17,193,833	$461,570,115	$0	$461,570,115		$130,431,634	$0	$130,431,634	$6,850,676	$18,234	$6,868,910	$0	$6,850,676.00
	378	*Meas. & Reg Station Equipment*														
6		General	$16,290,894	$686,315	$16,977,209	$0	$16,977,209	2.27	$5,961,931	$0	$5,961,931	$385,157	$660	$385,817	$0	$385,157.00
7		Odorization	$446,577	$0	$446,577	$0	$446,577	2.49	$248,682	$0	$248,682	$11,107	$0	$11,107	$0	$11,107.00
8		Total Account 378	$16,737,471	$686,315	$17,423,786	$0	$17,423,786		$6,210,613	$0	$6,210,613	$396,264	$660	$396,924	$0	$396,264.00
9	380	Services	$220,873,047	$3,869,122	$224,742,169	$0	$224,742,169	2.25	$83,524,473	$0	$83,524,473	$5,065,693	$689,571	$5,755,264	$0	$5,065,693.00
10	381	Meters	$17,013,099	$125,488	$17,138,587	$0	$17,138,587	3.54	$7,883,532	$0	$7,883,532	$606,918	($20)	$606,898	$0	$606,918.00
11	382	Meter Insallations	$8,895,123	$312,994	$9,208,117	$0	$9,208,117	1.66	$5,091,875	$0	$5,091,875	$153,004	$0	$153,004	$0	$153,004.00
12	383	House Regulators	$5,656,348	$0	$5,656,348	$0	$5,656,348	1.64	$3,095,538	$0	$3,095,538	$92,904	$0	$92,904	$0	$92,904.00
13	384	House *Regulator Installations*	$1,513,982	$0	$1,513,982	$0	$1,513,982	1.67	$846,091	$0	$846,091	$25,315	$0	$25,315	$0	$25,315.00
14	385	Industrial Meas. & Reg. Station Equipment	$440,985	$0	$440,985	$0	$440,985	2.26	$266,766	$0	$266,766	$9,962	$0	$9,962	$0	$9,962.00
	386	Other *Property on Customer Premises*														
15		ERTs	$12,402,244	$0	$12,402,244	$0	$12,402,244	8.18	$1,544,104	$0	$1,544,104	$1,014,779	$0	$1,014,779	$0	$1,014,779.00
16		ERT Installations	$3,435,574	$0	$3,435,574	$0	$3,435,574	7.69	$607,113	$0	$607,113	$264,342	$0	$264,342	$0	$264,342.00
17		Metscan Devices	$6,586,942	($6,586,942)	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0.00
18		Total Account 386	$22,424,760	($6,586,942)	$15,837,818	$0	$15,837,818		$2,151,217	$0	$2,151,217	$1,279,121	$0	$1,279,121	$0	$1,279,121.00
	387	Other Equipment														
19		Natural Gas Fueling Stations	$1,069,132	($919,435)	$149,697	$0	$149,697	76.63	($303,223)	$0	($303,223)	$114,717	($9,717)	$105,000	$0	$114,717.00
20		Other Equipment	$174,220	$0	$174,220	$0	$174,220	1.18	$135,971	$0	$135,971	$2,059	($117)	$1,942	$0	$2,059.00
21		Total Account 387	$1,243,352	($919,435)	$323,917	$0	$323,917		($167,252)	$0	($167,252)	$116,776	($9,834)	$106,942	$0	$116,776.00
22		Total Distribution Plant	$743,239,868	$14,608,941	$757,848,809	$0	$757,848,809		$240,918,948	$0	$240,918,948	$14,671,067	$698,611	$15,369,678	$0	$14,671,067.00

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Item	Company Original Cost 2007	2008 Additions	Company Original Cost 2008	OTS Adjustment	OTS Original Cost	Annual Accrual Rate	Company Accrued	OTS Adjustment	OTS Accrued	Company Annual	Amortization of Net Salvage	Company Depreciation Expense	OTS Adjustment	OTS Annual
		General Plant														
1	389 2	Land Rights	$11,737	$0	$11,737	$0	$11,737	0.43	$10,138	$0	$10,138	$50			$0	$50.00
	390	Structures and Improvements														
2		Owned	$1,436,197	$0	$1,436,197	$0	$1,436,197	3.57	$62,584	$0	$62,584	$51,266	($2,021)	$49,245	$0	$51,266.00
3		Leased-Allegheny Center Mall	$2,733,671	$0	$2,733,671	$0	$2,733,671	12.26	$2,125,604	$0	$2,125,604	$335,175	$254	$335,429	$0	$335,175.00
4		Leased-North Shore	$3,739,252	$0	$3,739,252	$0	$3,739,252	5.82	$466,355	$0	$466,355	$217,476	$0	$217,476	$0	$217,476.00
5		Total Account 390	$7,909,120	$0	$7,909,120	$0	$7,909,120		$2,654,543	$0	$2,654,543	$603,917	($1,767)	$602,150	$0	$603,917.00
	391	Office Furniture and Equipment														
6		Furniture & Equipment	$3,734,403	($12,002)	$3,722,401	$0	$3,722,401	4.11	$1,309,668	$0	$1,309,668	$153,176	($194)	$152,982	$0	$153,176.00
7		Computer Hardware	$12,951,309	($4,588,204)	$8,363,105	$0	$8,363,105	34.33	$1,930,781	$0	$1,930,781	$2,870,938	($2,000)	$2,868,938	$0	$2,870,938.00
8		Total Account 391	$16,685,712	($4,600,206)	$12,085,506	$0	$12,085,506		$3,240,449	$0	$3,240,449	$3,024,114	($2,194)	$3,021,920	$0	$3,024,114.00
	392	Transportation Equipment														
9		Autos & Trucks	$8,672,250	$786,034	$9,458,284	$0	$9,458,284	13.83	$4,152,534	$0	$4,152,534	$1,308,284	($130,714)	$1,177,570	$0	$1,308,284.00
10		Trailers	$88,180	$0	$88,180	$0	$88,180	5.66	$29,473	$0	$29,473	$4,987	($782)	$4,205	$0	$4,987.00
11		Total Account 392	$8,760,430	$786,034	$9,546,464	$0	$9,546,464		$4,182,007	$0	$4,182,007	$1,313,271	($131,496)	$1,181,775	$0	$1,313,271.00
12	393	Stores Equipment	$64,862	($17,837)	$47,025	$0	$47,025	9.48	$3,081	$0	$3,081	$4,459	($314)	$4,145	$0	$4,459.00
13	394	Tools, Shop & Garage Equipment	$3,876,951	$177,886	$4,054,837	$0	$4,054,837	5.07	$1,196,232	$0	$1,196,232	$205,434	$4,715	$210,149	$0	$205,434.00
14	395	Laboratory Equipment	$26,059	($26,059)	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0.00
15	396	Power Operated Equipment	$3,155,085	$0	$3,155,085	$0	$3,155,085	8.72	$1,870,931	$0	$1,870,931	$275,049	($27,747)	$247,302	$0	$275,049.00
	397	Communication Equipment														
16		Telephone	$2,149,427	($415,741)	$1,733,686	$0	$1,733,686	6.75	$1,355,556	$0	$1,355,556	$116,995	$1,450	$118,445	$0	$116,995.00
17		Radio	$4,865,244	($409,927)	$4,455,317	$0	$4,455,317	0.07	$4,424,601	$0	$4,424,601	$3,172	$0	$3,172	$0	$3,172.00
18		Microwave	$207,298	($8,639)	$198,659	$0	$198,659	3.44	$120,895	$0	$120,895	$6,838	$0	$6,838	$0	$6,838.00
19		Hardware	$679,075	($465,495)	$213,580	$0	$213,580	8.38	$44,168	$0	$44,168	$17,901	$0	$17,901	$0	$17,901.00
20		Scada & Telemetering	$489,863	($298,785)	$191,078	$0	$191,078	0.61	$182,271	$0	$182,271	$1,175	$0	$1,175	$0	$1,175.00
21		Miscellaneous	$396,104	($344,954)	$51,150	$0	$51,150	45.84	$12,205	$0	$12,205	$23,447	$0	$23,447	$0	$23,447.00
22		Test Equipment	$110,367	($25,292)	$85,075	$0	$85,075	11.45	$58,659	$0	$58,659	$9,738	$0	$9,738	$0	$9,738.00
23		Total Account 397	$8,897,378	($1,968,833)	$6,928,545	$0	$6,928,545		$6,198,355	$0	$6,198,355	$179,266	$1,450	$180,716	$0	$179,266.00
24	398	Miscellaneous Equipment	$207,994	($19,984)	$188,010	$0	$188,010	9.92	$62,009	$0	$62,009	$18,655	$0	$18,655	$0	$18,655.00
25		Total General Plant	$49,595,328	($5,668,999)	$43,926,329	$0	$43,926,329		$19,417,745	$0	$19,417,745	$5,624,215.00	($157,353.00)	$5,466,862	$0	$5,624,215.00
		Property Fully Amortized														
26	303.02	Misc. Intangible Plant - Software	$1,737,126	($1,737,126)	$0	$0	$0									
27	391.02	Furniture and Equipment	$263,792	($263,792)	$0	$0	$0									
28	391.12	Computer Hardware	$591,884	($591,884)	$0	$0	$0									
29	393.02	Stores Equipment	$820	($820)	$0	$0	$0									
30	394.02	Tools, Shop & Garage Equipment	$478,087	($478,087)	$0	$0	$0									
31	397.12	Telephone	$575,383	($575,383)	$0	$0	$0									
32	397.42	Hardware	$899,388	($899,388)	$0	$0	$0									
33	398.02	Miscellaneous Equipment	$66,795	($66,795)	$0	$0	$0									
34		Total Property Fully Amortized	$4,613,275	($4,613,275)	$0	$0	$0									
35		Total Depreciable Plant	$862,954,209	$21,107,594	$864,061,803	$0	$864,061,803		$289,353,072	$0	$289,353,072	$23,836,313	$541,258	$24,377,571	($0.00)	$23,836,313
					$21,107,594											

OTS Exhibit No. 5
Schedule 9
page 3 of 4

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Item Nondepreciable Plant	Company Original Cost 2007	2008 Additions	Company Original Cost 2008	OTS Adjustment	OTS Original Cost	Annual Accrual Rate	Company Accrued	OTS Adjustment	OTS Accrued	Company Annual	Amortization of Net Salvage	Company Depreciation Expense	OTS Adjustment	OTS Annual
1	301	Organization	$49,770	$0	$49,770	$0	$49,770									
2	325.1	Producing Lands	$2,365	$0	$2,365	$0	$2,365									
3	325.51	Other Lands	$8,251	$0	$8,251	$0	$8,251									
4	365.1	Land	$40,447	$0	$40,447	$0	$40,447									
5	374.1	Land	$574,665	$0	$574,665	$0	$574,665									
6	389.1	Land	$66,285	$0	$66,285	$0	$66,285									
7		Total Nondepreciable Plant	$741,784	$0	$741,784	$0	$741,784									
		POST FUTURE TEST YEAR ADDITIONS														
8	303	Misc. Intangible Plant - Software			$1,000,000	($1,000,000)	$0	20.00				$200,000			($200,000)	$0
9	332	Field Lines			$1,656,000	($1,656,000)	$0	2.50				$41,400			($41,400)	$0
10	376	Mains			$6,425,760	($6,425,760)	$0	2.03				$130,446			($130,446)	$0
11	378	Meas. & Reg. Station Equipment			*$617,753*	*($617,753)*	$0	*2.77*				$17,112			($17,112)	$0
12	380	Services			$1,690,000	($1,690,000)	$0	3.52				$59,488			($59,488)	$0
13	381	Meters			$636,394	($636,394)	$0	5.69				$36,220			($36,220)	$0
14	391.1	Computer Hardware			$141,000	($141,000)	$0	20.00				$28,200			($28,200)	$0
15	392	Transportation Equipment			*$741,782*	*($741,782)*	$0	*15.82*				$117,371			($117,371)	$0
16	394	Tools, Shop & Garage Equipment			$242,451	($242,451)	$0	4.00				$9,698			($9,698)	$0
17		Total Post Future Test Year Additions	$0		$13,151,140	($13,151,140)	$0					$639,933			($639,933)	$0
18		TOTAL GAS PLANT	$883,695,993	$34,258,734	$897,954,727	($13,151,140)	$884,603,587					$24,476,246	$541,257	$25,017,503	($639,933)	$23,836,313

OTS Exhibit No. 5
Schedule 9
page 4 of 4

Docket No. R-2008-2029325
Item: OTS-RS-2-D
Respondent: Robert M. Narkevic
Position: Manager, Rates

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RS-2-D

Concerning the Company's weather normalization adjustment shown in Exhibit VI, Volume 1 of 3, provide the following:

A. Exact 20 year data that was used to calculate the normal HDD for each month, along with the specific location(s);

B. 30 years of data (HDD), from January 1987 through December 2007, gathered from the location(s) stated above.

Response:

A. Please see the attached for the 20 year data that was used to calculate the normal HDD for each month. The specific location is the Pittsburgh International Airport.

B. Please see the attached for the 30 years of data (HDD), from January 1978 through December 2007, gathered from the location stated above.

OTS Exhibit No. 5
Schedule 10
page 2 of 2

EQUITABLE GAS COMPANY
Docket No. R-2008-2029325
OTS RS-2

Subject: Historical Degree Days

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
January	1,307	1,346	1,175	1,372	1,361	1,080	1,293	1,322	1,131	1,139
February	1,229	1,309	1,177	936	1,017	904	823	1,038	936	904
March	860	671	906	904	819	746	1,008	701	737	710
April	412	458	500	391	586	535	471	334	368	451
May	209	219	172	223	82	280	305	163	148	145
June	38	38	71	18	67	44	16	65	37	22
July	4	23	0	3	9	10	12	3	1	4
August	3	26	5	10	23	2	7	9	40	20
September	80	111	48	159	119	126	165	116	65	61
October	485	438	476	475	336	365	214	300	346	529
November	656	601	787	736	605	639	734	531	733	560
December	993	935	1,117	1,098	770	1,223	790	1,160	983	920
Totals	6,276	6,175	6,434	6,325	5,794	5,954	5,838	5,742	5,525	5,465

Month	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
January	1,181	905	869	1,085	1,063	920	1,357	1,047	1,155	1,136
February	1,040	1,033	781	820	880	1,037	988	1,071	1,005	832
March	792	739	657	674	805	841	836	678	930	755
April	461	532	439	337	417	445	345	487	436	554
May	149	260	229	63	210	135	278	163	215	330
June	64	25	49	5	50	43	21	5	5	35
July	5	1	4	0	1	0	0	0	14	2
August	3	14	1	0	17	0	10	0	1	21
September	83	102	116	127	116	118	80	79	104	109
October	570	364	314	308	457	407	351	269	397	401
November	619	723	577	698	657	654	516	799	853	771
December	1,018	1,414	829	913	956	1,028	824	1,150	873	973
Totals	5,985	6,112	4,865	5,030	5,629	5,628	5,606	5,748	5,988	5,919

Month	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
January	858	1,075	1,148	1,123	910	1,343	1,319	1,087	825	1,000
February	736	861	833	833	834	1,073	959	907	962	1,229
March	716	917	620	912	739	737	684	916	824	666
April	415	387	442	350	399	348	417	376	326	521
May	78	140	135	171	275	186	94	272	228	104
June	75	40	33	43	15	58	30	15	43	21
July	0	1	8	17	0	0	4	0	3	3
August	0	6	14	2	0	0	24	2	0	7
September	52	101	158	125	38	96	44	27	127	61
October	369	386	317	341	455	442	359	368	432	222
November	616	541	761	497	736	560	565	623	586	689
December	837	935	1,291	846	1,055	997	975	1,153	805	938
Totals	4,752	5,390	5,760	5,260	5,456	5,840	5,474	5,746	5,161	5,461

Equitable Gas Company
Docket No. R-2008-2042293
Summary of Increases to Present Rate Revenues Per OTS

	Customer Class	Company Claim	OTS Proposed Adjustment	Adjusted Revenue Per OTS
	(A)	(B)	(C)	(D)
	Tariff Sales Service			
	RS - Residential Service			
1	Non - Gas Revenues	$93,383,154	$1,834,175	$95,217,330
2	Gas Costs	$256,000,857	$7,300,117	$263,300,974
3	STAS	($314,446)	$0	($314,446)
4	Total RS Present Rate Revenue	$349,069,565	$9,134,291	$358,203,857
	GSS - General Service Small			
5	Non - Gas Revenues	$11,042,157	$143,984	$11,186,141
6	Gas Costs	$38,927,009	$691,936	$39,618,945
7	STAS	($44,972)	$0	($44,972)
8	Total GSS Present Rate Revenue	$49,924,194	$835,921	$50,760,114
	GSL - General Service Large			
9	Non - Gas Revenues	$4,564,328	$64,404	$4,628,732
10	Gas Costs	$20,054,053	$332,001	$20,386,054
11	STAS	($22,157)	$0	($22,157)
12	Total GSL Present Rate Revenue	$24,596,223	$396,405	$24,992,628
	GL - Gas Lights			
13	Non - Gas Revenues	$8,229	$0	$8,229
14	Gas Costs	$39,362	$0	$39,362
15	STAS	$0	$0	$0
16	Total GL Present Rate Revenue	$47,592	$0	$47,592
17	**Total Tariff Sales Service**	$423,637,575	$10,366,617	$434,004,192
18	**Purchased Gas Cost (line 2+6+10+14)**	$315,021,281	$8,324,054	$323,345,335

Equitable Gas Company
Docket No. R-2008-2029325

OTS Proposed Residential Present Rate Revenues and Cost of Gas
Test Year Ending December 31, 2008

				Per Company			Per OTS			
	Rate RS - Residential Service (A)	No. of Bills (B)	Present Rates (C)	Total Normal Usage (Mcf) (D)	Annualized and Normalized Volumes (Mcf) (E)	Present Revenue (F)	Total Normal Usage (Mcf) (G)	Annualized and Normalized Volumes (Mcf) (H)=(G)*(B)	Present Revenue (I)	Increase to Present Rate Revenues (J)
1		206,044 Customers		88.94	18,325,043		91.47	18,847,600		
2	Monthly Service Charge	2,494,614 (206,044 customers)	**$11.65**			$29,062,253			$29,062,253	$0
	Commodity Charge:									
3	Delivery Charge		$2.703		18,325,043	$49,532,591		18,847,600	$50,945,063	$1,412,472
4	Rider C - Transporation Cost		$0.227		18,325,043	$4,159,785		18,847,600	$4,278,405	$118,620
5	*Subtotal*		*$2.930*			$53,692,376			$55,223,468	$1,531,092
6	Rider D - Universal Service		$0.580		18,325,043	$10,628,525		18,847,600	$10,931,608	$303,083
7	Total Commodity (non-gas)		**$3.510**		18,325,043	$64,320,901		18,847,600	$66,155,076	$1,834,175
8	Subtotal Non-Gas (Line 2 + Line 7)					$93,383,154			$95,217,330	**$1,834,175**
9	Rider A - Natural Gas Supply		$13.970		18,325,043	$256,000,857		18,847,600	$263,300,974	
10	Subtotal Gas Supply					$256,000,857			$263,300,974	**$7,300,117**
11	STAS					($314,446)			($314,446)	
12	Total Rate RS					**$349,069,566**			**$358,203,857**	**$9,134,291**

(B), (C), (E), (F) Reference Equitable St. No. 1, Attachment JMQ-3, Sheet 1

(G) Reference OTS Exhbit No. 5, Schedule 15

OTS Exhibit No. 5
Schedule 12

Equitable Gas Company
Docket No. R-2008-2029325

OTS Proposed General Service Small (GSS) Present Rate Revenues and Cost of Gas
Test Year Ending December 31, 2008

	Rate GSS - General Service Small (A)	No. of Bills (B)	Present Rates (C)	Per Company: Total Normal Usage (Mcf) (D)	Per Company: Annualized and Normalized Volumes (Mcf) (E)	Per Company: Present Revenue (F)	Per OTS: Total Normal Usage (Mcf) (G)	Per OTS: Annualized and Normalized Volumes (Mcf) (H)=(G)*(B)	Per OTS: Present Revenue (I)	Increase to Present Rate Revenues (J)
1		13,556 Customers		205.55	2,786,472		209.20	2,836,002		
2	Monthly Service Charge	153,228	**$17.00**			$2,604,876			$2,604,876	$0
3		12,036	***$28.00***			*$337,008*			*$337,008*	*$0*
	Commodity Charge:									
4	Delivery Charge		$2.737		2,786,472	$7,626,574		2,836,002	$7,762,137	$135,563
5	Rider C - Transporation Cost		$0.170		2,786,472	$473,700		2,836,002	$482,120	$8,420
6	Total Commodity (non-gas)		$2.907			$8,100,274			$8,244,257	$143,984
7	Subtotal Non-Gas (Line 2 + Line 3 + Line 6)					$11,042,157			$11,186,141	**$143,984**
8	Rider A - Natural Gas Supply		$13.970		2,786,472	$38,927,009		2,836,002	$39,618,945	
9	Subtotal Gas Supply					$38,927,009			$39,618,945	**$691,936**
10	STAS					($44,972)			($44,972)	
11	Total Rate RS					**$49,924,194**			**$50,760,114**	**$835,921**

(B), (C), (E), (F) Reference Equitable St. No. 1, Attachment JMQ-3, Sheet 3

(G) Reference OTS Exhbit No. 5, Schedule 16

Equitable Gas Company
Docket No. R-2008-2029325

OTS Proposed General Service Large (GSL) Present Rate Revenues and Cost of Gas
Test Year Ending December 31, 2008

	Rate GSL - General Service Large (A)	No. of Bills (B)	Present Rates (C)	Per Company: Total Normal Usage (Mcf) (D)	Per Company: Annualized and Normalized Volumes (Mcf) (E)	Per Company: Present Revenue (F)	Per OTS: Total Normal Usage (Mcf) (G)	Per OTS: Annualized and Normalized Volumes (Mcf) (H)=(G)*(B)	Per OTS: Present Revenue (I)	Increase to Present Rate Revenues (J)
1		675 Customers		2,126.94	1,435,508		2,162.15	1,459,274		
2	Monthly Service Charge	7,716	**$75.00**			$578,700			$578,700	$0
3		444	**$150.00**			$66,600			$66,600	$0
4		36	**$800.00**			$28,800			$28,800	$0
	Commodity Charge:									
5	Delivery Charge		$2.540		1,435,508	$3,646,191		1,459,274	$3,706,555	$60,364
6	Rider C - Transporation Cost		$0.170		1,435,508	$244,036		1,459,274	$248,077	$4,040
7	Total Commodity (non-gas)		$2.710			$3,890,228			$3,954,632	$64,404
8	Subtotal Non-Gas (Line 2 + Line 3 + Line 4 + Line 7)					$4,564,328			$4,628,732	$64,404
9	Rider A - Natural Gas Supply		$13.970		1,435,508	$20,054,047		1,459,274	$20,386,054	
10	Subtotal Gas Supply					$20,054,053			$20,386,054	$332,001
11	STAS					($22,157)			($22,157)	
12	Total Rate RS					**$24,596,223**			**$24,992,628**	**$396,405**

(B), (C), (E), (F) Reference Equitable St. No. 1, Attachment JMQ-3, Sheet 4

(G) Reference OTS Exhbit No. 5, Schedule 17

Equitable Gas Company Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2008

	Customers	Baseload	Heat Factor	Normal HDD	Normalized Heat	Adjusted	1% conservation	Normalized Total
Residential Sales								
Jan-08	206,543	330,422	0.01392	1070	3,077,914	3,408,336	(30,779)	3,377,557
Feb-08	207,514	331,976	0.01470	936	2,855,186	3,187,162	(28,552)	3,158,610
Mar-08	207,675	332,233	0.01309	772	2,099,023	2,431,256	(20,990)	2,410,266
Apr-08	205,999	329,552	0.01335	422	1,159,402	1,488,954	(11,594)	1,477,360
May-08	205,257	328,365	0.00785	186	299,141	627,506	(2,991)	624,514
Jun-08	204,563	304,872	0.00000	34	-	304,872	-	304,872
Jul-08	204,027	327,016	0.00000	3	-	327,016	-	327,016
Aug-08	204,126	325,937	0.00000	6	-	325,937	-	325,937
Sep-08	204,250	326,754	0.00491	93	93,377	420,131	(934)	419,198
Oct-08	205,418	328,623	0.00843	376	652,248	980,871	(6,522)	974,349
Nov-08	207,935	332,649	0.01163	652	1,577,468	1,910,118	(15,775)	1,894,343
Dec-08	209,226	334,715	0.01314	991	2,723,542	3,058,257	(27,235)	3,031,021
	206,044	3,933,115		5,541	14,537,301	18,470,416	(145,373)	18,325,043
CAP								
Jan-08	18,976	32,066	0.02006	1070	407,370	439,436		
Feb-08	18,976	32,066	0.02167	936	384,733	416,799		
Mar-08	18,976	32,066	0.02367	772	346,740	378,806		
Apr-08	18,976	32,066	0.02221	422	177,703	209,770		
May-08	18,976	32,066	0.02999	186	105,693	137,759		
Jun-08	18,976	32,066	0.03724	34	23,847	55,913		
Jul-08	18,976	39,354	0.00000	3	-	39,354		
Aug-08	18,976	38,154	0.00000	6	-	38,154		
Sep-08	18,976	43,900	0.00000	93	-	43,900		
Oct-08	18,976	32,066	0.01260	376	89,981	122,047		
Nov-08	18,976	32,066	0.01578	652	195,291	227,357		
Dec-08	18,976	32,066	0.02057	991	386,689	418,755		
	18,976	410,005		5,541	2,118,047	2,528,051		

Equitable Gas Company Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2007

Rate GSS	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	13,569	370,422	57,266	313,155	1,000	1,070	335,170	392,436
Feb-07	13,586	635,436	57,338	578,098	1,229	936	440,135	497,473
Mar-07	13,589	491,083	57,351	433,732	666	772	502,699	560,050
Apr-07	13,614	276,182	57,456	218,725	521	422	177,037	234,494
May-07	13,516	136,473	57,043	79,431	104	186	141,867	198,910
Jun-07	13,470	66,788	56,849	9,940	21	34	15,975	72,823
Jul-07	13,470	58,313	58,313	-	3	3	-	58,313
Aug-07	13,446	55,283	55,283	-	7	6	-	55,283
Sep-07	13,482	58,543	56,899	1,643	61	93	2,509	59,409
Oct-07	13,531	65,762	57,106	8,656	222	376	14,678	71,784
Nov-07	13,688	153,303	57,769	95,534	689	652	90,411	148,179
Dec-07	13,714	417,206	57,878	359,327	938	991	379,439	437,317
	162,675	2,784,792	686,551	2,098,241	5461	5541		2,786,472

Baseload Factor 0.136141

Rate GSL	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	819	190,928	42,925	148,003	1,000	1,070	158,408	201,333
Feb-07	816	314,660	42,768	271,893	1,229	936	207,006	249,773
Mar-07	772	237,776	40,462	197,314	666	772	228,689	269,150
Apr-07	639	140,707	33,491	107,217	521	422	86,782	120,272
May-07	631	68,561	33,072	35,489	104	186	63,386	96,457
Jun-07	633	42,522	33,176	9,345	21	34	15,019	48,195
Jul-07	631	34,760	34,760	-	3	3	-	34,760
Aug-07	624	31,016	31,016	-	7	6	-	31,016
Sep-07	623	33,150	32,652	498	61	93	760	33,412
Oct-07	623	35,428	32,652	2,776	222	376	4,708	37,360
Nov-07	626	101,111	32,809	68,302	689	652	64,639	97,448
Dec-07	662	206,703	34,696	172,007	938	991	181,634	216,330
	8,099	1,437,322	424,479	1,012,843	5461	5541		1,435,508

Baseload Factor 1.690687

OTS Exhibit No. 5
Schedule 14

Equitable Gas Company
OTS Weather Normalization Calculation
Residential Sales
01/01/07 - 12/31/07

	Months	No. of Customers	Actual Sales (Mcf)	Base Load (Mcf)	Temperature Sensitive Load of Customers (Mcf)	Actual Deg. Days	Temperature Sensitive Load (Mcf / DD)	(NOAA) Normal Deg. Days (30 Year Ave.)	Normalized Temperature Sensitive Load (Mcf * DD)	Normalized Load (Mcf)
	A	B	C	D=B*Bload	E=C-D	F	G=E/F	H	I=G*H	J=D+I
1	Jan-07	211,137	3,277,484	337,772	2,939,712	1,000	2,940	1131	3,324,815	3,662,586
2	Feb	211,694	4,164,362	338,663	3,825,699	1,229	3,113	966	3,007,018	3,345,681
3	March	211,076	2,178,383	337,674	1,840,709	666	2,764	783	2,164,077	2,501,751
4	April	209,219	1,789,506	334,703	1,454,803	521	2,792	431	1,203,493	1,538,196
5	May	208,513	503,717	333,574	170,143	104	1,636	189	309,203	642,776
6	June	208,057	310,079	332,844	0	21	0	36	0	332,844
7	July	207,723	332,940	332,310	0	3	0	4	0	332,310
8	Aug	207,880	331,931	332,561	0	7	0	9	0	332,561
9	Sept	208,182	395,370	333,044	62,326	61	1,022	97	99,108	432,152
10	Oct	209,130	726,156	334,561	391,595	222	1,764	383	675,590	1,010,151
11	Nov	211,012	2,029,097	337,572	1,691,525	689	2,455	654	1,605,599	1,943,170
12	Dec-07	211,710	2,948,494	338,688	2,609,806	938	2,782	993	2,762,833	3,101,521
13	Total	2,515,333	18,987,519	4,023,965	14,986,319	5,461		5,676	15,151,736	19,175,701

14 Ave. No. of Customers 209,611

15 *NOAA Weather Station: Pittsburgh International Airport*

Degree Day Variance (Warmer)/Colder

16 **Average Use per Customer** 7.62 Mcf per month 91.48 Mcf per Year

		Customers	Mcf Sales
17	July	207,723	332,940
18	Aug	207,880	331,931
19	Total	415,603	664,871

20 **Base Load (Mcf) Per Customer (BL)** 1.60 Mcf per month

Equitable Gas Company
OTS Weather Normalization Calculation
Residential Sales
01/01/08 - 12/31/08

	Months	No. of Customers	Base Load (Mcf)	Heat Factor	(NOAA) Normal Deg. Days (30 Year Ave.)	Normalized Temperature Sensitive Load (Mcf * DD)	Adjusted	1% Conservation	Normalized Load (Mcf)
	A	B	C=B*Bload(2007)	D=I(2007)/B(2007)/E	E	F=B*D*E	G=C+F	H	I=G+H
1	**Jan-08**	206,543	330,422	0.01392	1131	3,252,472	3,582,894	0	3,582,894
2	**Feb**	207,514	331,976	0.01470	966	2,947,643	3,279,619	0	3,279,619
3	**March**	207,675	332,233	0.01309	783	2,129,208	2,461,441	0	2,461,441
4	**April**	205,999	329,552	0.01335	431	1,184,971	1,514,523	0	1,514,523
5	**May**	205,257	328,365	0.00785	189	304,374	632,739	0	632,739
6	**June**	204,563	327,255	0.00000	36	0	327,255	0	327,255
7	**July**	204,027	326,397	0.00000	4	0	326,397	0	326,397
8	**Aug**	204,126	326,556	0.00000	9	0	326,556	0	326,556
9	**Sept**	204,250	326,754	0.00491	97	97,236	423,990	0	423,990
10	**Oct**	205,418	328,622	0.00843	383	663,598	992,221	0	992,221
11	**Nov**	207,935	332,649	0.01163	654	1,582,186	1,914,835	0	1,914,835
12	**Dec-08**	209,226	334,714	0.01314	993	2,730,416	3,065,131	0	3,065,131
13	**Total**	2,472,533	3,955,495		5,678	14,892,105	18,847,600	0	18,847,600

14 **Ave. No. of Customers** 206,044

15 ***NOAA Weather Station: Pittsburgh International Airport***

Degree Day Variance (Warmer)/Colder

16 **Average Use per Customer** 7.62 Mcf per month 91.47 Mcf per Year

OTS Exhibit No. 5
Schedule 15

OTS Exhibit No. 5
Schedule 16

Equitable Gas Company
OTS Weather Normalization Calculation
General Service Small (GSS) Sales
01/01/07 - 12/31/07

	Months	No. of Customers	Actual Sales (Mcf)	Base Load (Mcf)	Temperature Sensitive Load of Customers (Mcf)	Actual Deg. Days	Temperature Sensitive Load (Mcf / DD)	(NOAA) Normal Deg. Days (30 Year Ave.)	Normalized Temperature Sensitive Load (Mcf * DD)	Normalized Load (Mcf)
	A	B	C	D=B*Bload	E=C-D	F	G=E/F	H	I=G*H	J=D+I
1	Jan-07	13,569	370,422	57,266	313,156	1,000	313	1131	354,179	411,445
2	Feb	13,586	635,436	57,338	578,098	1,229	470	966	454,388	511,726
3	March	13,589	491,083	57,351	433,732	666	651	783	509,928	567,279
4	April	13,614	276,182	57,456	. 218,726	521	420	431	180,942	238,398
5	May	13,516	136,473	57,043	79,430	104	764	189	144,349	201,392
6	June	13,470	66,788	56,849	9,939	21	473	36	17,039	73,888
7	July	13,470	58,313	56,849	0	3	0	4	0	56,849
8	Aug	13,446	55,283	56,747	0	7	0	9	0	56,747
9	Sept	13,482	58,543	56,899	1,644	61	27	97	2,614	59,513
10	Oct	13,531	65,762	57,106	8,656	222	39	383	14,933	72,039
11	Nov	13,688	153,303	57,769	95,534	689	139	654	90,681	148,450
12	Dec-07	13,714	417,206	57,878	359,328	938	383	993	380,397	438,275
13	Total	162,675	2,784,794	686,552	2,098,242	5,461		5,678	2,149,450	2,836,002

Ave. No.
14 **of Customers** 13,556

15 **NOAA Weather Station: Pittsburgh International Airport**

Degree Day Variance (Warmer)/Colder

16 **Average Use per Customer** 17.43 Mcf per month 209.20 Mcf per Year

		Customers	Mcf Sales
17	July	13,470	58,313
18	Aug	13,446	55,283
19	Total	26,916	113,596

20 **Base Load (Mcf) Per Customer (BL)** 4.22 Mcf per month

Equitable Gas Company
OTS Weather Normalization Calculation
General Service Large (GSL) Sales
01/01/07 - 12/31/07

	Months	No. of Customers	Actual Sales (Mcf)	Base Load (Mcf)	Temperature Sensitive Load of Customers (Mcf)	Actual Deg. Days	Temperature Sensitive Load (Mcf / DD)	(NOAA) Normal Deg. Days (30 Year Ave.)	Normalized Temperature Sensitive Load (Mcf * DD)	Normalized Load (Mcf)
	A	B	C	D=B*Bload	E=C-D	F	G=E/F	H	I=G*H	J=D+I
1	Jan-07	819	190,928	42,925	148,003	1,000	148	1131	167,392	210,316
2	Feb	816	314,660	42,768	271,892	1,229	221	966	213,709	256,476
3	March	772	237,776	40,461	197,315	666	296	783	231,978	272,439
4	April	639	140,707	33,491	107,216	521	206	431	88,695	122,186
5	May	631	68,561	33,071	35,490	104	341	189	64,495	97,567
6	June	633	42,522	33,176	9,346	21	445	36	16,021	49,198
7	July	631	34,760	33,071	0	3	0	4	0	33,071
8	Aug	624	31,016	32,705	0	7	0	9	0	32,705
9	Sept	623	33,150	32,652	498	61	8	97	792	33,444
10	Oct	623	35,428	32,652	2,776	222	13	383	4,789	37,441
11	Nov	626	101,111	32,809	68,302	689	99	654	64,832	97,641
12	Dec-07	662	206,703	34,696	172,007	938	183	993	182,093	216,789
13	Total	8,099	1,437,322	424,478	1,012,844	5,461		5,678	1,034,796	1,459,274

14 **Ave. No. of Customers** 675

15 **NOAA Weather Station: Pittsburgh International Airport**

Degree Day Variance (Warmer)/Colder

16 **Average Use per Customer** 180.18 Mcf per month 2162.15 Mcf per Year

		Customers	Mcf Sales
17	July	631	34,760
18	Aug	624	31,016
19	Total	1,255	65,776

20 **Base Load (Mcf) Per Customer (BL)** 52.41 Mcf per month

OTS Exhibit No. 5
Schedule 17

Docket No. R-2008-2029325
Item: OTS-RS-7-D
Respondent: Robert M. Narkevic
Position: Manager, Rates

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RS-7-D

Reference Company Exhibit VI, Volume 1 of 3, Item 6, Weather Normalization for TME 12/31/2008 for Residential Sales: Provide a spreadsheet which shows how the amounts were determined for the 1% Conservation Adjustment and explain what these amounts represent.

Response:

Please see the attached spreadsheet showing how the amounts were determined for the 1% Conservation Adjustment. These amounts represent an estimated reduction to normalized heating sales expected in 2008 due to high natural gas prices and increased conservation efforts.

EQUITABLE GAS COMPANY
Docket No. R-2008-2029325
OTS RS-7

	Customers	Baseload	Heat Factor	Normal HDD	Normalized Heat	Percentage	1% conservation
	(a)	(b)	(c)	(d)	(e)	(f)	(g) (e x f)
Residential Sales							
Jan-08	206,543	330,422	0.01392	1070	**3,077,914**	**-1%**	**(30,779)**
Feb-08	207,514	331,976	0.01470	936	**2,855,186**	**-1%**	**(28,552)**
Mar-08	207,675	332,233	0.01309	772	**2,099,023**	**-1%**	**(20,990)**
Apr-08	205,999	329,552	0.01335	422	**1,159,402**	**-1%**	**(11,594)**
May-08	205,257	328,365	0.00785	186	**299,141**	**-1%**	**(2,991)**
Jun-08	204,563	304,872	0.00000	34	-		-
Jul-08	204,027	327,016	0.00000	3	-		-
Aug-08	204,126	325,937	0.00000	6	-		-
Sep-08	204,250	326,754	0.00491	93	**93,377**	**-1%**	**(934)**
Oct-08	205,418	328,623	0.00843	376	**652,248**	**-1%**	**(6,522)**
Nov-08	207,935	332,649	0.01163	652	**1,577,468**	**-1%**	**(15,775)**
Dec-08	209,226	334,715	0.01314	990.5	**2,723,542**	**-1%**	**(27,235)**
Total	206,044	3,933,115		5,541	14,537,301		**(145,373)**

Equitable Gas Company

Docket No. R-2008-2029325

Cost of Service Study - Future Test Year Ended 12/31/2008

Customer Costs (Peak and Average Method)

Company (In $1000's)

Cost of Service Study - Future Test Year Ended 12/31/2008

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs - Summary				
1	Rate Base - Distribution	$118,374	$111,782	$1,296	$5,296
2	Rate Base - OnSite Function	$42,514	$35,026	$3,108	$4,380
3		$160,888	$146,808	$4,404	$9,676
4	Rate of Return				
5	Return on rate base	$14,303	$13,051	$392	$860
6	Income Tax gross-up	$7,042	$6,426	$192	$424
7	Operating expenses - Distribution	$15,800	$13,457	$1,581	$762
8	Operating expenses - OnSite	$54,869	$48,456	$2,905	$3,508
9	Depreciation expense - Distribution	$7,109	$6,686	$91	$332
10	Depreciation expense - OnSite	$4,061	$3,422	$292	$347
11	Additional expense	$1,103	$1,103	$0	$0
12		$104,287	$92,601	$5,453	$6,233
	Other Revenue				
13	Forfeited Discounts	$0	$0	$0	$0
14	Miscellaneous Service Rev.	$0	$0	$0	$0
15	Other Operating Revenue	$0	$0	$0	$0
16	Total Other Revenue	$0	$0	$0	$0
17	*Total Customer Component*	*$104,287*	*$92,601*	*$5,453*	*$6,233*
18	Average Bills X 1000	3,084	2,871	191	22
19	Average Monthly Cost	$33.82	$32.25	$28.55	$283.32

OTS (In $1000's)

Cost of Service Study - Future Test Year Ended 12/31/2008

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs - Summary				
1	Rate Base - Distribution	$114,986	$108,539	$1,127	$5,320
2	Rate Base - OnSite Function	$14,008	$9,728	$1,435	$2,845
3		$128,994	$118,267	$2,562	$8,165
4	Rate of Return				
5	Return on rate base	$11,468	$10,514	$228	$726
6	Income Tax gross-up	$5,647	$5,177	$112	$358
7	Operating expenses - Distribution	$2,972	$2,686	$197	$89
8	Operating expenses - OnSite	$46,098	$41,328	$2,178	$2,592
9	*Depreciation expense - Distribution*	*$5,815*	*$5,489*	*$57*	*$269*
10	Depreciation expense - OnSite	$797	$553	$82	$162
11	Additional expense	$0	$0	$0	$0
12		$72,797	$65,747	$2,854	$4,196
	Other Revenue				
13	Forfeited Discounts	($1,558)	($1,462)	($34)	($62)
14	Miscellaneous Service Rev.	($1,208)	($1,163)	($40)	($5)
15	Other Operating Revenue	($61)	($43)	($6)	($12)
16	Total Other Revenue	($2,827)	($2,668)	($80)	($79)
17	*Total Customer Component*	*$69,970*	*$63,079*	*$2,774*	*$4,117*
18	Average Bills X 1000	3,084	2,871	191	22
19	Average Monthly Cost	$22.69	$21.97	$14.52	$187.14

OTS Exhibit No. 5
Schedule 19
page 1 of 5

Company
(in $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Distribution Function				
20	Mains - Cost	$0	$0	$0	$0
21	Mains - Acc Depr	$0	$0	$0	$0
22	Mains - ADIT	$0	$0	$0	$0
23		$0	$0	$0 #	$0
24	Services - Cost	$226,432	$213,758	$2,209	$10,465
25	Services - Acc Depr	($83,524)	($78,849)	($815)	($3,860)
26	Services - ADIT	($27,922)	($26,370)	($267)	($1,285)
27		$114,986	$108,539	$1,127	$5,320
28	Other Rate Base	$3,388	$3,243	$169	($24)
29	Total Rate Base	$118,374	$111,782	$1,296	$5,296
	Mains				
30	*Return on Rate Base*	$0	$0	$0	$0
31	Income Tax gross-up	$0	$0	$0	$0
32	Maintenance of Mains	$0	$0	$0	$0
33	Mains & Services expense	$0	$0	$0	$0
34	Mains Depreciation exp	$0	$0	$0	$0
35		$0	$0	$0	$0
	Services				
36	Return on Rate Base	$10,222	$9,649	$100	$473
37	Income Tax gross-up	$5,033	$4,751	$49	$233
38	Maintenance of Services	$0	$0	$0	$0
39	Mains & Services expense	$1,617	$1,526	$16	$75
40	Services Depreciation exp	$5,815	$5,489	$57	$269
41		$22,687	$21,415	$222	$1,050

OTS
(in $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Distribution Function				
20	Mains - Cost	$0	$0	$0	$0
21	Mains - Acc Depr	$0	$0	$0	$0
22	Mains - ADIT	$0	$0	$0	$0
23		$0	$0	$0 #	$0
24	Services - Cost	$226,432	$213,758	$2,209	$10,465
25	Services - Acc Depr	($83,524)	($78,849)	($815)	($3,860)
26	Services - ADIT	($27,922)	($26,370)	($267)	($1,285)
27		$114,986	$108,539	$1,127	$5,320
28	Other Rate Base	$0	$0	$0	$0
29	Total Rate Base	$114,986	$108,539	$1,127	$5,320
	Mains				
30	*Return on Rate Base*	$0	$0	$0	$0
31	Income Tax gross-up	$0	$0	$0	$0
32	Maintenance of Mains	$0	$0	$0	$0
33	Mains & Services expense	$0	$0	$0	$0
34	Mains Depreciation exp	$0	$0	$0	$0
35		$0	$0	$0	$0
	Services				
36	Return on Rate Base	$10,222	$9,649	$100	$473
37	Income Tax gross-up	$5,033	$4,751	$49	$233
38	Maintenance of Services	$0	$0	$0	$0
39	*Mains & Services expense*	$0	$0	$0	$0
40	Services Depreciation exp	$5,815	$5,489	$57	$269
41		$21,070	$19,889	$206	$975

Line		Company (In $1000's) Total	Company Residential Service (RS)	Company General Service - Small (GSS)	Company General Service - Large (GSL)	OTS (In $1000's) Total	OTS Residential Service (RS)	OTS General Service - Small (GSS)	OTS General Service - Large (GSL)
	Balance of Distribution								
42	Return on Rate Base	$301	$288	$15	($2)	$0	$0	$0	$0
43	Income Tax gross-up	$148	$142	$7	($1)	$0	$0	$0	$0
44	Uncollectible Accounts	$0	$0	$0	$0	$0	$0	$0	$0
45	**Operating & Maintenance**								
	O & M Expenses - Distribution Expenses								
46	Operation Supv & Engineering	$526	$497	$5	$24	$0	$0	$0	$0
47	Other Expenses - Safety & Environmental	$65	$60	$2	$3	$0	$0	$0	$0
48	Other Expenses	$67	$62	$2	$3	$0	$0	$0	$0
49	Distribution Rents	$179	$169	$2	$8	$0	$0	$0	$0
50	Maint. Supervision & Engineering	$152	$107	$37	$8	$152	$107	$37	$8
51	Maint. Of Stuctures & Improvements	$165	$155	$2	$8	$0	$0	$0	$0
52	Maintenance of Other Equipment	$21	$20	$0	$1	$0	$0	$0	$0
	Customer Services & Informational Exp.								
53	Customer Assist. - Other	$510	$474	$32	$4	$510	$474	$32	$4
54	Other Cust. Service & Informational Exp.	$698	$698	$0	$0	$698	$698	$0	$0
55	Demonstration	$659	$0	$591	$68	$0	$0	$0	$0
56	Advertising Expense	$25	$0	$22	$3	$0	$0	$0	$0
	Admin. & General Expenses - Labor Related								
57	Administrative & General Salaries	$465	$327	$113	$25	$0	$0	$0	$0
58	Office Supplies & Expenses	$63	$45	$15	$3	$0	$0	$0	$0
59	Outside Services Employed - Resid.	$14	$14	$0	$0	$0	$0	$0	$0
60	Outside Services Employed - Labor	$284	$200	$69	$15	$0	$0	$0	$0
61	Injuries & Damages	$26	$19	$6	$1	$26	$19	$6	$1
62	Employment Pensions and Benefits	$448	$315	$109	$24	$448	$315	$109	$24
63	Rents	$314	$221	$76	$17	$0	$0	$0	$0
	Admin. & General Expenses - Plant Related								
64	Property Insurance	$92	$87	$1	$4	$0	$0	$0	$0
65	Outside Services Employed - Plant	$37	$35	$0	$2	$0	$0	$0	$0
66	Injuries & Damages	$1,136	$1,071	$13	$52	$1,136	$1,071	$13	$52
67	Misc. Maintenance Expense	$338	$317	$4	$17	$0	$0	$0	$0
	Admin. & General Expenses - Other Related								
68	Admin. Expenses Transferred	($6)	($6)	$0	$0	$0	$0	$0	$0
69	Outside Services Employed - Cust.	$5,083	$4,732	$315	$36	$0	$0	$0	$0
70	Outside Services Employed - Plant - O&M	$1,257	$1,177	$22	$58	$0	$0	$0	$0
71	Regulatory Commission Expenses	$93	$87	$2	$4	$0	$0	$0	$0
72	General Advertising Expense	$37	$34	$1	$2	$0	$0	$0	$0
73	Miscellaneous General Expenses	$37	$34	$1	$2	$0	$0	$0	$0
	Taxes - General Taxes								
74	*PA PUC Assessment*	$1,140	$805	$111	$224	$0	$0	$0	$0
75	Local Property Taxes	$18	$12	$1	$5	$0	$0	$0	$0
76	Public Utility Reality Tax	$151	$101	$9	$41	$0	$0	$0	$0
77	State Capital Stock Tax	$91	$63	$6	$22	$0	$0	$0	$0
78	Total Operating & Maintenance	$14,183	$11,931	$1,565	$687	$2,972	$2,686	$197	$89
79	Depreciation expense	$1,294	$1,197	$34	$63	$0	$0	$0	$0
80		$15,926	$13,558	$1,621	$747	$2,972	$2,686	$197	$89
81	**Total Distribution Customer**	$38,613	$34,973	$1,843	$1,797	$24,042	$22,575	$403	$1,064

OTS Exhibit No. 5
Schedule 19
page 3 of 5

Company
(In $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	OnSite Function				
82	Meters - Cost	$26,983	$18,739	$2,764	$5,480
83	Meters - Acc Depr	($12,975)	($9,011)	($1,329)	($2,635)
84	*Meteres - ADIT*	*$0*	*$0*	*$0*	*$0*
85		$14,008	$9,728	$1,435	$2,845
86	Other Rate Base	$28,506	$25,298	$1,673	$1,535
87	Total Rate Base	$42,514	$35,026	$3,108	$4,380
88	Meters / Utility Plant				
	Meters				
89	Return on Rate Base	$1,246	$865	$128	$253
90	Income Tax gross-up	$614	$426	$63	$125
91	Meters expense	$6,062	$4,193	$685	$1,184
92	Maintenance of Meters	$107	$74	$12	$21
93	Meters Depreciation exp	$797	$553	$82	$162
94		$8,826	$6,111	$970	$1,745

OTS
(In $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	OnSite Function				
82	Meters - Cost	$26,983	$18,739	$2,764	$5,480
83	Meters - Acc Depr	($12,975)	($9,011)	($1,329)	($2,635)
84	*Meteres - ADIT*	*$0*	*$0*	*$0*	*$0*
85		$14,008	$9,728	$1,435	$2,845
86	Other Rate Base	$0	$0	$0	$0
87	Total Rate Base	$14,008	$9,728	$1,435	$2,845
88	Meters / Utility Plant				
	Meters				
89	Return on Rate Base	$1,246	$865	$128	$253
90	Income Tax gross-up	$614	$426	$63	$125
91	Meters expense	$6,062	$4,193	$685	$1,184
92	Maintenance of Meters	$107	$74	$12	$21
93	Meters Depreciation exp	$797	$553	$82	$162
94		$8,826	$6,111	$970	$1,745

OTS Exhibit No. 5
Schedule 19

Company
(In $1000's)

#		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of OnSite				
95	Return on Rate Base	$2,534	$2,249	$149	$136
96	Income Tax gross-up	$1,247	$1,107	$73	$67
97	Meter Reading	$586	$546	$36	$4
98	Customer Records and Collection	$10,271	$9,561	$636	$74
99	Uncollectible Accounts	$25,050	$23,515	$540	$995
	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
100	Operation Supv & Engineering	$117	$80	$13	$24
101	Customer Installation Expense	$62	$62	$0	$0
102	Other Expenses - Safety & Environmental	$172	$123	$18	$31
103	Other Expenses	$177	$127	$18	$32
104	Distribution Rents	$39	$27	$4	$8
105	Maintenance of Services	$663	$626	$6	$31
	Customer Accounts Expenses				
106	Customer Service - Administrative	$226	$210	$14	$2
	Admin. & General Expenses - Labor Related				
107	Administrative & General Salaries	$2,762	$2,305	$222	$235
108	Office Supplies & Expenses	$380	$317	$31	$32
109	Outside Services Employed - Resid.	$84	$84	$0	$0
110	Outside Services Employed - Labor	$1,691	$1,411	$136	$144
111	Injuries & Damages	$157	$131	$13	$13
112	Employment Pensions and Benefits	$2,663	$2,222	$214	$227
113	Rents	$1,871	$1,562	$150	$159
	Admin. & General Expenses - Plant Related				
114	Property Insurance	$20	$15	$2	$3
115	Outside Services Employed - Plant	$8	$6	$1	$1
116	Injuries & Damages	$251	$189	$21	$41
117	Misc. Maintenance Expense	$74	$56	$6	$12
	Admin. & General Expenses - Other Related				
118	Admin. Expenses Transferred	($6)	($4)	($1)	($1)
119	Outside Services Employed - Plant - O&M	$1,167	$859	$108	$200
120	Regulatory Commission Expenses	$86	$63	$8	$15
121	General Advertising Expense	$34	$25	$3	$6
122	Miscellaneous General Expenses	$25	$19	$2	$4
	Taxes - General Taxes				
123	Local Property Taxes	$4	$3	$0	$1
124	Public Utility Reality Tax	$33	$25	$3	$5
125	State Capital Stock Tax	$33	$25	$3	$5
126	Total Operating & Maintenance	$12,793	$10,567	$996	$1,230
127	Depreciation expense	$3,264	$2,869	$210	$185
128	Additional expense	$1,103	$1,103	$0	$0
129		$56,848	$51,517	$2,640	$2,691
130	**Total OnSite Customer**	$65,674	$57,628	$3,610	$4,436
	Summary of Customer Costs				
131	Distribution Customer	$38,613	$34,973	$1,843	$1,797
132	OnSite Customer	$65,674	$57,628	$3,610	$4,436
	Other Revenue				
133	Forfeited Discounts	$0	$0	$0	$0
134	Miscellaneous Service Rev.	$0	$0	$0	$0
135	Other Operating Revenue	$0	$0	$0	$0
136	Total Other Revenue	$0	$0	$0	$0
137	Total Customer Component	$104,287	$92,601	$5,453	$6,232
138	Average Bills X 1000	3,084	2,871	191	22
139	Average Monthly Cost	$33.81	$32.25	$28.57	$281.78

OTS
(In $1000's)

#		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of OnSite				
95	Return on Rate Base	$0	$0	$0	$0
96	Income Tax gross-up	$0	$0	$0	$0
97	Meter Reading	$586	$546	$36	$4
98	Customer Records and Collection	$10,271	$9,561	$636	$74
99	Uncollectible Accounts	$25,050	$23,515	$540	$995
	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
100	Operation Supv & Engineering	$0	$0	$0	$0
101	Customer Installation Expense	$62	$62	$0	$0
102	Other Expenses - Safety & Environmental	$0	$0	$0	$0
103	Other Expenses	$0	$0	$0	$0
104	Distribution Rents	$0	$0	$0	$0
105	Maintenance of Services	$663	$626	$6	$31
	Customer Accounts Expenses				
106	Customer Service - Administrative	$226	$210	$14	$2
	Admin. & General Expenses - Labor Related				
107	Administrative & General Salaries	$0	$0	$0	$0
108	Office Supplies & Expenses	$0	$0	$0	$0
109	Outside Services Employed - Resid.	$0	$0	$0	$0
110	Outside Services Employed - Labor	$0	$0	$0	$0
111	Injuries & Damages	$157	$131	$13	$13
112	Employment Pensions and Benefits	$2,663	$2,222	$214	$227
113	Rents	$0	$0	$0	$0
	Admin. & General Expenses - Plant Related				
114	Property Insurance	$0	$0	$0	$0
115	Outside Services Employed - Plant	$0	$0	$0	$0
116	Injuries & Damages	$251	$189	$21	$41
117	Misc. Maintenance Expense	$0	$0	$0	$0
	Admin. & General Expenses - Other Related				
118	Admin. Expenses Transferred	$0	$0	$0	$0
119	Outside Services Employed - Plant - O&M	$0	$0	$0	$0
120	Regulatory Commission Expenses	$0	$0	$0	$0
121	General Advertising Expense	$0	$0	$0	$0
122	Miscellaneous General Expenses	$0	$0	$0	$0
	Taxes - General Taxes				
123	Local Property Taxes	$0	$0	$0	$0
124	Public Utility Reality Tax	$0	$0	$0	$0
125	State Capital Stock Tax	$0	$0	$0	$0
126	Total Operating & Maintenance	$4,022	$3,439	$269	$314
127	Depreciation expense	$0	$0	$0	$0
128	Additional expense	$0	$0	$0	$0
129		$39,929	$37,061	$1,481	$1,387
130	**Total OnSite Customer**	$48,755	$43,172	$2,451	$3,132
	Summary of Customer Costs				
131	Distribution Customer	$24,042	$22,575	$403	$1,064
132	OnSite Customer	$48,755	$43,172	$2,451	$3,132
	Other Revenue				
133	Forfeited Discounts	($1,558)	($1,462)	($34)	($62)
134	Miscellaneous Service Rev.	($1,208)	($1,163)	($40)	($5)
135	Other Operating Revenue	($61)	($43)	($6)	($12)
136	Total Other Revenue	($2,827)	($2,668)	($80)	($79)
137	Total Customer Component	$69,970	$63,079	$2,774	$4,117
138	Average Bills X 1000	3,084	2,871	191	22
139	Average Monthly Cost	$22.69	$21.97	$14.52	$187.14

Equitable Gas Company

OTS Proposed Customer Charges and Commodity Charges

Pro-Forma Test Year Ended December 31, 2008

			Company Present Rates					Company Proposed Rates				OTS Proposed Rates			
	Rate RS - Residential Service (A)	No. of Bills (B)	Present Rates (C)	Annualized and Normalized Volumes (Mcf) (D)	Present Revenue (E)	FTY Pro Forma Adjustments (F)	Annualized and Normalized FTY Revenue (G)	Company Proposed Rates (H)	Company Proposed Revenue (I)	Company Proposed Revenue Increase (J)	% Increase (K)	OTS Proposed Rates (L)	OTS Proposed Revenue (M)	OTS Proposed Revenue Increase (N)	% Increase (O)
1		207,885 Customers		18,325,043											
2	*Monthly Service Charge*	2,494,614 (207,885 customers)	$11.85		$29,062,253		$29,062,253	$20.00	$49,892,280	$20,830,027	71.7%	$15.00	$37,419,210	$8,356,957	28.8%
	Commodity Charge:														
3	Delivery Charge		$2.703	18,325,043	$49,532,592	$861,277	$50,393,869	$2.698	$49,435,470	($958,400)	-1.9%	$3.378	$61,908,541	$11,514,671	22.8%
4	Rider C - Transporation Cost		$0.227	18,325,043	$4,159,785	($4,159,785)	($0)	-			-100.0%	-			-100.0%
5	Subtotal		$2.930		$53,692,377		$50,393,869	$2.698	$49,435,470			$3.378	$61,908,541		
6	Rider D - Universal Service		$0.580	18,325,043	$10,628,525		$10,628,525	$1.438	$26,358,742	$15,730,217	148.0%	$1.438	$26,358,742	$15,730,217	148.0%
7	Total Commodity (non-gas)		$3.510	18,325,043	$64,320,901		$61,022,394		$75,794,212	$14,771,818	24.2%		$88,267,283	$27,244,889	44.6%
8	Subtotal Non-Gas (Line 2 + Line 7)				$93,383,154		$90,084,647		$125,686,492	$35,601,845	39.5%		$125,686,493	$35,601,846	39.5%
9	Rider A - Natural Gas Supply		$13.970	18,325,043	$256,000,857	$3,298,508	$259,299,364	$13.970	$259,299,364	$0	0.0%	$13.970	$259,299,364	$0	0.0%
10	Subtotal Gas Supply				$256,000,857		$259,299,364		$259,299,364	$0	0.0%		$259,299,364	$0	0.0%
11	STAS				($314,446)		($314,446)		$168	$314,614			$168	$314,614	
12	Total Rate RS				$349,069,566		$349,069,566		$384,986,025	$35,916,459	10.3%		$384,986,025	$35,916,459	10.3%

			Company Present Rates					Company Proposed Rates				OTS Proposed Rates			
	Rate GSS - General Service Small (A)	No. of Bills (B)	Present Rates (C)	Annualized and Normalized Volumes (Mcf) (D)	Present Revenue (E)	FTY Pro Forma Adjustments (F)	Annualized and Normalized FTY Revenue (G)	Company Proposed Rates (H)	Company Proposed Revenue (I)	Company Proposed Revenue Increase (J)	% Increase (K)	OTS Proposed Rates (L)	OTS Proposed Revenue (M)	OTS Proposed Revenue Increase (N)	% Increase (O)
13		13,772 Customers		2,786,472											
14	Monthly Service Charge	153,228	$17.00		$2,604,876		$2,604,876	$23.00	$3,524,244	$919,368	35.3%	$17.00	$2,604,876	$0	0.0%
15		12,036 (13,772 customers)	$28.00		$337,008		$337,008	$34.00	$409,224	$72,216	21.4%	$28.00	$337,008	$0	0.0%
	Commodity Charge:														
16	Delivery Charge		$2.737	2,786,472	$7,626,573	($27,865)	$7,598,708	$2.795	$7,789,581	$190,873	2.5%	$3.151	$8,781,165	$1,182,457	15.6%
17	Rider C - Transporation Cost		$0.170	2,786,472	$473,700	($473,700)	$0	-	$0		-100.0%	-	$0		-100.0%
18	Total Commodity (non-gas)		$2.907		$8,100,273		$7,598,708	$2.795	$7,789,581	$190,873	2.5%	$3.151	$8,781,165	$1,182,457	15.6%
19	Subtotal Non-Gas				$11,042,157		$10,540,592		$11,723,049	$1,182,457	11.2%		$11,723,049	$1,182,457	11.2%
20	Rider A - Natural Gas Supply		$13.970	2,786,472	$38,927,009	$501,565	$39,428,574	$13.970	$39,428,574	$0	0.0%	$13.970	$39,428,574	$0	0.0%
21	Subtotal Gas Supply				$38,927,009		$39,428,574		$39,428,574	$0	0.0%		$39,428,574	$0	0.0%
22	STAS				($44,972)		($44,972)		$0	$44,972			$0	$44,972	
23	Total Rate GSS				$49,924,194		$49,924,194		$51,151,623	$1,227,429	2.5%		$51,151,623	$1,227,429	2.5%

OTS Exhibit No. 5
Schedule 20

OTS Exhibit No. 5
Schedule 21

Equitable Gas Company
Comparison of Company Present and Proposed and OTS Proposed Bills
Rate RS - Residential Service
Pro-Forma Test Year Ended December 31, 2008

	Residential Monthly Usage (Mcf)	Rate RS-Residential			Company Increase		OTS Increase	
		Company Present	Company Proposed	OTS Proposed	Amount	Percent	Amount	Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	0	$11.65	$20.00	$15.00	$8.35	72%	$3.35	29%
2	1	$29.13	$38.11	$33.79	$8.98	31%	$4.66	16%
3	2	$46.61	$56.21	$52.57	$9.60	21%	$5.96	13%
4	3	$64.09	$74.32	$71.36	$10.23	16%	$7.27	11%
5	4	$81.57	$92.42	$90.14	$10.85	13%	$8.57	11%
6	5	$99.05	$110.53	$108.93	$11.48	12%	$9.88	10%
7	6	$116.53	$128.64	$127.72	$12.11	10%	$11.19	10%
8	7	$134.01	$146.74	$146.50	$12.73	10%	$12.49	9%
9	8	$151.49	$164.85	$165.29	$13.36	9%	$13.80	9%
10	9	$168.97	$182.95	$184.07	$13.98	8%	$15.10	9%
11	10	$186.45	$201.06	$202.86	$14.61	8%	$16.41	9%
12	11	$203.93	$219.17	$221.65	$15.24	7%	$17.72	9%
13	12	$221.41	$237.27	$240.43	$15.86	7%	$19.02	9%
14	13	$238.89	$255.38	$259.22	$16.49	7%	$20.33	9%
15	14	$256.37	$273.48	$278.00	$17.11	7%	$21.63	8%
16	15	$273.85	$291.59	$296.79	$17.74	6%	$22.94	8%
17	16	$291.33	$309.70	$315.58	$18.37	6%	$24.25	8%
18	17	$308.81	$327.80	$334.36	$18.99	6%	$25.55	8%
19	18	$326.29	$345.91	$353.15	$19.62	6%	$26.86	8%
20	19	$343.77	$364.01	$371.93	$20.24	6%	$28.16	8%
21	20	$361.25	$382.12	$390.72	$20.87	6%	$29.47	8%
22	21	$378.73	$400.23	$409.51	$21.50	6%	$30.78	8%
23	22	$396.21	$418.33	$428.29	$22.12	6%	$32.08	8%
24	23	$413.69	$436.44	$447.08	$22.75	5%	$33.39	8%
25	24	$431.17	$454.54	$465.86	$23.37	5%	$34.69	8%
26	25	$448.65	$472.65	$484.65	$24.00	5%	$36.00	8%

OTS Statement No. 5-SR
Witness: Jeremy B. Hubert

11/18/08
ABG, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Surrebuttal Testimony

of

Jeremy B. Hubert

Office of Trial Staff

Concerning:

Forfeited Discounts
Rate Base
Weather Normalization Adjustment
Customer Charges

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. ARE YOU THE SAME JEREMY B. HUBERT WHO SUBMITTED OTS STATEMENT NO. 5 AND OTS EXHIBIT NO. 5 ON OCTOBER 8, 2008?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony of Robert M. Narkevic, identified as Equitable Statement No. 3-R, the rebuttal testimony of Carol B. Gras identified as Equitable Statement No. 4-R, and the rebuttal testimony of Russell A. Feingold identified as Equitable Statement No. 6-R that were submitted on behalf of Equitable Gas Company.

<u>FORFEITED DISCOUNTS</u>

Q. WHAT AMOUNT OF REVENUE FROM FORFEITED DISCOUNTS DID THE COMPANY CLAIM FOR THE TEST YEAR ENDING DECEMBER 31, 2008?

A. The Company is projecting that it will have $1,557,851 in revenues from forfeited discounts for the test year ending December 31, 2008. This amount is equal to 0.337% ($1,557,851 / $461,611,292) of total sales revenue.

Q. WHAT INCREASE IN REVENUE FROM FORFEITED DISCOUNTS DID YOU RECOMMEND UNDER PROPOSED RATES FOR THE TEST YEAR ENDING DECEMBER 31, 2008?

A. I recommended that revenue from forfeited discounts under proposed rates be increased to $1,932,397 for the test year ending December 31, 2008. This amount is $374,546 more than the $1,557,851 claimed by the Company and is equal to 0.419% of total sales revenue (OTS Ex. No. 5, Sch. 1).

Q. HAS THE COMPANY ADDRESSED YOUR RECOMMENDATION TO INCREASE THE REVENUE FROM FORFEITED DISCOUNTS BY $374,546?

A. Yes. Equitable witness Narkevic states that the Company's percentage of forfeited discounts to sales revenue has been shown to be consistently decreasing over the last five years. He further expresses his belief that my proposal to increase revenues from forfeited discounts is unreasonable due to the Company's continuing efforts to collect outstanding balances, the additional customers that are projected to be enrolled in CAP, and the enhancements to several areas of customer services.

Q. DO YOU HAVE ANY COMMENTS RELATIVE TO FORFEITED DISCOUNTS?

A. Yes. As stated previously within my direct testimony, as revenues from sales increase, revenues from forfeited discounts should increase as well. It is rational to believe that a customer's payment pattern will not change, and therefore increasing sales revenue through a rate increase will cause forfeited discounts revenue to increase over time. Over the past five years the percentage of forfeited discounts to total sales revenue has been decreasing, but has held relatively steady during the past three years between 0.407% and 0.431%. In fact, the decrease in the percentage of forfeited discounts to total revenue over that three-year period amounts to 5.6% ((0.431% - 0.407%)/0.431%). This is an average decrease of 1.9% per year over that three-year period. My adjustment, which is based on the normalized ratio of forfeited discounts to total revenues, results in a ratio of 0.419%, which indicates a decrease of 2.8% ((0.431% – 0.419%)/0.431%) from the level experienced in 2005. That amounts to an average decrease of 0.7% over the 2005 through 2008 time period. The Company's ratio of 0.337%, based on not increasing the level of forfeited discounts, indicates a decrease of 21.8% ((0.431% - 0.337%)/0.431%) from the level experienced in 2005. That amounts to an average decrease of 5.5% over the 2005 through 2008 period. This is well above the experienced level over a period in which the Company experienced no increase in base rates. The last base rate case for Equitable was based on a future test year ended September 30, 1997, which was nearly 11 years ago. This base rate increase coupled with a bad economy only increases the likelihood that the revenue generated from forfeited discounts will increase.

GAS STORAGE INVENTORY

Q. WHAT AMOUNT OF GAS STORAGE INVENTORY DID THE COMPANY CLAIM FOR THE TEST YEAR ENDING DECEMBER 31, 2008?

A. The Company's original rate base claim of $583,252,589 includes $75,175,769 worth of Gas Storage Inventory (Equitable Exhibit I, Item I-A-2, Sheet 2 of 3).

Q. WHAT ADJUSTMENT DID YOU RECOMMEND FOR THE COMPANY'S CLAIMED AMOUNT OF GAS STORAGE INVENTORY TO REFLECT ACTUAL UPDATED AMOUNTS FOR GAS STORED UNDERGROUND?

A. I recommended that the 13-month average balance for gas inventory be reduced by $12,815,557 [$75,175,769 – $62,360,212] in order to reflect data through June 2008 (OTS Ex. No. 5, Sch. 3). This time period represents the most current data available at the time of my direct testimony.

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION IN ITS REBUTTAL TESTIMONY?

A. Yes. Equitable witness Gras believes that the Company should be permitted to estimate the level of gas inventory for the months of October, November, and December of 2008 and include the estimated amount in rate base (Equitable St. No. 4-R, pp. 4-5).

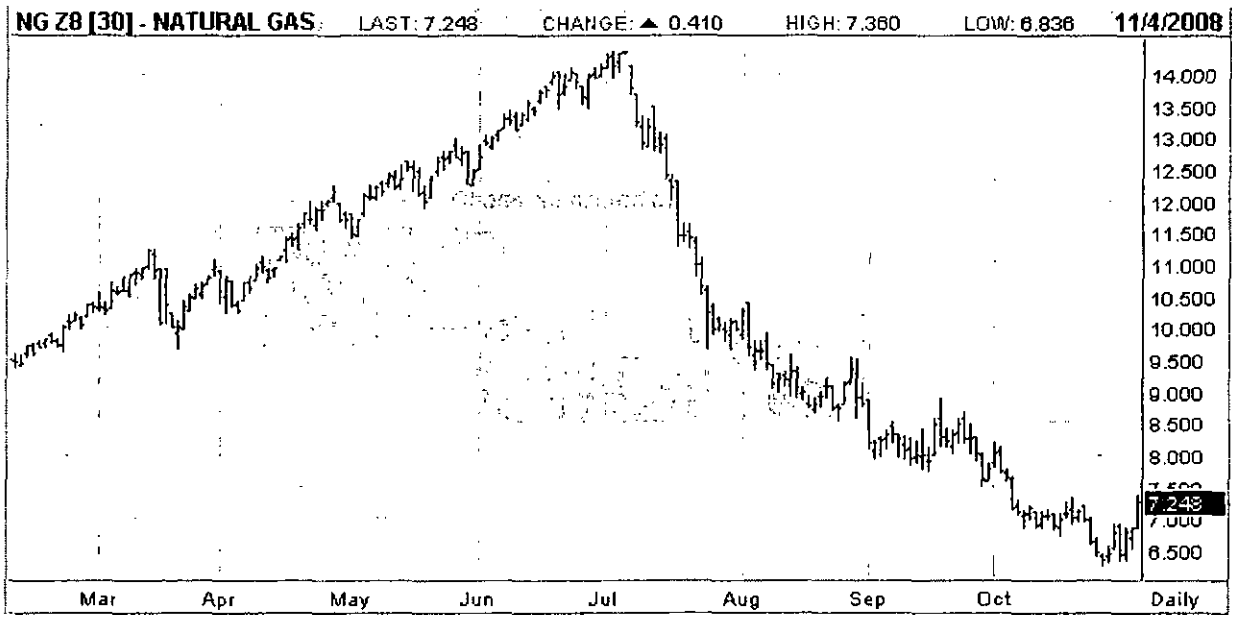
Q. HAS THE COMPANY PROPOSED ANY CHANGES TO ITS CLAIM FOR GAS INVENTORY?

A. Yes. Equitable witness Gras has presented adjustments to the gas storage inventory in Schedule CBG-2 of Equitable Statement No. 4-R. As shown in Schedule CBG-2, the Company has made revisions to its gas storage inventory to include actual data from December 2007 through September 2008 and to reflect the price of natural gas as of September 2008 in the projections for October 2008 through December 2008. This revision is shown as a $5,352,159 decrease to the Company's original 13-month average balance for gas inventory to produce a 13-month average balance for gas inventory of $69,823,610 ($75,175,769 - $5,352,159).

Q. DO YOU AGREE WITH MS. GRAS' BELIEF THAT THE COMPANY SHOULD BE PERMITTED TO ESTIMATE THE LEVEL OF GAS INVENTORY FOR THE MONTHS OF OCTOBER, NOVEMBER, AND DECEMBER OF 2008 AND INCLUDE THE ESTIMATED AMOUNT IN RATE BASE?

A. No. I disagree with Ms. Gras' position and I will further address support for my position that the Company should reflect actual book balances (quantity and price) for gas inventories. NYMEX prices are volatile, and therefore are subject to increases or decreases. As can be seen in the following chart provided by FutureSource.com, the price per dekatherm (Dth) of natural gas has fallen by 46 %

since the beginning of July from $13.500 / Dth to $7.248 / Dth on November 4, 2008. Because of its volatile nature, it is an unreliable method, and therefore, I believe it is unrealistic for Equitable to project the 13-month average balance for gas storage inventory using estimated future prices for natural gas.



Q. ARE THERE ANY COMMISSION REGULATIONS WHICH SPECIFY WHAT GAS PRICES MUST BE USED TO CALCULATE THE VALUE OF THE FUEL INVENTORIES INCLUDED IN RATE BASE?

A. Yes. Pursuant to the filing requirements within the Commission Regulations set forth at 52 Pa. Code §53.53, Exhibit A.I.A, p. 53-23, future prices for fuel inventory may not be used when calculating the value of fuel inventories included in rate base, and is stated as follows:

> 16. If fuel stocks comprise part of the cash working capital claim, provide an exhibit showing the actual book balances (quantity and price) for the fuel inventories by type of fuel for the thirteen months prior to the end of the test year by location, station, etc.

Q. MR. HUBERT, DO YOU HAVE AN UPDATE TO YOUR RECOMMENDATION TO REDUCE THE COMPANY'S CLAIM FOR GAS STORAGE INVENTORY?

A. Yes. The revised schedule is contained in OTS Exhibit No. 5-SR, Schedule 1, and reflects a reduction to the Company's original claim for gas inventory of $6,448,336 ($75,175,769– $68,727,433).

Q. WHY HAVE YOU DECIDED TO UPDATE YOUR RECOMMENDATION?

A. My updated recommendation to reduce the Company's original claim for gas inventory by $6,448,336 reflects the actual book balances for the gas inventories for the thirteen months ended September 2008, which was made possible by the updated actual gas inventory levels that are presented in Schedule CBG-2 of Equitable Statement No. 4-R. I believe the most current data is necessary to reflect the proper recommendation.

<u>CUSTOMER DEPOSITS</u>

Q. WHAT AMOUNT OF CUSTOMER DEPOSITS DID THE COMPANY CLAIM FOR THE TEST YEAR ENDING DECEMBER 31, 2008?

A. The Company's original rate base claim of $583,252,589 includes a deduction for customer deposits in the amount of $3,369,694 (Equitable Exhibit I, Item I-A-2, Sheet 2 of 3).

Q. WHAT ADJUSTMENT DID YOU RECOMMEND FOR THE COMPANY'S CLAIMED AMOUNT OF CUSTOMER DEPOSITS TO REFLECT ACTUAL UPDATED AMOUNTS FOR CUSTOMER DEPOSITS?

A. I recommended that the 13-month average balance for customer deposits be increased by $164,315 [$3,369,694 – $3,534,009] in order to reflect data through June 2008 (OTS Ex. No. 5, Sch. 5).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION IN ITS REBUTTAL TESTIMONY?

A. Yes. Equitable witness Gras believes that the Company should be permitted to estimate the level of customer deposits for the months of October, November, and December of 2008 and include the estimated amount in rate base (Equitable St. No. 4-R, pp. 5-6).

Q. HAS THE COMPANY PROPOSED ANY CHANGES TO ITS CLAIM FOR CUSTOMER DEPOSITS?

A. Yes. Equitable witness Gras has presented an adjusted claim for customer deposits in Schedule CBG-3 of Equitable Statement No. 4-R. As shown in Schedule CBG-3, the Company has made revisions to customer deposits to reflect the actual balance of customer deposits from December 2007 to September 2008, with projections for October, November, and December 2008 trended off of October – December 2007 activity. This revision is shown as a $153,197 decrease to the Company's original 13-month average balance for customer deposits to produce a 13-mongh average balance for customer deposits of $3,216,497 ($3,369,694 - $153,197).

Q. DO YOU AGREE WITH MS. GRAS' BELIEF THAT THE COMPANY SHOULD BE PERMITTED TO ESTIMATE THE LEVEL OF CUSTOMER DEPOSITS FOR THE MONTHS OF OCTOBER, NOVEMBER, AND DECEMBER OF 2008 AND INCLUDE THE ESTIMATED AMOUNT IN RATE BASE?

A. No. I disagree with Ms. Gras' position and I will further address support for my position that the Company should reflect actual book balances for customer deposits.

Q. MR. HUBERT, DO YOU HAVE AN UPDATE TO YOUR RECOMMENDATION TO REDUCE THE COMPANY'S CLAIM FOR CUSTOMER DEPOSITS?

A. Yes. The revised schedule is contained in OTS Exhibit No. 5-SR, Schedule 2, and reflects an increase to the Company's original claim for customer deposits of $37,251 ($3,406,945– $3,369,694).

Q. WHY HAVE YOU DECIDED TO UPDATE YOUR RECOMMENDATION?

A. My updated recommendation to increase the Company's original claim for customer deposits by $37,251 reflects the actual book balances for customer deposits for the thirteen months ended September 2008, which was made possible by the updated customer deposit levels that are presented in Schedule CBG-3 of Equitable Statement No. 4-R. This methodology is consistent with the methodology that is used to calculate the amount of Gas Inventory in rate base. The argument is the same in this instance. Use of projected data is unreliable and will distort the proper levels of customer deposits to be used in this proceeding.

<u>POST FUTURE TEST YEAR PLANT ADDITIONS</u>

Q. DID YOU ADDRESS POST FUTURE TEST YEAR PLANT ADDITIONS IN YOUR DIRECT TESTIMONY?

A. Yes. I recommended that the Company's $13,151,140 in Post Future Test Year Plant Additions and $639,933 of corresponding annual depreciation expense be removed from the Company's claim (OTS St. No. 5, pp. 13-19).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION CONCERNING POST FUTURE TEST YEAR PLANT ADDITIONS?

A. Yes. The Company does not agree with my recommendation and offered several arguments why it should be permitted to include Post Test Year Plant Additions in its Measure of Value.

Q. WHAT IS THE FIRST ISSUE THE COMPANY ADDRESSES TO JUSTIFY INCLUDING POST TEST YEAR PLANT ADDITIONS?

A. The Company states that my admission that the Commission has allowed claimed expenditures to complete Construction Work in Progress ("CWIP") that will be in progress during the future test year and in service shortly thereafter, somehow justifies the inclusion of Post Test Year Plant additions in this case (Equitable St. No. 4-R, p. 7).

Q. DOES THE FACT THE COMMISSION HAS ALLOWED CLAIMED EXPENDITURES TO COMPLETE CWIP THAT WILL BE IN PROGRESS DURING THE FUTURE TEST YEAR AND IN SERVICE SHORTLY THEREAFTER JUSTIFY INCLUDING POST TEST YEAR PLANT ADDITIONS IN THIS CASE?

A. No. Ms. Gras' claim that these projected post test year plant additions should be considered CWIP is not supported in the filing or testimony. Pursuant to the filing requirements within the Commission Regulations set forth at 52 Pa. Code §53.53, Exhibit A.I.A, page 53-23, in order to be considered CWIP plant additions must *reflect specific projects and must not be solely based upon mathematical* calculations, and is stated as follows:

> 13. If a claim is made for non-revenue producing construction work in progress, include, in the form of an exhibit, the summary page *from all work orders, amount expended at the end of the test year* and anticipated in-service dates. Indicate if any of the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary *page from the work order. Include final completion date and* estimated total amounts to be spent on each project.

Q. WHAT IS THE SECOND ISSUE THE COMPANY ADDRESSES TO JUSTIFY INCLUDING POST TEST YEAR PLANT ADDITIONS?

A. The Company claims that there is no mismatch between the Post Test Year Plant Additions and the other part of the rate making equation, such as expenses and rate of return (Equitable St. No. 4-R, p. 8).

Q. IS THE COMPANY CORRECT?

A. No. As described in my direct testimony, and upon advice of counsel, I have emphasized that plant must be "used and useful" in order to be properly included in a public utility's rate base claim. Since the Post Future Test Year Plant will not be used and useful at the end of the future test year, that amount should not be included in rate base (OTS St. No. 5, p. 15). The cost of debt and equity in a case is based on a specific point in time. Costs of debt and equity can fluctuate, especially in these uncertain economic times.

Q. WHAT IS THE THIRD ISSUE THE COMPANY ADDRESSES SEEKING TO JUSTIFY INCLUDING POST TEST YEAR PLANT ADDITIONS IN RATE BASE?

A. The Company claims that expenses associated with system maintenance are likely to increase in the future if these non-revenue generating (non-expense reducing) investments are not made by the Company to "maintain existing" customer service and system reliability, integrity, and safety (Equitable St. No. 4-R, pp. 8-9).

Q. DOES SPECULATION ABOUT A POSSIBLE FUTURE INCREASE IN AN EXPENSE JUSTIFY THE INCLUSION OF POST TEST YEAR PLANT ADDITIONS IN THIS CASE?

A. No. Maintaining existing customer service is an ongoing process, which is why in a rate case a test year concept is used. Any speculation about an expense that may increase or decrease in the future is one reason for the use of a normalized test year for determining utility rates. Any quantification about a speculative claimed expense increase should not be part of the ratemaking formula since other expenses can also be speculated to decrease in the future. Also, while the "intent" may not be to improve reliability integrity, safety, and reduce expenses, the Company has not denied that this is certainly possible.

Q. IS IT REASONABLE TO ASSUME THAT THE COMPANY HAS BEEN ABLE TO UTILIZE EXPENSE REDUCTIONS AND REVENUE INCREASES IN THE PAST?

A. Yes. It is reasonable to assume that since this the Company's first base rate case in eleven years, the Company during that period must have been capable of reducing either expenses and/or debt costs, and likely increased the number of customers and throughput, or utilized a combination of all of these, to ensure that revenues exceeded expenses and thereby negated the need for a base rate increases during these past eleven years.

Q. DID THE COMPANY ADDRESS YOUR CLAIM THAT IT WOULD BE REASONABLE TO BELIEVE THAT THESE POST FUTURE TEST YEAR PLANT ADDITIONS WILL ALSO REDUCE EXPENSES?

A. Yes. The Company addressed an example that I provided where it would be reasonable to believe that the Post Test Year Plant additions could also reduce expenses (Equitable St. No. 4-R, pp. 9-10).

Q. WHAT EXAMPLE DID THE COMPANY ADDRESS?

A. The Company addressed the Post Future Test Year claim of $1,000,000 for Software, which includes the Work Management System (Equitable St. No. 4-R, p. 9).

Q. DID THE COMPANY DENY THAT THE WORK MANAGEMENT SYSTEM COULD RESULT IN FEWER OVERALL EMPLOYEES, IMPROVING OVERALL SYSTEM OPERATIONS AND REDUCE EXPENSES OVER TIME?

A. No. The Company never denied that such systems could result in fewer employees, improve overall system operations and reduce expense over time. However, the Company does believe that expenses for training and deployment as well as maintenance of the new system will offset any efficiencies gained in the near future. Any offset to gained efficiencies is merely speculative, and I continue to believe that a new Work Management System should reduce expenses over time. Once employees are trained on the system the Company will realize cost savings without reflecting the lower costs in rates.

<u>RATE BASE SUMMARY</u>

Q. AS A RESULT OF DEVELOPMENTS DURING THE COURSE OF THIS PROCEEDING, WHAT IS YOUR TOTAL RATE BASE RECOMMENDATION?

A. As a result of updates provided by the Company, I have revised my total rate base recommendation to $563,615,863 which is a decrease of $19,636,726 from the Company's original rate base claim of $583,252,589 (OTS Ex. No. 5-SR, Sch. 3, line 22).

WEATHER NORMALIZATION

Q. WHAT IS THE NUMBER OF HEATING DEGREE DAYS USED BY EQUITABLE IN ITS PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. The Company used 5,541 heating degree days (Equitable St. No. 3, p. 7). The 5,541 heating degree days is based on a simple average of monthly heating degree days measured over the past 20 years obtained from the NOAA through its weather station located at the Pittsburgh International Airport ("PIT").

Q. WHAT IS THE NUMBER OF HEATING DEGREE DAYS THAT YOU RECOMMENDED IN YOUR DIRECT TESTIMONY?

A. I recommended the use a rolling NOAA 30-year average for 1978-2007 of 5,678 heating degree days.

Q. HAS THE COMPANY ADDRESSED YOUR RECOMMENDATION TO USE A ROLLING 30-YEAR AVERAGE FOR 1978-2007 OF 5,678 HEATING DEGREE DAYS?

A. Yes. Equitable witness Narkevic claims that a 30-year period is not a proper period to determine normal and the Company should use 20-year data to determine normal heating degree days for several reasons. First, he claims that a non-proportional level of the total heating degree days occurred in the first 10 years of the 30 year period (1978-2007). When the actual heating degree days are compared to the 30-year rolling average, eight of the first 10 years exceed the average and only 3 years out of the last 10 years exceed the average (Equitable St. No. 3-R, Ex. RNR-1). Second, Mr. Narkevic makes a comparison of the actual degree days over the last 30 years to the officially calculated NOAA 30-year average for PIT of 5,829 HDD for 1971-2000 and shows that only one year over the last 10 years exceeds the average. Lastly, Mr. Narkevic refers to a statement my direct testimony where I stated that the average of values over a 30 year period may or may not be what one would expect to occur on an annual basis and uses this statement to support his claim that the 20 year average data is more likely to be reflective of what will actually occur.

Q. IS MR. NARKEVIC'S FIRST CLAIM THAT A NON PROPORTIONAL LEVEL OF THE TOTAL HEATING DEGREE DAYS OCCURS IN THE FIRST 10 YEARS OF THE 30 YEAR PERIOD A VALID REASON?

A. No. The first 10 year period is only a snapshot of thc 30 year period that encompasses a length of time which is sufficient to smooth out short term aberrations of data. Looking at the full 30 year time period, it can be shown that the ratio of the years that the actual HDD exceeds the 30 year average HDD to the years that the actual HDD is below the 30 year average HDD is nearly 50/50. 16 years are shown to be warmer than average, and 14 years are shown to be colder than average (Equitable St. No. 3-R, Ex. RNR-1).

Q. LOOKING AT HIS SECOND REASON, IS THERE ANY SIGNIFICANCE IN THE FACT THAT ONLY ONE YEAR OVER THE PAST 10 YEARS EXCEEDS THE OFFICIALLY CALCULATED NOAA 30-YEAR AVERAGE FOR PIT OF 5,829 FOR 1971 - 2000?

A. No. I agree with his conclusion that the 30 year periods of 1971-2000 and 1978-2007 are statistically different. What follows from that statistical finding is that the past does not predict the future, rather than his conclusion that the more recent 20 year data is appropriate. Mr. Narkevic has not provided analysis which supports rejecting the use of the 30-year normals in favor of the 20-year normals he believes to be better.

Q. BASED ON MR. NARKEVIC'S OPINION THAT THE AVERAGE VALUES OVER A 30 YEAR PERIOD IS NOT WHAT ONE WOULD EXPECT TO OCCUR ON AN ANNUAL BASIS, IS IT REASONABLE TO BELIEVE THAT THE 20 YEAR AVERAGE DATA IS MORE LIKELY TO BE REFLECTIVE OF WHAT WILL ACTUALLY OCCUR?

A. No. The purpose of determining normal weather is not to predict the weather, but to determine what normal or typical weather is from year to year in the area in question.

Q. DID WITNESS NARKEVIC ADDRESS YOUR RECOMMENDATION THAT A ONE PERCENT CONSERVATION ADJUSTMENT SHOULD NOT BE INCLUDED IN THE CALCULATION OF THE NORMALIZED LOAD FOR THE FUTURE TEST YEAR?

A. Yes. Mr. Narkevic states that he does not agree with my recommendation on the basis that there is a steady 1% decline in the use per residential gas customer annually since 1980, which is shown in a study done by the American Gas Association (Equitable St. No. 3-R, p. 5).

Q. IS THIS A VALID REASON FOR INCLUDING A 1% CONSERVATION ADJUSTMENT IN THE CALCULATION OF FUTURE TEST YEAR THROUGHPUT FOR EQUITABLE GAS COMPANY?

A. No. The study prepared by the American Gas Association uses data that only represents 28% of all residential natural gas customers throughout the United States. Furthermore, the study is neither Company specific nor state specific, and therefore may not be indicative of usage in Pennsylvania.

<u>CUSTOMER CHARGES</u>

Q. PLEASE SUMMARIZE MR. FEINGOLD'S TESTIMONY.

A. In his testimony, Mr. Feingold alleges that I improperly excluded many items which he believes are direct customer costs (Equitable St. No. 6-R, pp. 18-19).

Q. WHAT RATE BASE ITEMS DID THE COMPANY CLAIM WERE INAPPROPRIATELY EXCLUDE FROM THE CUSTOMER COST ANALYSIS?

A. On page 18 of Equitable Statement No. 6-R, the Company claims I inappropriately excluded approximately \$23.447 million of Other Rate Base, \$19.928 million of Intangible Plant and \$2.739 million of General Plant. The Company explains that the \$23.447 million of "other rate base" includes such things as house regulators, house regulator installations, industrial measuring & regulating station equipment, and installations on customer premises.

Q. WHY DID YOU EXCLUDE \$23.447 MILLION WORTH OF "OTHER RATE BASE" IN THE CUSTOMER COST ANALYSIS?

A. The items included in "Other Rate Base" were not specified by the Company in the customer cost analysis. Since there was no way to determine what is included in "other rate base" and the Commission has never allowed generic plant such as "Other Rate Base" to be recovered in the customer cost, I excluded all "Other Rate Base" from the customer cost analysis.

Q. NOW THAT THE COMPANY HAS EXPLAINED WHAT IS INCLUDED IN "OTHER RATE BASE" IN ITS REBUTTAL TESTIMONY, SHOULD THE $23.447 MILLION OF OTHER PLANT AND CORRESPONDING DEPRECIATION EXPENSE BE INCLUDED IN YOUR CUSTOMER COST ANALYSIS?

A. Yes. The Company's explanation is acceptable, and the $23.447 million of house regulators, house regulator installations, industrial measuring & regulating station equipment, installations on customer premises, and the corresponding annual depreciation expense should be included in the customer cost analysis.

Q. HAVE YOU REVISED OTS EXHIBIT NO. 5, SCHEDULE 19 TO REFLECT THE INCLUSION OF $23.447 MILLION OF OTHER RATE BASE AND CORRESPONDING DEPRECIATION EXPENSE?

A. Yes. I attached OTS Exhibit No. 5-SR, Schedule 4 which shows the affect on the customer cost with the inclusion of the $23.447 million of house regulators, house regulator installations, industrial measuring & regulating station equipment, and installations on customer premises. Including this plant and corresponding depreciation expense of $1,012,000 ($832,000 + $63,000 + $117,000), shown on page 5 of OTS Exhibit No. 5-SR, Schedule 4, results in a Residential customer cost of $22.26 per month, which is approximately $0.29 per month more than I originally recommended.

Q. DOES THE INCLUSION OF THIS PLANT AND CORRESPONDING DEPRECIATION EXPENSE CAUSE YOU TO REVISE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. No. My customer charge recommendations are based on the concept of gradualism. Therefore, the inclusion of this additional plant and depreciation expense to determine the customer costs does not affect my customer charge recommendation.

Q. IS MR. FEINGOLD CORRECT THAT YOU FAILED TO INCLUDE DIRECT CUSTOMER COSTS ASSOCIATED WITH THE SERVICES PORTION OF MAINS AND SERVICES EXPENSE IN YOUR DETERMINATION OF AN APPROPRIATE CUSTOMER CHARGE?

A. No. I chose not to include customer costs associated with the services portion of mains and services expense in my determination of an appropriate customer charge. Until the Company can provide a breakdown by account rather than grouped together as "Mains and Services Expense", none of these costs should be included in the customer cost analysis and recovered in the customer charge.

Q. SHOULD THE $19.928 MILLION OF INTANGIBLE PLANT AND $2.739 MILLION OF GENERAL PLANT, DESCRIBED ABOVE, ALSO BE INCLUDED IN THE CUSTOMER COST ANALYSIS?

A. No. Intangible and General Plant are not customer costs. Direct customer costs as stated in my direct testimony, are costs that increase each time a new customer is added, or decrease when a customer is lost, which is not the case with Intangible and General Plant.

Q. PLEASE COMMENT ON MR. FEINGOLD'S CLAIM ON PAGE 22 OF EQUITABLE STATEMENT NO. 6-R THAT THE COMPANY SHOULD NOT INCLUDE OTHER REVENUE IT RECEIVES FROM CUSTOMERS AS AN OFFSET TO THE CUSTOMER COSTS DUE TO HIS BELIEF THAT OTHER REVENUE IS NOT A PREDICTABLE REVENUE SOURCE AND SHOULD NOT REDUCE THE COMPANY'S MONTHLY CUSTOMER CHARGES.

A. As stated in my direct testimony, OTS believes that that it is reasonable to include other revenue to offset the direct and indirect customer costs, due to the fact that the Company is permitted to claim uncollectible accounts expense as an indirect customer cost. The rationale for this is the recent PPL Gas base rate case at Docket R-00061398, Order entered February 8, 2007, which allowed PPL Gas to include 100% of uncollectible account expense as an indirect customer cost, despite the fact that over 90% of PPL Gas' revenue came from volumetric usage charges. Since OTS included 100% of Equitable's bad debt expense as an indirect customer cost, OTS believes it is reasonable to include $2,827,000 which is 100% of other revenue received as an offset to customer costs, regardless of the type of other revenue.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OTS Exhibit No. 5-SR
Witness: Jeremy B. Hubert

11/19/08

HBC, PA RJS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

Docket No. R-2008-2029325

Exhibit to Accompany

the

Surrebuttal Testimony

of

Jeremy B. Hubert

Office of Trial Staff

Concerning:

Forfeited Discounts
Rate Base
Weather Normalization Adjustment
Customer Charges

Equitable Gas Company
Gas Storage Inventory
R-2008-2029325

		Company Stored Underground	OTS Stored Underground	OTS Adjustment
1	September	-	$88,141,850	
2	October	-	$97,307,466	
3	November	-	$96,381,266	
4	December, 2007	-	$92,072,226	
5	January, 2008	-	$70,143,409	
6	February	-	$44,712,754	
7	March	-	$24,168,057	
8	April	-	$23,807,941	
9	May	-	$37,685,231	
10	June	-	$48,553,013	
11	July	-	$76,217,897	
12	August	-	$90,335,452	
13	September, 2008	-	$103,930,073	
14	Total	-	$893,456,635	
15	Average Monthly Balan	$75,175,769 *	$68,727,433	**($6,448,336)**

* **Reference Equitable St. No. 4, page 8**

OTS Exhibit No. 5-SR
Schedule 2

Equitable Gas Company
Future Period - 12 Months Ended December 31, 2008
Customer Deposits

		Company Customer Deposits	OTS Customer Deposits	OTS Adjustment
1	September	-	$3,473,131	
2	October	-	$3,404,897	
3	November	-	$3,364,481	
4	December, 2007	-	$3,484,804	
5	January, 2008	-	$3,527,421	
6	February	-	$3,595,878	
7	March	-	$3,669,181	
8	April	-	$3,563,416	
9	May	-	$3,573,395	
10	June	-	$3,627,300	
11	July	-	$3,712,587	
12	August	-	$2,663,195	
13	September, 2008	-	$2,630,605	
14	Total	-	$44,290,291	
15	Average Monthly Balance	$3,369,694	$3,406,945	**$37,251**

Equitable Gas Company

DOCKET NO.: R-2008-2029325

MEASURE OF VALUE SCHEDULE

Test Year Ending December 31, 2008

	(A)		(B)	(C)	(D)
			Company Claim	OTS Adjustment	OTS
1	Plant In Service				
2		*Non Depreciable Plant*	$741,784	$0	$741,784
3		Depreciable Plant	$884,061,803	$0	$884,061,803
4		Post Test Year Plant	$13,151,140	($13,151,140)	$0
5			$897,954,727	($13,151,140)	$884,803,587
6	Less: Accrued Depreciation		$289,353,072	$0	$289,353,072
7	Depreciated Plant In Service		$608,601,655	($13,151,140)	$595,450,515
8	Add:	Materials and Supplies	$887,426	$0	$887,426
9		Current Gas Storage	$75,175,769	($6,448,336)	$68,727,433
10		Cash Working Capital	$11,335,335	$0	$11,335,335
11		Prepayments	$234,270	$0	$234,270
12	Less:	Deferred Income Taxes	$104,709,261	$0	$104,709,261
13		Defferred Income Taxes-Other	$0	$0	$0
14		Deferred ITC	$4,902,910	$0	$4,902,910
15		*Customer Deposits*	$3,369,694	$37,251	$3,406,945
16		**Original Cost Measure of Value**	**$583,252,589**	**($19,636,726)**	**$563,615,863**

Equitable Gas Company

Docket No. R-2008-2029325

Cost of Service Study - Future Test Year Ended 12/31/2008

Customer Costs (Peak and Average Method)

Company
(In $1000's)

Cost of Service Study - Future Test Year Ended 12/31/2008

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs - Summary				
1	*Rate Base - Distribution*	$118,374	$111,782	$1,296	$5,296
2	Rate Base - OnSite Function	$42,514	$35,026	$3,108	$4,380
3		$160,888	$146,808	$4,404	$9,676
4	Rate of Return				
5	Return on rate base	$14,303	$13,051	$392	$860
6	*Income Tax gross-up*	$7,042	$6,426	$192	$424
7	Operating expenses - Distribution	$15,600	$13,457	$1,581	$762
8	Operating expenses - OnSite	$54,869	$48,456	$2,905	$3,508
9	Depreciation expense - Distribution	$7,109	$6,686	$91	$332
10	Depreciation expense - OnSite	$4,061	$3,422	$292	$347
11	*Additional expense*	*$1,103*	*$1,103*	*$0*	*$0*
12		$104,287	$92,601	$5,453	$6,233
	Other Revenue				
13	Forfeited Discounts	$0	$0	$0	$0
14	*Miscellaneous Service Rev.*	*$0*	*$0*	*$0*	*$0*
15	Other Operating Revenue	$0	$0	$0	$0
16	Total Other Revenue	$0	$0	$0	$0
17	Total Customer Component	$104,287	$92,601	$5,453	$6,233
18	Average Bills X 1000	3,084	2,871	191	22
19	*Average Monthly Cost*	$33.82	$32.25	$28.65	$283.32

OTS
(In $1000's)

Cost of Service Study - Future Test Year Ended 12/31/2008

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs - Summary				
1	*Rate Base - Distribution*	$114,986	$108,539	$1,127	$5,320
2	Rate Base - OnSite Function	$37,455	$29,005	$2,887	$5,563
3		$152,441	$137,544	$4,014	$10,883
4	Rate of Return				
5	Return on rate base	$11,468	$10,514	$228	$726
6	Income Tax gross-up	$5,647	$5,177	$112	$358
7	Operating expenses - Distribution	$2,972	$2,686	$197	$89
8	Operating expenses - OnSite	$46,098	$41,328	$2,178	$2,592
9	Depreciation expense - Distribution	$5,815	$5,489	$57	$269
10	Depreciation expense - OnSite	$1,809	$1,385	$145	$279
11	*Additional expense*	*$0*	*$0*	*$0*	*$0*
12		$73,809	$66,579	$2,917	$4,313
	Other Revenue				
13	Forfeited Discounts	($1,558)	($1,462)	($34)	($62)
14	*Miscellaneous Service Rev.*	*($1,208)*	*($1,163)*	*($40)*	*($5)*
15	Other Operating Revenue	($61)	($43)	($6)	($12)
16	Total Other Revenue	($2,827)	($2,668)	($80)	($79)
17	Total Customer Component	$70,982	$63,911	$2,837	$4,234
18	Average Bills X 1000	3,084	2,871	191	22
19	Average Monthly Cost	$23.02	$22.26	$14.85	$192.45

OTS Exhibit No. 5-SR
Schedule 4
page 1 of 5

Company
(In $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Distribution Function				
20	Mains - Cost	$0	$0	$0	$0
21	Mains - Acc Depr	$0	$0	$0	$0
22	Mains - ADIT	$0	$0	$0	$0
23		$0	$0	$0 #	$0
24	Services - Cost**	$226,432	$213,758	$2,209	$10,465
25	Services - Acc Depr	($83,524)	($78,849)	($815)	($3,860)
26	Services - ADIT	($27,922)	($26,370)	($267)	($1,285)
27		$114,986	$108,539	$1,127	$5,320
28	Other Rate Base	$3,388	$3,243	$169	($24)
29	Total Rate Base	$118,374	$111,782	$1,296	$5,296
	Mains				
30	Return on Rate Base	$0	$0	$0	$0
31	Income Tax gross-up	$0	$0	$0	$0
32	Maintenance of Mains	$0	$0	$0	$0
33	Mains & Services expense	$0	$0	$0	$0
34	Mains Depreciation exp	$0	$0	$0	$0
35		$0	$0	$0	$0
	Services				
36	Return on Rate Base	$10,222	$9,649	$100	$473
37	Income Tax gross-up	$5,033	$4,751	$49	$233
38	Maintenance of Services	$0	$0	$0	$0
39	Mains & Services expense	$1,617	$1,526	$16	$75
40	Services Depreciation exp	$5,815	$5,489	$57	$269
41		$22,687	$21,415	$222	$1,050

OTS
(In $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Distribution Function				
20	Mains - Cost	$0	$0	$0	$0
21	Mains - Acc Depr	$0	$0	$0	$0
22	Mains - ADIT	$0	$0	$0	$0
23		$0	$0	$0 #	$0
24	Services - Cost	$226,432	$213,758	$2,209	$10,465
25	Services - Acc Depr	($83,524)	($78,849)	($815)	($3,860)
26	Services - ADIT	($27,922)	($26,370)	($267)	($1,285)
27		$114,986	$108,539	$1,127	$5,320
28	Other Rate Base	$0	$0	$0	$0
29	Total Rate Base	$114,986	$108,539	$1,127	$5,320
	Mains				
30	Return on Rate Base	$0	$0	$0	$0
31	Income Tax gross-up	$0	$0	$0	$0
32	Maintenance of Mains	$0	$0	$0	$0
33	Mains & Services expense	$0	$0	$0	$0
34	Mains Depreciation exp	$0	$0	$0	$0
35		$0	$0	$0	$0
	Services				
36	Return on Rate Base	$10,222	$9,649	$100	$473
37	Income Tax gross-up	$5,033	$4,751	$49	$233
38	Maintenance of Services	$0	$0	$0	$0
39	Mains & Services expense	$0	$0	$0	$0
40	Services Depreciation exp	$5,815	$5,489	$57	$269
41		$21,070	$19,889	$206	$975

Company
(In $1000's)

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of Distribution				
42	Return on Rate Base	$301	$288	$15	($2)
43	Income Tax gross-up	$148	$142	$7	($1)
44	Uncollectible Accounts	$0	$0	$0	$0
45	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
46	Operation Supv & Engineering	$526	$497	$5	$24
47	Other Expenses - Safety & Environmental	$65	$60	$2	$3
48	Other Expenses	$67	$62	$2	$3
49	Distribution Rents	$179	$169	$2	$8
50	Maint. Supervision & Engineering	$152	$107	$37	$8
51	Maint. Of Stuctures & Improvements	$165	$155	$2	$8
52	Maintenance of Other Equipment	$21	$20	$0	$1
	Customer Services & Informational Exp.				
53	Customer Assist. - Other	$510	$474	$32	$4
54	Other Cust. Service & Informational Exp.	$698	$698	$0	$0
55	Demonstration	$659	$0	$591	$68
56	Advertising Expense	$25	$0	$22	$3
	Admin. & General Expenses - Labor Related				
57	Administrative & General Salaries	$465	$327	$113	$25
58	Office Supplies & Expenses	$63	$45	$15	$3
59	Outside Services Employed - Resid.	$14	$14	$0	$0
60	Outside Services Employed - Labor	$284	$200	$69	$15
61	Injuries & Damages	$26	$19	$6	$1
62	Employment Pensions and Benefits	$448	$315	$109	$24
63	Rents	$314	$221	$76	$17
	Admin. & General Expenses - Plant Related				
64	Property Insurance	$92	$87	$1	$4
65	Outside Services Employed - Plant	$37	$35	$0	$2
66	Injuries & Damages	$1,136	$1,071	$13	$52
67	Misc. Maintenance Expense	$338	$317	$4	$17
	Admin. & General Expenses - Other Related				
68	Admin. Expenses Transferred	($6)	($6)	$0	$0
69	Outside Services Employed - Cust.	$5,083	$4,732	$315	$36
70	Outside Services Employed - Plant - O&M	$1,257	$1,177	$22	$58
71	Regulatory Commission Expenses	$93	$87	$2	$4
72	General Advertising Expense	$37	$34	$1	$2
73	Miscellaneous General Expenses	$37	$34	$1	$2
	Taxes - General Taxes				
74	PA PUC Assessment	$1,140	$805	$111	$224
75	Local Property Taxes	$18	$12	$1	$5
76	Public Utility Realty Tax	$151	$101	$9	$41
77	State Capital Stock Tax	$91	$63	$6	$22
78	Total Operating & Maintenance	$14,183	$11,931	$1,565	$687
79	Depreciation expense	$1,294	$1,197	$34	$63
80		$15,926	$13,558	$1,621	$747
81	Total Distribution Customer	$38,613	$34,973	$1,843	$1,797

OTS
(In $1000's)

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of Distribution				
42	Return on Rate Base	$0	$0	$0	$0
43	Income Tax gross-up	$0	$0	$0	$0
44	Uncollectible Accounts	$0	$0	$0	$0
45	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
46	Operation Supv & Engineering	$0	$0	$0	$0
47	Other Expenses - Safety & Environmental	$0	$0	$0	$0
48	Other Expenses	$0	$0	$0	$0
49	Distribution Rents	$0	$0	$0	$0
50	Maint. Supervision & Engineering	$152	$107	$37	$8
51	Maint. Of Stuctures & Improvements	$0	$0	$0	$0
52	Maintenance of Other Equipment	$0	$0	$0	$0
	Customer Services & Informational Exp.				
53	Customer Assist. - Other	$510	$474	$32	$4
54	Other Cust. Service & Informational Exp.	$698	$698	$0	$0
55	Demonstration	$0	$0	$0	$0
56	Advertising Expense	$0	$0	$0	$0
	Admin. & General Expenses - Labor Related				
57	Administrative & General Salaries	$0	$0	$0	$0
58	Office Supplies & Expenses	$0	$0	$0	$0
59	Outside Services Employed - Resid.	$0	$0	$0	$0
60	Outside Services Employed - Labor	$0	$0	$0	$0
61	Injuries & Damages	$26	$19	$6	$1
62	Employment Pensions and Benefits	$448	$315	$109	$24
63	Rents	$0	$0	$0	$0
	Admin. & General Expenses - Plant Related				
64	Property Insurance	$0	$0	$0	$0
65	Outside Services Employed - Plant	$0	$0	$0	$0
66	Injuries & Damages	$1,136	$1,071	$13	$52
67	Misc. Maintenance Expense	$0	$0	$0	$0
	Admin. & General Expenses - Other Related				
68	Admin. Expenses Transferred	$0	$0	$0	$0
69	Outside Services Employed - Cust.	$0	$0	$0	$0
70	Outside Services Employed - Plant - O&M	$0	$0	$0	$0
71	Regulatory Commission Expenses	$0	$0	$0	$0
72	General Advertising Expense	$0	$0	$0	$0
73	Miscellaneous General Expenses	$0	$0	$0	$0
	Taxes - General Taxes				
74	PA PUC Assessment	$0	$0	$0	$0
75	Local Property Taxes	$0	$0	$0	$0
76	Public Utility Realty Tax	$0	$0	$0	$0
77	State Capital Stock Tax	$0	$0	$0	$0
78	Total Operating & Maintenance	$2,972	$2,686	$197	$89
79	Depreciation expense	$0	$0	$0	$0
80		$2,972	$2,686	$197	$89
81	Total Distribution Customer	$24,042	$22,575	$403	$1,064

Company
(In $1000's)

	Customer Costs - Details	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	OnSite Function				
82	Meters - Cost	$26,983	$16,739	$2,764	$5,480
83	Meters - Acc Depr	($12,975)	($9,011)	($1,329)	($2,635)
84	Meteres - ADIT	$0	$0	$0	$0
85		$14,008	$9,728	$1,435	$2,845
86	Other Rate Base	$28,506	$25,298	$1,673	$1,535
87	Total Rate Base	$42,514	$35,026	$3,108	$4,380
88	Meters / Utility Plant				
	Meters				
89	Return on Rate Base	$1,246	$865	$128	$253
90	*Income Tax gross-up*	$614	$426	$63	$125
91	Meters expense	$6,062	$4,193	$685	$1,184
92	Maintenance of Meters	$107	$74	$12	$21
93	Meters Depreciation exp	$797	$553	$82	$162
94		$8,826	$6,111	$970	$1,745

OTS
(In $1000's)

	Customer Costs - Details	Total	*Residential* Service (RS)	*Service* - Small (GSS)	*Service* - Large (GSL)
	OnSite Function				
82	Meters - Cost	$26,983	$18,739	$2,764	$5,480
83	Meters - Acc Depr	($12,975)	($9,011)	($1,329)	($2,635)
84	Meteres - ADIT	*$0*	*$0*	$0	$0
85		$14,008	$9,728	$1,435	$2,845
86	Other Rate Base	$23,447	$19,277	$1,452	$2,718
87	Total Rate Base	$37,455	$29,005	$2,887	$5,563
88	Meters / Utility Plant				
	Meters				
89	Return on Rate Base	$1,246	$865	$128	$253
90	Income Tax gross-up	$614	$426	$63	$125
91	*Meters expense*	$6,062	$4,193	$685	$1,184
92	Maintenance of Meters	$107	$74	$12	$21
93	Meters Depreciation exp	$797	$553	$82	$162
94		$8,826	$6,111	$970	$1,745

Company
(In $1000's)

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of OnSite				
95	Return on Rate Base	$2,534	$2,249	$149	$136
96	Income Tax gross-up	$1,247	$1,107	$73	$67
97	Meter Reading	$586	$546	$36	$4
98	Customer Records and Collection	$10,271	$9,561	$636	$74
99	Uncollectible Accounts	$25,050	$23,515	$540	$995
	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
100	Operation Supv & Engineering	$117	$80	$13	$24
101	Customer Installation Expense	$62	$62	$0	$0
102	Other Expenses - Safety & Environmental	$172	$123	$18	$31
103	Other Expenses	$177	$127	$18	$32
104	*Distribution Rents*	$39	$27	$4	$8
105	Maintenance of Services	$663	$626	$6	$31
	Customer Accounts Expenses				
106	Customer Service - Administrative	$226	$210	$14	$2
	Admin. & General Expenses - Labor Related				
107	Administrative & General Salaries	$2,762	$2,305	$222	$235
108	*Office Supplies & Expenses*	$380	$317	$31	$32
109	Outside Services Employed - Resid.	$84	$84	$0	$0
110	Outside Services Employed - Labor	$1,691	$1,411	$136	$144
111	Injuries & Damages	$157	$131	$13	$13
112	Employment Pensions and Benefits	$2,663	$2,222	$214	$227
113	Rents	$1,871	$1,562	$150	$159
	Admin. & General Expenses - Plant Related				
114	Property Insurance	$20	$15	$2	$3
115	Outside Services Employed - Plant	$8	$6	$1	$1
116	Injuries & Damages	$251	$189	$21	$41
117	Misc. Maintenance Expense	$74	$56	$6	$12
	Admin. & General Expenses - Other Related				
118	Admin. Expenses Transferred	($6)	($4)	($1)	($1)
119	Outside Services Employed - Plant - O&M	$1,167	$859	$108	$200
120	Regulatory Commission Expenses	$86	$63	$8	$15
121	General Advertising Expense	$34	$25	$3	$6
122	*Miscellaneous General Expenses*	$25	$19	$2	$4
	Taxes - General Taxes				
123	Local Property Taxes	$4	$3	$0	$1
124	Public Utility Realty Tax	$33	$26	$3	$5
125	*State Capital Stock Tax*	$33	$25	$3	$5
126	Total Operating & Maintenance	$12,793	$10,667	$996	$1,230
127	Depreciation expense	$3,264	$2,869	$210	$186
128	*Additional expense*	$1,103	$1,103	$0	$0
129		$58,848	$51,517	$2,640	$2,691
130	Total OnSite Customer	$65,674	$57,628	$3,610	$4,436
	Summary of Customer Costs				
131	Distribution Customer	$38,613	$34,973	$1,843	$1,797
132	OnSite Customer	$65,674	$57,628	$3,610	$4,436
	Other Revenue				
133	Forfeited Discounts	$0	$0	$0	$0
134	Miscellaneous Service Rev.	$0	$0	$0	$0
135	Other Operating Revenue	$0	$0	$0	$0
136	Total Other Revenue	$0	$0	$0	$0
137	Total Customer Component	$104,287	$92,601	$5,453	$6,232
138	Average Bills X 1000	3,084	2,871	191	22
139	Average Monthly Cost	$33.81	$32.25	$28.57	$281.78

OTS
(In $1000's)

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Balance of OnSite				
95	Return on Rate Base	$0	$0	$0	$0
96	Income Tax gross-up	$0	$0	$0	$0
97	Meter Reading	$586	$546	$36	$4
98	Customer Records and Collection	$10,271	$9,561	$636	$74
99	*Uncollectible Accounts*	$25,050	$23,515	$540	$995
	Operating & Maintenance				
	O & M Expenses - Distribution Expenses				
100	Operation Supv & Engineering	$0	$0	$0	$0
101	Customer Installation Expense	$62	$62	$0	$0
102	*Other Expenses - Safety & Environmental*	$0	$0	$0	$0
103	Other Expenses	$0	$0	$0	$0
104	Distribution Rents	$0	$0	$0	$0
105	Maintenance of Services	$663	$626	$6	$31
	Customer Accounts Expenses				
106	Customer Service - Administrative	$226	$210	$14	$2
	Admin. & General Expenses - Labor Related				
107	Administrative & General Salaries	$0	$0	$0	$0
108	Office Supplies & Expenses	$0	$0	$0	$0
109	Outside Services Employed - Resid.	$0	$0	$0	$0
110	Outside Services Employed - Labor	$0	$0	$0	$0
111	Injuries & Damages	$157	$131	$13	$13
112	Employment Pensions and Benefits	$2,663	$2,222	$214	$227
113	Rents	$0	$0	$0	$0
	Admin. & General Expenses - Plant Related				
114	Property Insurance	$0	$0	$0	$0
115	Outside Services Employed - Plant	$0	$0	$0	$0
116	Injuries & Damages	$251	$189	$21	$41
117	*Misc. Maintenance Expense*	$0	$0	$0	$0
	Admin. & General Expenses - Other Related				
118	Admin. Expenses Transferred	$0	$0	$0	$0
119	Outside Services Employed - Plant - O&M	$0	$0	$0	$0
120	*Regulatory Commission Expenses*	$0	$0	$0	$0
121	General Advertising Expense	$0	$0	$0	$0
122	Miscellaneous General Expenses	$0	$0	$0	$0
	Taxes - General Taxes				
123	*Local Property Taxes*	$0	$0	$0	$0
124	Public Utility Realty Tax	$0	$0	$0	$0
125	State Capital Stock Tax	$0	$0	$0	$0
126	Total Operating & Maintenance	$4,022	$3,439	$269	$314
127	Depreciation expense	$1,012	$832	$63	$117
128	Additional expense	$0	$0	$0	$0
129		$40,941	$37,893	$1,544	$1,504
130	Total OnSite Customer	$49,767	$44,004	$2,514	$3,249
	Summary of Customer Costs				
131	Distribution Customer	$24,042	$22,575	$403	$1,084
132	OnSite Customer	$49,767	$44,004	$2,514	$3,249
	Other Revenue				
133	Forfeited Discounts	($1,558)	($1,462)	($34)	($62)
134	Miscellaneous Service Rev.	($1,208)	($1,163)	($40)	($5)
135	*Other Operating Revenue*	($61)	($43)	($6)	($12)
136	Total Other Revenue	($2,827)	($2,668)	($80)	($79)
137	Total Customer Component	$70,982	$63,911	$2,837	$4,234
138	Average Bills X 1000	3,084	2,871	191	22
139	Average Monthly Cost	$23.02	$22.26	$14.85	$192.45

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

EQUITABLE GAS COMPANY

DOCKET NO. R-2008-2029325

11/20/08
Hurley
KJH

Direct Testimony of Debra Backer, OTS Statement No. 2
Errata Sheet

A. Page 2, table, Cash Working Capital OTS Recommended Claim delete $8,670,950; insert $8,645,944.

B. Page 2, table, Cash Working Capital, OTS adjustment delete ($2,664,385); insert ($2,689,391).

C. Page 21, line 6, delete (182); insert (162).

D. Page 21, line 7, delete ($3,089,632); insert ($2,750,112).

E. Page 21, line 8, delete $1,188,207; insert $1,527,727.

F. Page 21, line 9, delete ($2,858,492); insert ($2,544,372).

G. Page 21, line 9, delete $1,099,508; insert $1,413,628.

H. Page 21, line 10, delete $2,287,715; insert $2,941,355.

I. Page 21, line 16, delete $2,287,715; insert $2,941,355.

J. Page 21, line 18, delete ($251,543,450); insert ($248,602,095).

K. Page 21, line 21, delete (162.07); insert (160.17).

L. Page 21, line 22, delete ($251,543,450); insert ($248,602,095).

M. Page 22, line 6, delete $8,670,950; insert $8,645,944.

N. Page 22, line 6, delete $2,644,385; insert $2,689,391.

O. Page 22, line 9, delete $8,670,950; insert $8,645,944.

P. Page 23, table, Cash Working Capital OTS Recommended Claim delete $8,670,950; insert $8,645,944.

Q. Page 23, table, Cash Working Capital, OTS adjustment delete ($2,664,385); insert ($2,689,391).

EQUITABLE GAS COMPANY - per OTS
SUMMARY OF CASH WORKING CAPITAL LEAD/LAG STUDY AT PRESENT BASE RATES
TWELVE MONTHS ENDED DECEMBER 31, 2008

OTS Exhibit No. 2
Schedule 10
Corrected

Cost Category	*Pro Forma* Expense	*Daily* Requirement	Revenue *Lag* Days		Expense *Lag* Days		Net *Lag* Days	Working *Capital* Requirement
(1)	(2)	(3)	(4)		(5)		(6)=(4)-(5)	(3)*(6)
OPERATING EXPENSES								
Gas Purchased	359,315,773	984,427	47.29	(a)	45.91		1.38	1,361,425
Payroll	24,095,087	66,014	47.29		17.09		30.20	1,993,621
Employee Benefits	7,069,423	19,368	47.29		11.03		36.26	702,322
Corporate Services	15,990,000	43,808	47.29		14.71		32.58	1,427,241
Injuries & Damages Insurance	4,803,788	13,161	47.29		(160.17)	(b)	207.46	2,730,394
Uncollectibles	25,049,825	68,630	47.29		47.29		-	-
Other O & M Expense	28,100,026	76,986	47.29		36.84	(c)	10.45	804,508
Total Operating Expense	464,423,924							
Depreciation & Amortization	23,471,055							
TAXES OTHER THAN INCOME	2,185,866	5,989	47.29		(66.05)		113.3	678,736
INCOME TAXES								
Current -Federal	(3,182,873)	(8,720)	47.29		36.50		10.8	(94,091)
Current - State	(1,009,313)	(2,765)	47.29		51.58		(4.3)	11,849
Deferred - Federal & State	8,545,747							
Investment Tax Credit	(5,529)							
INTEREST ON DEBT	16,972,650	46,500	47.29		72.58		(25.3)	(1,176,131)
PA Sales and Use Taxes	6,287,006	17,225	47.29		35.33		11.96	206,070
TOTAL CASH WORKING CAPITAL REQUIREMENT								8,645,944

(a) Billing lag reduced by 2 days in OTS Statement No. 2
(b) Injuries and Damages Insurance reduced due to Equitable responses to OTS Interrogatories
(c) Other O&M expense lag updated in OTS Statement No. 2 due to Equitable responses to OTS interrogatories