BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : DOCKET NO. 000108-GU

REQUEST FOR RATE INCREASE BY FLORIDA DIVISION OF CHESAPEAKE UTILITIES CORPORATION.

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VOLUME 2

Pages 212 through 327

PROCEEDINGS: **HEARING**

BEFORE: CHAIRMAN J. TERRY DEASON
COMMISSIONER E. LEON JACOBS, JR.
COMMISSIONER LILA A. JABER

DATE: Monday, October 16, 2000

TIME: Commenced at 9:30 a.m.
Concluded at 2:15 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: KORETTA E. STANFORD, RPR
Official FPSC Reporter

I N D E X

WITNESSES

EXHIBITS

(Transcript continues in sequence from Volume 1.)

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is Cherry Tree Corporate Center, 535 Route 38 East, Suite 200, Cherry Hill, New Jersey 08002-2953. I am Managing Consultant of the firm P. Moul & Associates, Inc., an independent, financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A that follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate cost of equity and overall rate of return that the Florida Public Service Commission ("FPSC" or the "Commission") should allow the Florida Division of Chesapeake Utilities Corporation ("Florida Division" or the "Company") an opportunity to earn on its rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data set forth in Composite Exhibit No. PRM-1 which consists of 13 schedules. Additional evidence is contained in Appendix B through Appendix J which follow my direct testimony. The items covered in these appendices deal with the technical aspects of my testimony. Appendices A through J are identified as Composite Exhibit No. PRM-2.

Q. Were the foregoing exhibits prepared under your direction, supervision and control?

A. Yes.

Q. What rate of return has the Company proposed in this case?

A. The Company has requested that the Commission afford it an opportunity to earn a 9.80% overall rate of return on investor-provided capital and an 8.89% overall rate of return for ratesetting purposes. As shown on Schedule 1 of Composite Exhibit No. PRM-1, the calculation of the weighted average cost of capital, which serves as the basis of the overall rate of return, requires the selection of appropriate capital structure ratios and a determination of the appropriate cost rate for each capital component. Those ratios and cost rates will be discussed in further detail later in my direct testimony. The overall fair rate of return is the product of weighting the individual capital costs by the proportion of each respective type of capital. The resulting overall rate of return, when applied to the Company's rate base, will provide a compensatory level of return for the use of capital and provide the Company with the ability to attract capital.

Q. What background information about the Company have you considered in the preparation of your testimony?

A. The Company is a division of Chesapeake Utilities Corporation ("CUC") which is a diversified energy company that also has gas distribution operations in Delaware and Maryland. The Florida Division is a small gas distribution utility that provided service to 9,633 customers in 1999. Of these customers, 8,745 were residential, 825 were commercial, 58 were industrial, 4 were electric generators, and 1 was a sales for resale customer. The Company distributes natural gas purchased directly from producers and marketers through delivery arrangements with Florida Gas Transmission Company. Throughput on the Company's system was represented by about 21% of sales service and 79% of transportation service in 1999. Throughput on the Company's system was comprised of approximately 2% to residential customers, 5% to commercial customers, 45% to industrial customers, 46% to electric generators, and 2% to the resale customer. In my opinion, with respect to customer/sales/revenue mix, the Company is unique. I know of no other gas utility where such a small number of customers represent such a high proportion of total throughput and revenues. Indeed, the high proportion of industrial and electric generation service that dominates the Company's business indicates an unusually high risk profile for the Company.

Q. How have you determined the cost of equity for the Company?

A. My recommended cost of equity is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of equity, for a gas distribution utility, such as the Florida Division . In analyzing the Company's cost of equity, I have relied on four, well-recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. By considering the results of a variety of approaches, I determined that my analysis is consistent with the well-recognized principles for determining a fair rate of return. The models that I used to measure the cost of equity for the Company have been applied with data developed from a proxy group of seven gas distribution companies which are identified on page 2 of Schedule 3. I will refer to my seven company proxy group as the "Barometer Group" throughout my testimony.

Rather than rely upon the market-determined cost of equity for an individual company, I have employed the stock market prices for the seven company Barometer Group. While the common stock of CUC is listed and traded on the New York Stock Exchange, I have not separately measured the cost of equity for CUC on a stand-alone basis. I have taken this position because the determination of the cost of equity for an individual company has become increasingly problematic. Furthermore, the gas distribution and transmission operations of CUC represent 33% of revenues, 69% of operating income, and 70% of assets of its consolidated business. I have included CUC as a component of the Barometer Group which has allowed for continued recognition of the relevance of this market data in measuring the cost of equity for its divisions. Also, by employing group average data for the Barometer Group, rather than individual company analysis, I have minimized the effect of any anomalies in the market data for an individual company.

Q. Please summarize the basis for your cost of equity recommendation in this proceeding.

A. My recommendation is derived from the results of the four methods/models previously identified. In general, the use of more than one approach provides a superior foundation to arrive at the cost of equity. At any point in time, individual methods can provide an incomplete measure of the cost of equity depending upon extraneous factors which may influence market sentiment. The results of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity for each of these approaches.

DCF	13.14%
RP	13.07%
CAPM	14.38%
CE	11.70%
Range:	
High	14.38%
Low	11.70%
Midpoint	13.04%
Average	13.07%
Median	13.11%

Based upon these results, the cost of equity is 13.0% derived from the evidence for the Barometer Group.

As explained in the testimony of Mr. Geoffroy, the Company, however, requests that the Commission provide a 12.0% rate of return on common equity in this proceeding. This decision was made in order to accommodate the market forces that affect customer demand for the Company's service. That is to say, the Company must be sensitive to competitive forces in order to maintain and increase its market share. So while my cost of equity recommendation is 13.0% in this case, there is a limitation on the rate of return on common equity which the Company can request in order to remain an aggressive competitor in its market area. The Company has taken this position as a proactive measure to deal with the many unique factors that affect its business. Without these constraints, the Florida Division would otherwise require a higher rate of return on common equity as compensation for its above average risk and in recognition of the Company's skillful management of those risks.

Q. In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A. The Commission should consider the ratesetting principles that I have set forth in Appendix B. In this regard, the end result of the rate of return finding by the Commission must cover the Company's designated interest and dividend payments, provide a reasonable level of earnings retention (i.e., produce an adequate level of internally generated funds to meet capital requirements), be commensurate with the risk to which the Company's capital is exposed, and support reasonable credit quality. I therefore tested the Company's rate of return proposal by reference to certain well-recognized credit quality benchmarks in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. I have concluded that the Company's proposed rate of return in this case is necessary and appropriate to satisfy the capital attraction and maintenance of credit standards of a fair rate of return.

Q. What are some of the important factors that influence credit quality?

A. In this regard, the Company must have the financial strength that will, at a minimum, permit it to maintain a financial profile that is commensurate with the requirements to obtain a solid investment grade bond rating. Even though it has no credit quality standing on its own, the Florida Division must provide a positive contribution to the credit quality of CUC that does issue its debt directly to investors. A variety of quantitative and qualitative measures must be considered when determining an appropriate rate of return on common equity. In quantitative terms, two of the measures of credit quality considered by the bond rating agencies, such as Standard & Poor's Corporation ("S&P") and Moody's Investors Service, Inc. (Moody's), include debt leverage and pre-tax interest coverage. In the area of coverage, the rate of return on common equity represents a critical component because it is the equity return that provides the margin whereby an interest coverage multiple greater than one is realized.

Q. What credit quality measures are reflected in the 9.80% rate of return based upon investor-provided capital?

A. I analyzed the Company's rate of return on investor-provided capital by reference to the two benchmarks of credit quality enumerated above in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. It is important that the Commission provide the Company with a reasonable opportunity to achieve adequate credit quality so that its financial condition provides a positive contribution to CUC when it must access the public markets to obtain capital. In this regard, coverage of senior capital costs reveals the level of protection that the Florida Division can supply for its allocated proportion of fixed obligations of CUC. Interest coverage is measured on both a before- and after-income tax basis. Normally, before-income tax coverage is used to evaluate a company's debt interest coverage and overall after-income tax coverage is the measure employed with regard to payment of interest charges and preferred stock dividends.

Interest coverage is not the only factor to be considered in testing the appropriate rate of return, but instead must be viewed in relation to an individual company's degree of financial leverage and cash flow benchmarks. Maintenance of a strong A bond rating financial profile is the appropriate regulatory objective and achievement of an AA bond rating should be encouraged. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Customers also benefit from strong credit quality because the utility will be able to obtain lower financing costs that are passed on to customers in the form of a lower embedded cost of debt. The Commission should encourage higher levels of interest coverage in an increasingly competitive utility industry with the need to attract capital in the future.

Using a 35.00% federal income tax rate, Schedule 1 shows that the pre-tax coverage of interest expense would be 4.13 times assuming the Company could actually realize a 9.80% overall rate of return. The 4.13 times pre-tax interest coverage and 45.23% combined debt leverage shown on Schedule 1 should be viewed in the context of the S&P bond rating criteria that I will subsequently discuss. It is important to recognize that the benchmarks represent levels expected to be achieved, rather than the opportunity provided by the rate of return used in the ratesetting process. It is my opinion that the Company should be provided with an opportunity to attain the credit quality profile reflected on Schedule 1.

NATURAL GAS RISK FACTORS

Q. Please identify some of the factors that make the natural gas industry different today from its past.

A. Gas supply fundamentals have changed significantly as a result of the implementation of FERC Order Nos. 436, 500, and 636 which restructured the pipeline industry, and hence, gas supply fundamentals for natural gas distribution utilities, such as the Florida Division . The sweeping changes that have occurred through implementation of Order No. 636 have, among other things: eliminated the pipeline merchant function;

completely unbundled the supply, transportation and storage functions provided by the interstate pipelines; fostered a pipeline rate design (i.e., straight fixed-variable, "SFV") that has decoupled revenues associated with the recovery of fixed costs from throughput, and required pipeline capacity reassignment. Further, implementation of "SFV" rate design has increased monthly demand charges payable to the interstate pipelines which have increased rates to low load-factor customers, such as residential customers. For a gas distribution utility, FERC Order No. 636 has moved the focus of gas supply from the city gate to the production field.

Q. Will gas transportation service be expanded to cover a larger proportion of the Company's customers?

A. Yes. The FPSC recently adopted Rule 25-7.0335, F. A. C., effective April 23, 2000, which requires each local distribution company to offer the transportation of natural gas to all non-residential customers. In order to meet that objective, each gas utility must file a transportation service tariff with the FPSC by July 1, 2000. The Company's proposal to implement the new rule is filed as a part of this rate case. The Company's current eligibility threshold for transportation service is 200,000 therms annually. Under the Company's proposal, the annual threshold would be lowered to 100,000 therms, and small volume customers would be permitted to aggregate their annual requirements under certain terms and conditions to meet the lower threshold. Once approved and implemented, the proportion of the Company's throughput represented by transportation service will undoubtedly increase from its current level.

Q. How have all these changes affected the natural gas utilities?

A. The new competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements now taking place mean that natural gas utilities will be operating in a more complex environment with time frames for decision-making considerably shortened. As the competitiveness of the natural gas business increases, the risk also increases. Natural gas continues to face significant competition from alternative energy sources. In its service territory, the Company faces competition from fuel oil, propane, and electricity in its markets. Moreover, the changes fostered by Order 636 have promoted competition among and between pipelines and distributors. Risk will continue to rise as large end users seek to obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Moreover, with the ongoing restructuring of the electric utility business, energy will be marketed increasingly on a BTU basis regardless of its form, further heightening the competitive pressure on the natural gas business. With increased interfuel competition and energy interchangeability, risk will continue to increase for gas companies during and after the restructuring of the electric utility business. Regulatory initiatives deregulating the price of power mean that retail electricity prices will be much more flexible than had been the case in the past. Moreover, heightened competition will undoubtedly develop from consolidation within the utility industry because mergers can result in lower costs for the survivors which will allow them to become more aggressive competitors.

Q. How have the bond rating agencies viewed the business risk facing the gas utilities?

A. S&P has established a risk-adjusted or matrix approach to the financial benchmarks used to assess the credit quality of all regulated public utilities, including the gas distribution companies. For some time, S&P has applied a matrix approach which adjusts its financial benchmarks according to each company's business risk profile. That is to say, more lenient criteria are applied to companies with lower business risk, whereas more stringent criteria are applied to companies with higher business risk. In this regard, S&P has categorized each gas distribution company according to an assessment of its business risk. This risk evaluation has been expressed by business profile assignments that are intended to represent a specific level of business risk. Each regulated firm is assigned to a category on a scale of 1 (strong) to 10 (weak). In assigning a business profile, S&P has enumerated the key items it considers: Regulation, Markets, Operations, Competitiveness, and Management.

According to S&P, at year-end 1998, the general breakdown of the gas distribution companies was:

Business Profile	Number of Gas Distribution Companies	Percent of Industry
2	11	28%
3	16	40%
4	13	32%
	40	100%

The average business profile for the gas distribution industry is "3." The average business profile assigned by S&P to the Barometer Group is also "3," as shown on page 2 of Schedule 3.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. As described in the testimony of Mr. Geoffroy, the Company has invested in the past and will continue to invest in new facilities to meet growth and to maintain and enhance the efficiency and reliability of existing facilities. To maintain safe and reliable service to customers, the Company must invest to upgrade its existing infrastructure. In the situation where additional capital is required, especially for non-revenue producing infrastructure rehabilitation, the regulatory process must provide a reasonable opportunity for the Company to actually achieve its cost of capital. For the next five year period, the Company's capital expenditures are estimated to be:

Year	Amount
2000	$ 4,197,189
2001	3,087,446
2002	3,718,331
2003	3,646,525
2004	3,714,094
Total	$18,363,585

For the years 2000 to 2004, future construction expenditures will represent a significant 65% ($18,363,585 ÷ $28,304,760) increase in the balance of gross gas plant and CWIP at December 31, 1999 . This large commitment of capital by the Florida Division substantially exceeds its internally generated funds represented by approximately $1.2 million annually of depreciation expense and approximately $0.4

million annually of deferred income taxes. In the situation where additional capital investment is required, the regulatory process must provide an opportunity for the Company to realize a fair rate of return, so as to attract capital on reasonable terms.

Q. What are some of the other factors that influence the Company's risk profile?

A. There are a number of factors that differentiate the Florida Division, and the region in which it operates, from purveyors of gas distribution service operating in other regions of the U.S. For a number of these factors, they point toward a higher risk profile for the Company as compared to most other gas utilities. These factors are:

- The Florida Division is an extremely small enterprise having a very small number of customers.
- In Florida, there are no pre-defined service territories, thereby providing both opportunities and obstacles for expansion.
- The threat of bypass is extremely high for the Company because its throughput profile is dominated by a small number of large volume users that are situated relatively close to Florida Gas Transmission.
- The Company has a single interstate pipeline supplier that reduces its flexibility to obtain alternative transmission service.
- There are two new gas transmission projects proposed for Florida (i.e., Gulfstream and Buccaneer) either of which would provide diversification for the delivery of new gas supplies and would also increase the threat of bypass of the Company's system.
- The Company's load profile is heavily influence by the requirements of

customers engaged in three industries: phosphate, citrus, and electric generation.

- The Company has had to provide special contract terms to two large volume customers in order to retain their load on the Company's system.
- The Company is faced with strict regulatory oversight that continuously monitors for "excess" earnings.
- The Company faces environment issues associated with the investigation of possible contamination at the former manufactured gas facility in Winter Haven.

Given the risk factors that I have described for the Company, its business risk is at the high end of the risk spectrum for the gas distribution industry.

Q. Of the items that you enumerated above, what are some of the key issues that affect the Company's ability to retain load on its system?

A. The key issues that influence the Company's ability to retain load on its system include: (i) the dominant role represented by the phosphate and citrus industries, (ii) the proposed construction of additional interstate transmission facilities that will bring new supply to the Florida gas markets, and (iii) the special contracts with large volume, electric generators.

Q. How do the phosphate and citrus industries impact the Company's risk profile?

A. As noted previously, industrial customers represent a significant 45% of the throughput on the Company's system, yet number only 1% of its customers. The Company's phosphate customers operate in a cyclical industry that is subject to intense global competition. These customers also represent a potential bypass threat to the Company's facilities. As to the citrus industry, throughput to these customers is affected by seasonal demand, alternative fuels, weather conditions, agricultural disease and pests, and domestic and global competition. Aside from the obvious threats from weather and agricultural disease and pests, the citrus industry is faced with significant global competition, especially by production from Brazil.

External factors such as these can impact the Company's throughput to these customers due to competitive pressures that arise from outside the Company's service territory. The consequences of these forces can result in plant closures or relocations, over which the Company has no control. In the area of energy costs, the Company has responded with innovative tariff provisions, such as flexible rates, to address some of the competitive issues faced by these industries.

Q. How will the construction of new interstate transmission facilities impact the Company's business?

A. Construction of either the Gulfstream or Buccaneer pipelines will provide the Company with alternative transportation service which will serve to stimulate competition in the supply side of the Company's business. New pipeline capacity that would become available if Gulfstream were constructed would significantly increase the bypass opportunities for the Company's customers due to its proposed route. Bypass represents the single most important threat to the Company's business. To date, the Company has been successful defending its position by offering special contracts to its two largest customers in order to retain their load on its system. Aside from the stranded cost issue associated with abandoned facilities that would occur in a bypass situation, capacity contracted by the Company on the interstate pipeline system represents another risk issue if bypass were to occur.

Q. You have noted that the Company has entered into special contracts in order to retain customers on its system. Are these arrangements vulnerable in the future?

A. Yes. Special contracts have been negotiated with three of the four electric generation customers. Customers that use gas for electric generation are potential targets of bypass. With the new transmission projects proposed for the Florida market, special contract customers may well avoid extending these arrangements for lengthy periods of time in order to retain the greatest degree of supply flexibility. Hence, for the four customers that represent 46% of throughput on the Company's system, there is significant exposure for the Company when only a few customers represent such a large percentage of throughput.

Q. Has the Company been able to manage these risk?

A. As noted above, the Company has skillfully managed the risks associated with serving a market represented by a small number of high volume customers. In this regard, the Company has implemented innovative programs to retain load on its system. The Commission should recognize this accomplishment in the face of a high risk profile for the Florida Division.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I have compared the Florida Division to the S&P Public Utilities, an industry-wide proxy consisting of various public utility endeavors, and the Barometer Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely-recognized index which at year end 1998 was comprised of twenty-eight electric power companies and eleven natural gas companies. These companies are identified on pages 3 and 4 of Schedule 4. I have used this group as a broad-based measure of regulated public utility endeavors.

Q. What criteria have you employed to assemble your Barometer Group?

A. The Barometer Group I have employed in this case includes companies that are engaged in similar business lines and have marketable securities. The Barometer Group companies have the following common characteristics: (i) they are contained in Edition 3 of <u>The Value Line Investment Survey</u> Natural Gas Distribution basic service or its Expanded Edition, (ii) they have operations in Southeastern and South Central regions of the U.S. based upon the grouping of states by the Federal Energy Regulatory Commission, and (iii) they are not currently the target of a merger or acquisition. By limiting the selection of companies to these regions, I have applied a geographic screening criteria to the companies in the Barometer Group. Due to the acquisition premiums associated with takeover targets, I have eliminated one company (i.e., Public Service of North Carolina) that would otherwise qualify for my Barometer Group because its valuation is substantially influenced by an acquisition premium.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for CUC, the Barometer Group, and the S&P Public Utilities?

A. A public utility must have the financial strength to support its credit standing in order to fulfill its public service responsibilities. In this regard, the Florida Division must make a positive contribution toward CUC's financial condition in order to support the credit quality that is equivalent to the investment grade ratings employed in the private placement market as established by the designations of the National Association of Insurance Commissioners ("NAIC"). The long-term debt of CUC carries a designation of "1" from the NAIC which would be equivalent to all of the A ratings by Standard & Poor's Corporation ("S&P") and Moody's Investors Service ("Moody's") -- both nationally recognized credit rating agencies. Presently, the corporate credit rating ("CCR") for the Barometer Group is an average A- from S&P and an average A3 from Moody's. The CCR is a designation by S&P that focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is A by S&P and A2 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. What factors influence the bond ratings assigned by the credit rating agencies?

A. The credit rating agencies consider various qualitative and quantitative factors in assigning grades of creditworthiness. On June 21, 1999, S&P modified its benchmark criteria with a focus on the relative business risk of a firm regardless of its industry-type. These benchmarks replaced former criteria that were directed toward specific types of utilities. Now, each gas distribution company will be measured against a uniform set of financial benchmarks applicable to all firms that are assigned to a specific business profile. S&P has indicated that no rating changes should be expected from the new financial targets because they were developed by integrating prior financial benchmarks and historical industrial medians. The financial benchmarks for a utility with a "4" business profile include:

Rating	Pre-Tax Interest Coverage	Debt Leverage	Funds from Operations Interest Coverage	Funds from Operations to Total Debt
AA	4.6-4.0×	37.5-43.0%	5.1-4.5×	36.5-30.5%
A	4.0-3.3	43.0-49.5	4.5-3.8	30.5-24.5
BBB	3.3-2.2	49.5-57.0	3.8-2.7	24.5-17.5
BB	2.2-1.3	57.0-64.0	2.7-1.8	17.5-12.0
B	1.3-0.5	64.0-72.5	1.8-0.9	12.0-6.0

Q. How do the financial data compare for the Florida Division , the Barometer Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and Schedule 4. I have employed the FPSC Annual Report financial data for my analysis of the Company. I have modified the Annual Report data for the Florida Division by allocating to it a portion of the annual dividend payments by CUC. Since, the Florida Division receives an allocation of interest expenses from CUC, I have assigned a similar percentage of the CUC dividend to the Florida Division. I will highlight the important categories of relative risk as follows:

<u>Size</u>. In terms of capitalization, the Florida Division is very much smaller than the average size of the Barometer Group. The S&P Public Utilities are many times larger than the Florida Division and the Barometer Group. All other things being equal, a smaller company is riskier than a larger company, since a given change in revenue and expense has a proportionately greater impact on a small firm. Small firms can also encounter reduced liquidity for their securities which can add to risk and increase capital costs. As I will demonstrate later, the size of a firm can significantly

influence its cost of equity for the Barometer Group.

Market Ratios. Historical market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk as compensation for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings; a high earnings/price ratio is thus indicative of greater risk.[1]

Since the Company is a division of CUC, there are no market ratios available for the Florida Division. The average earnings/price ratios were higher for the Barometer Group than the S&P Public Utilities. The average dividend yields were fairly similar for the Barometer Group and the S&P Public Utilities. Likewise, the historical market-to-book ratios were also fairly similar for the Barometer Group and the S&P Public Utilities. I will subsequently discuss the cost of equity implications of the market-to-book ratios.

Common Equity Ratio. The level of financial risk is measured by the proportion of debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has low financial risk, while a firm with a low common

[1] For example, two otherwise similarly situated firms each reporting $1.00 earnings per share would have different market prices at varying levels of risk, i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value.

equity ratio has high financial risk. No investor-provided capital is assigned to the Florida Division by CUC. Rather, the Company's capitalization is represented by its retained earnings account. As such, capital structure comparisons are not meaningful for the Florida Division. The five-year average common equity ratio, based on permanent capital was 49.5% for the Barometer Group and 45.9% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. For the five year period, the coefficients of variation were 0.226 (1.9% ÷ 8.4%) for the Florida Division, 0.100 (1.2% ÷ 12.0%) for the Barometer Group, and 0.152 (1.6% ÷ 10.5%) for the S&P Public Utilities. The higher coefficient of variation for the Florida Division signifies higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income)[2]. The five-year average operating ratios were 89.9% for the Florida Division, 87.6% for the Barometer Group, and 80.5% for the S&P Public Utilities. The higher operating ratio for the Florida Division again signifies higher risk for the Company.

Coverage. The level of fixed charge coverage (i.e., the multiple by which

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

available earnings cover fixed charges, such as interest expense and preferred stock dividends) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 3.3 times for the Florida Division, 3.0 times for the Barometer Group, and 3.3 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, relative amounts of deferred costs, and the effective income tax rate. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Florida Division, the Barometer Group, and the S&P Utilities in recent years.

Internally Generated Funds. Historically, the five-year 1994-1998 average percentage of internally generated funds ("IGF") to capital expenditures was 85.0% for the Florida Division, 66.9% for the Barometer Group, and 125.9% for the S&P Public Utilities. The percentage of IGF to construction for the Florida Division and the Barometer Group has lagged behind that of S&P Public Utilities.

Betas. The financial data I have been discussing relate primarily to company-specific risks. Market risk for firms with traded stock is measured by beta coefficients, which attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Merrill Lynch publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[3] A comparison of market risk is shown by the betas provided on page 2 of Schedule 3 -- .50 for the Barometer Group and page 4 of Schedule 4 -- .56 average beta for the S&P Public Utilities and .52 for the S&P Public Utilities Index which is market weighted. Keeping in mind that the gas industry has changed significantly during the past several years, the systematic risk percentage was 89% (.50 ÷ .56) for the Barometer Group using the S&P Public Utilities' average beta as a benchmark. Alternatively, the systematic risk percentage for the Barometer Group was 96% (.50 ÷ .52) using the beta of the S&P Public Utilities Index.

Q. Please summarize your risk evaluation of the Company and the Barometer Group.

A. In my opinion, the Barometer Group provides a reasonable proxy to measure the cost of equity for the Florida Division. In certain respects, the Company has higher risk traits as shown by its much smaller size and more variable returns. Overall the Barometer Group provides a reasonable basis to measure the Company's market determined cost of equity.

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3 The Merrill Lynch beta coefficient is derived from a straight regression based upon the percentage change in the price of an individual common stock and percentage change in the S&P Composite Index using monthly data over a five-year period. The raw historic beta is adjusted by Merrill Lynch for the measurement effect resulting in underestimates of low beta stocks and overestimates of high beta stocks. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk. Merrill Lynch also provides the coefficient of determination (R^2) which indicates the percent of price fluctuation in the stock which can be attributed to the fluctuation in the S&P Composite Index. Since the coefficients of determination are low (i.e., .03 for the Barometer Group, and .05 as the average for the S&P Public Utilities), it is apparent that the vast majority of the investment risk is unsystematic and hence not explained by the beta.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for the Florida Division .

A. In the situation where the operating public utility raises its own debt directly in the capital markets, it is usually the practice to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility form the basis of the capital employed and the capital cost rates are directly identifiable.

As previously noted, the Company has no separate capital structure because it relies upon CUC for all its external capital needs. As such, the capitalization of CUC represents the basis for the capital structure ratios for ratesetting purposes. Since the minimum filing requirements do not recognize cost-free capital as a rate base deduction, those amounts are included in the rate of return calculation. The capital structure ratios for the future test year 2001 are shown on page 1 of Schedule 5. These ratios were taken from Schedule G-3 of the minimum filing requirements.

Q. What capital structure ratios do you propose for the Company in this case?

A. My proposal is that the Company should use capital structure ratios that include 33.95% long-term debt, 11.28% short-term debt and 54.77% common equity when considering investor-provided capital alone. These capital structure ratios conform with the ratios expected by investors for a small gas distribution utility and are reasonable for this case. In further support of these capital structure ratios, the credit rating agencies expect that a utility having a "4" business profile will employ 43.0% to 49.5% debt for an A rating. The combined debt ratio of 45.23% (33.95% + 11.28%)

is within this range. Therefore, the capital structure ratios proposed for the Florida Division in this case are reasonable because they conform with a reasonable level of credit quality.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the long-term debt portion of the Florida Division 's capital structure?

A. The determination of the cost of debt is essentially an arithmetic exercise. This is due to the fact that a Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 2 of Schedule 5, the embedded cost rate of long-term debt is estimated to be 7.52% for the rate year 2001.

COST OF EQUITY DETERMINATION

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among the Florida Division, the Barometer Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity. It is also important to reiterate that no one method or model for determining the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from all methods that I have considered. In this regard, I have applied each of these methods with data taken from the Barometer Group and have arrived at a cost of equity of 13.0%.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The cost of equity based on a combination of these two components represents the total return that investors can expect with regard to an equity investment.

Among other limitations of the model, there is a certain element of circularity in the DCF when applied in public utility rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations which include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix E, the DCF approach has certain limitations which diminish its usefulness when stock prices diverge significantly from book values in the ratesetting process. When stock prices diverge from book values by a significant margin, the DCF method will lead to a misspecified cost of equity. If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to a net original cost (book value) rate base, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value. That is to say, such distortions tend to produce DCF results that understate the cost of equity to regulated firms when using a book value rate base. As I will explain later in my testimony, in at least one respect, the DCF model can be modified to account for differences in risk attributed to changes in financial leverage when market prices and book values diverge.

Q. Please explain the dividend yield component of the DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended February 2000, the monthly dividend yields for the Barometer Group are shown graphically on Schedule 6. The monthly dividend yields shown on Schedule 6 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ended February 2000, the average dividend yield was 4.79% for the Barometer Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 4.96% and 5.16%, respectively, for the Barometer Group. I have used, for the purpose of my direct testimony, a dividend yield of 4.96% for the Barometer Group which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model which must reflect investor anticipated future cash flows. For the Barometer Group, I have adjusted the 4.96% dividend yield in three different but generally acceptable manners, and used the average of the three adjusted values of 5.15% as calculated in Appendix E.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Historical performance and analysts' forecasts support my opinion of the growth expected by investors. Although some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their current dividend yield requirements. Some regulatory agencies have acknowledged that a blended approach, which recognizes the preceding factors, is required in the selection of the DCF growth rate. I have followed an approach that is not rigidly formatted, because investors do not behave in such a manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques should be evaluated when formulating a judgment of investor expected growth.

Q. What data have you considered in your growth rate analysis?

A. The bar graph provided on Schedule 7 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Barometer Group. Value Line serves primarily as the source of the historical growth rates shown on Schedule 7. These growth rates have been supplemented with historical earnings per share growth published by Zacks. Zacks only publishes historical earnings per share growth rates. As shown on page 1 of Schedule 7, the historical earnings per share growth rates were in the range of 1.85% to 6.86% for the Barometer Group. The historical growth rates in earnings per share contain instances of negative values for individual companies within the Barometer Group. Obviously, negative growth rates provide no reliable guide to gauge investor expected growth for the future. Investor expectations always encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite investors' growth expectation for the future. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers, and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Because, in the long-run, investors will always expect positive growth, negative values will not provide a reasonable representation of future growth expectations. This is because, although investors have knowledge that negative growth and losses can occur, their expectations always include positive growth. Rational investors always expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 8 shows both long-run and short-run earnings per share growth rates taken from the forecasts provided in the I/B/E/S, Zacks, and Value Line publications. The I/B/E/S and Zacks forecasts are restricted to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on page 1 of Schedule 8.

Although long-run forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provide earnings forecasts for the current and subsequent year. As reported on page 2 of Schedule 8, these short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. The short-term earnings forecasts indicate double digit growth rates for the Barometer Group. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

As to five-year forecast growth rates, page 1 of Schedule 8 indicates that the projected earnings per share growth rates for the Barometer Group are 7.00% by IBES, 6.99% by Zacks, and 9.30% by Value Line. The Value Line projections indicate that earnings per share will grow prospectively at a more rapid rate (i.e., 9.30%) than dividends per share (i.e., 4.50%) which suggests a declining payout ratio in the future. With no expected change in price-earnings multiple, the value of a firm's equity (i.e., its stock price) will grow at the same rate as earnings per share, thus producing a capital gains yield to investors at the higher earnings per share growth rate.

Q. What conclusion have you drawn from these data?

A. As explained in Appendix E, historical performance and published forecasts support my opinion that a company-specific growth rate of 7.00% is indicated for the Barometer Group. While the DCF growth rate cannot be established solely with a mathematical formulation, the prospective growth rate for the Barometer Group is within the array of growth rates shown by earnings per share, dividends per share, book value per share, retention growth, and cash flow per share. Due to restructuring and consolidation now taking place in the utility industry, and as the utility industry successfully adapts to the new business environment, additional opportunities (both regulated and non-regulated) will develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects of the Barometer Group. Moreover, expectations concerning merger and acquisition ("M&A") activities also impact stock prices. M&A premiums have the effect of raising prices, and therefore reducing observed dividend yields, without necessarily showing up in higher long-term growth rate forecasts. In that case, the traditional DCF calculation would understate the required cost of equity. This is a further reason why a simple DCF rate of return requires adjustment. For the gas distribution industry, M&A activity has elevated stock prices based upon investors' expectations of enhanced market returns that arise from those combinations. M&A premiums embedded in stock prices usually result in a disconnection of those prices from the analysts' growth forecasts.

In addition, market-wide factors also influence the capital gains expected by investors. As previously indicated, there are a wide variety of factors that influence investor expected returns which are not linked specifically to company-specific performance. In an article in Standard & Poor's The Outlook (February 21, 1996), the relative valuation of common stocks was explained in part by qualitative factors (i.e., favorable psychology). Those factors which influence investor-expected growth include overall business conditions, monetary policy, fiscal and tax policy, the value of the dollar in foreign trade, and the balance of trade, all of which I would categorize, at least from an investors' perspective, as qualitative influences on investors' total return expectations. In addition, investors make independent valuation assessments based upon market sentiment that includes relative P/Es, dividend yields, interest rates, the supply of stocks, etc. The combination of both quantitative factors, as shown by company-specific variables, and qualitative factors, as shown by general investor sentiment, together form the foundation for the capital appreciation (i.e., capital gains yield) that investors expect from owning a common stock.

Q. At this point, what is the sum of the dividend yield and growth rate?

A. Although this summation would not provide a complete representation of the cost of equity, the dividend yield and growth rate would provide a combined 12.15% (5.15% + 7.00%) return for the Barometer Group.

Q. In the development of the rate of return on common equity in the ratesetting context, should another component be included in the DCF model of the cost of equity?

A. Yes. As noted previously and as demonstrated in Appendix E, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to a utility's common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most gas distribution utilities. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Barometer Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for each company and the market value of the common equity using the market price of stock at year-end 1999. The comparison of capital structure ratios are:

Barometer Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	39.07%	48.98%
Preferred Stock	0.93	1.14
Common Equity	60.00	49.88
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

Q. What are the implications of the capital structure ratios measured with the market value of the Barometer Group's securities as compared to the book value of the capitalization?

A. The capital structure ratios of the Barometer Group measured at their book value show more financial leverage, and hence higher risk, than the capitalization measured at their market values. This means that a market derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization of the Barometer Group. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost equity for the Barometer Group that is related to the 49.88% common equity ratio using book value has much higher financial risk than the 60.00% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure.

Q. How can the Modigliani and Miller theory be applied to calculate the rate of return on book common equity using the market derived cost of equity as a starting point?

A. It is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

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

$$10.79\% = 12.15\% - (((10.79\% - 7.74\%)\ .65)\ 39.07\%/60.00\%) - (10.79\% - 6.68\%)\ 0.93\%/60.00\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt[4], d = dividend rate on preferred stock [5], D = debt ratio, P = preferred

[4] The cost of debt is the twelve month average yield on Moody's A rated public utility bonds.

[5] The cost of preferred is the twelve month average yield on Moody's "a" rated preferred stock.

stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 10.79% using the market value of the Barometer Group's capitalization.

Having determined that the cost of equity is ~~10.81%~~ 10.79% for a firm with 100% equity, I then calculated the rate of return on common equity using the book value capital structure. This provides:

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

$$12.82\% = 10.79\% + (((10.79\% - 7.74\%).65)48.98\%/49.88\%) + (10.79\% - 6.68\%)\ 1.14\%/49.88\%$$

Hence the Modigliani and Miller theory shows that the cost of equity increases by 0.67% (12.82% - 12.15%) when the common equity ratio declines from 60.00% using the market value of equity to 49.88% using the book value of equity.

Q. What is the sum of the dividend yield, growth rate and leverage adjustment for the Barometer Group?

A. Again, while not completely representing the cost of equity, the sum of the dividend yield, growth rate, and leverage adjustment would provide a ~~12.86%~~ 12.82% (5.15% + 7.00% + 0.67%) rate of return on equity.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As previously explained, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("*g*") previously developed. The DCF also includes the leverage modification ("*lev.*") to recognize that the book value equity ratio is used in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot."). Therefore, a flotation cost adjustment must be applied to the DCF result (i.e., "*k*") which provides an additional increment to the rate of return on equity (i.e., "*K*"). The factor used to develop the modification which would account for the flotation cost adjustment is provided in Schedule 9 and Appendix F. Even in the situation where no new stock was to be issued, failure to recognize a flotation cost adjustment would not give a utility a realistic opportunity to earn the return required by investors. The resulting DCF cost rate is:

$$D_1/P_0 \quad + \quad g \quad + \quad lev. \quad = \quad k \quad \times \quad flot. \quad = \quad K$$

$$5.15\% \quad + 7.00\% \quad + \quad 0.67\% \quad = 12.82\% \quad \times \quad 1.025 \quad = 13.14\%$$

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.32% (13.14% - 12.82%) to the rate of return on common equity for the Barometer Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown above represents the simplified (i.e., Gordon) form of the model which contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiples. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix H. I will summarize them here. With this method, the cost of equity capital is determined by reference to corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, an 8.00% yield represents a reasonable estimate of the prospective long-term debt cost rate for a public utility with an A bond rating. As I will subsequently discuss, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 10. For the twelve months ended February 2000, the average monthly yield on Moody's A rated index of public utility bonds was 7.83%. As described in Appendix G, there was generally an upward trend in public utility bond yields throughout this period.

I have determined the forecast yields on A rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in yields that I describe in Appendix G. The Blue Chip Financial Forecasts is published monthly and contains consensus forecasts of a variety of interest rates compiled from a panel of 45 banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A rated public utility bonds because the Fed deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A rated public utility bonds, I have combined the forecast yields on thirty-year Treasury bonds published on March 1, 2000 and the yield spread of 1.75% that I describe in Appendix G. These spreads can be traced to a general aversion to risk, as well as the perceived scarcity of long-term treasury obligations and an unusually shaped yield curve for Treasury issues. For comparative purposes, I have also shown the Blue Chip Financial Forecasts of Aaa rated and Baa rated corporate bonds. These forecasts are:

	Blue Chip Financial Forecasts				
	Corporate bonds		30-Year	A-rated Utility	
Quarter	Aaa rated	Baa rated	Treasury	Spread	Yield
1st Qtr. 2000	7.7%	8.4%	6.4%	1.75%	8.15%
2nd Qtr. 2000	7.7	8.4	6.4	1.75	8.15
3rd Qtr. 2000	7.7	8.5	6.4	1.75	8.15
4th Qtr. 2000	7.6	8.4	6.3	1.75	8.05
1st Qtr. 2001	7.6	8.3	6.3	1.75	8.05
2nd Qtr. 2001	7.6	8.3	6.2	1.75	7.95

Given these forecasts and the historical long-term interest rates, an 8.00% yield on A rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix H provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. It should be recognized that the S&P Public Utility index is a subset of the overall S&P 500

Composite index. The S&P Public Utility index is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Barometer Group. The S&P Public Utility index contains companies that are more closely aligned with the gas distribution industry than some broader market indexes, such as the S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of subjective judgment in establishing the risk premium for gas utilities.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values indicated on page 2 of Schedule 11, the indicated risk premiums for the various time periods analyzed are 5.23% (1928-1999), 6.08% (1952-1999), 5.23% (1974-1999), and 5.31% (1979-1999). The selection of the shorter periods from the entire historical series is designed to provide a risk premium that conforms more nearly with present investment fundamentals and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 11 represents the most recent calendar year of data which is available at the time this testimony was prepared. Hence, all historical periods include data through 1999. Second, the selection of the initial year of each period was based upon the events that I describe in Appendix H. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. As such, additional data is merely added to the earlier results when it becomes available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 11, the 1928-1999 and 1974-1999 period provide the lowest indicated risk premium, while the 1952-1999 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.27% (5.23% + 5.31% = 10.54% ÷ 2) is shown from the data covering the periods 1974-1999 and 1979-1999 which represents the more recent results. Therefore, 5.27% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Barometer Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Barometer Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 4.75% represents a reasonable common equity risk premium for this case. This represents approximately 90% (4.75% ÷ 5.27% = .90) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Barometer Group compared with that of the S&P Public Utilities.

Q. **What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?**

A. The cost of equity (i.e., "*k*") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "*i*") and the equity risk premium (i.e., "*RP*"). To that cost must be added an adjustment for common stock financing costs ("*flot.*"). As developed earlier in my DCF analysis, the flotation cost adjustment factor provided a 0.32% increment to the cost of equity for the Barometer Group. After adjusting for this factor, the Risk Premium approach provides a cost of equity of:

$$i \quad + \quad RP \quad = \quad k \quad + \quad flot. \quad = \quad K$$

$$8.00\% \quad + \quad 4.75\% \quad = \quad 12.75\% \quad + \quad 0.32\% \quad = \quad 13.07\%$$

CAPITAL ASSET PRICING MODEL

Q. **How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?**

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions, as I discuss in Appendix I. Therefore, this method should be used with other methods to measure the cost of equity as each will complement the other and will provide a result which will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM contains a yield on a risk-free interest bearing obligation plus a return representing a premium which is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix I. To compute the cost of equity with the CAPM, three components are necessary, i.e., a risk-free rate of return ("*Rf*"), the beta measure of systematic risk ("β"), and the market risk premium ("*Rm* - *Rf*") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM, it is necessary to employ firms with traded stocks. In this regard, I have performed a CAPM calculation for the Barometer Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, my Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds. Due to the disconnection of the yields on corporate and Treasury bonds, the Risk Premium approach is preferable at this time.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered an average of the Merrill Lynch and Value Line betas. As shown on page 1 of Schedule 12, the average beta is 0.55 for the Barometer Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, the Merrill Lynch and Value Line betas cannot be used directly in the CAPM unless those betas are applied to capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the average of the Merrill Lynch and Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

$$\beta l = \beta u \, [1 + (1 - t)\, D/E + P/E]$$

where l = the leveraged beta, u = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The average of the betas published by Merrill Lynch and Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization that contains a 60.00% common equity ratio. By using the formula shown above and the capital structure ratios measured at their market values, the beta would become .38 for the Barometer Group if it employed no leverage and was 100% equity financed. With the unleveraged beta, as a base, I calculated the leveraged beta of .63 for the Barometer Group associated with book value capital structure. Hence, the increase in the betas is .08 (.63 - .55) for the Barometer Group when its common equity ratio is lowered from 60.00% to 49.88%.

The betas and their corresponding common equity ratios are:

	Market Values		Book Values	
	Beta	Common Equity Ratio	Beta	Common Equity Ratio
Barometer Group	.55	60.00%	.63	49.88%

The leveraged beta that I will employ in the CAPM cost of equity is .63 for the Barometer Group.

Q. What risk-free rate have you used in the traditional CAPM?

A. For reasons explained in Appendix G, I have employed the yields on long-term 30-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on page 2 of Schedule 12, I have provided the historical yields on 30-year Treasury bonds. For the twelve months ended February 2000, the average yield was 6.06% as shown on page 3 of Schedule 12. For the six months ended February 2000, the yield on 30-year Treasury bonds was 6.28%. As shown on page 4 of Schedule 12, forecasts published by Blue Chip Financial Forecasts on March 1, 2000 indicate that the yields on 30-year Treasury Bonds are expected to be in the range of 6.2% to 6.4% during the next six quarters. To conform with the use of historical and forecast data that I employ in my analysis, I have used a 6.25% yield for Treasury bonds

Q. What market premium have you used in the traditional CAPM?

A. As developed in Appendix I, my calculation of the market premium is developed from both historical market performance (i.e., 7.8%) and with the Value Line forecasts (i.e., 14.32%). The resulting market premium is 11.06% (7.8% + 14.32% = 22.12% ÷ 2) which represents the average market premium using the historical SBBI data and the forecasts by Value Line.

Q. What CAPM result have you determined using the traditional CAPM?

A. Using the 6.25% risk-free rate of return, the leverage adjusted beta of .63 for the Barometer Group, and the 11.06% market premium, the following result is indicated after adjustment for flotation costs described previously.

$$Rf \quad + \quad \beta \quad (Rm\text{-}Rf) \quad = \quad k \quad + \quad flot. \quad = \quad K$$

$$6.25\% \quad + \quad .63 \quad (11.06\%) \quad = \quad 13.22\% \quad + \quad 0.32\% \quad = \quad 13.54\%$$

Q. What rate of return is indicated from the CAPM?

A. The CAPM result is 13.54% for the Barometer Group. I should note that there will be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk, and hence its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. This was further demonstrated in the SBBI Yearbook which indicated that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Barometer Group had an average market capitalization of its equity of $511 million which would place it in the seventh decile according to the size of the companies traded on the New York Stock Exchange. Therefore, the Barometer Group must be viewed as a portfolio of low-cap companies consisting of those in the 6th through 8th deciles with market capitalization between $215 million and $872 million. This would indicate a size premium of 0.84% above the CAPM cost rate for the low-cap companies according to the SBBI 2000 Yearbook. Absent such an adjustment, the CAPM would understate the required return unless the average size of the Barometer Group is considered. The CAPM results would be 14.38% (13.54% + 0.84%) with the size adjustment for the Barometer Group.

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The details of my Comparable Earnings approach and the evidence in support of my conclusion are set forth in Appendix J. To implement the Comparable Earnings approach, I have used both historical realized returns and forecast returns for non-utility companies. I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the

Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient[6] to cover an average business cycle. The results of the Comparable Earnings method can be applied directly to an original cost rate base because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when prices and book values diverge significantly.

Q. What are the results of your Comparable Earnings analysis?

A. The process that I used to select the Comparable Earnings companies is described in Appendix J and shown on page 1 of Schedule 13. The historical rate of return on book common equity was 14.3% using the average measure of central tendency and 11.6% using the median value as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.1% average and 11.8% median values also provided on page 2 of Schedule 13.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is 11.70% (11.6% + 11.8% = 23.4% ÷ 2) and represents the Comparable Earnings result for this case.

CONCLUSION

Q. What is your conclusion concerning the Company's cost of equity?

6 For example, since 1854, there have been 30 business cycles having an average length of 51 months measured from trough to trough and 53 months measured from peak to peak. Hence, a 10-year measurement period in the Comparable Earnings approach is more than adequate to cover an average business cycle.

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable rate of return on common equity is 13.0% for the Florida Division. For reasons previously explained, the Company is only able to propose a 12.0% rate of return on common equity in this case. My studies indicate, however, that a higher 13.0% cost of equity can be justified given the Company's level of risk and management performance in successfully dealing with those risks.

Q. Does this conclude your prepared direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBITS

OF WILLIAM L. PENCE

ON BEHALF OF THE FLORIDA DIVISION OF

CHESAPEAKE UTILITIES CORPORATION

DOCKET NO. 000108GU

Q. Please state your name and present place of employment.

A. My name is William L. Pence. I am a member of the Florida Bar and a shareholder in the law firm of Akerman, Senterfitt & Eidson, P.A., 255 South Orange Avenue, Post Office Box 231, Orlando, Florida 32802-0231.

Q. What is your connection with the Florida Division of Chesapeake Utilities Corporation (the "Company") in this proceeding?

A. I serve as special environmental counsel for the Company. Specifically, I have been retained to provide counsel to the Company in connection with the investigation and remediation of environmental impacts at a certain former manufactured gas plant ("MGP") site located in Winter Haven, Florida.

Q. Can you please provide us with a brief description of your experience as an environmental attorney and your specific experience with environmental issues associated with former MGP sites?

A. I have been a practicing attorney for approximately twenty-one years, having received my law degree in 1979 from Syracuse University College of Law. A copy of my current resume is attached as Exhibit "A" to Composite Exhibit No. WLP-1. For the past thirteen to fourteen years, my practice has been exclusively in the environmental field. I represent private industry, utilities, municipal corporations and individuals in environmental regulatory matters related to assessment and remediation of contaminated sites; management of hazardous wastes; defense of state and federal environmental enforcement actions under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, the Resource Conservation Recovery Act, the Clean Water Act, the Emergency Planning and Community Right to Know Act, and similar state laws; and environmental risk management in connection with corporate and real estate acquisitions and divestitures. I currently represent four regulated utilities and three municipalities in connection with the management of environmental liabilities at 12 former MGP sites throughout Florida. My work at these sites includes interviewing and contracting with environmental consulting firms for assessment and remediation tasks, negotiation of consent orders and consent decrees with the Florida Department of Environmental Protection ("FDEP") and United States Environmental Protection Agency ("USEPA"), review of reports prepared by the consultants for transmittal to regulatory bodies, negotiation of cleanup orders with FDEP and USEPA, negotiation of insurance claims with insurance carriers and interviewing and contracting with remediation contracting firms. Approximately thirty-five (35%) of my practice today is devoted exclusively to former MGP sites.

Q. Have you ever provided written testimony before the Florida Public Service

Commission ("PSC") on behalf of a regulated utility in connection with a rate case and, if so, what was the general purpose of your testimony?

A. Yes. I provided written testimony on behalf of West Florida Natural Gas Company ("WFNG") in its rate case, Docket No. 871255-GU, and on behalf of Florida Public Utilities Company ("FPUC") in its rate case, Docket No. 940620-GU. The purpose of my testimony in each was to provide a brief history of the regulatory status of former MGPs in general, and to describe the nature and extent of work required to be performed by WFNG in connection with the former MGP located on property then owned by WFNG in Ocala, Florida, and by FPUC in connection with the former MGPs owned or operated by FPUC in Pensacola, Sanford, West Palm Beach and Key West, Florida.

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

A. I am here to provide the PSC with a brief history of the gas manufacturing operations conducted at the Winter Haven former MGP site, to review certain legal aspects of those operations insofar as they relate to environmental conditions at the site, to describe the Company's actions to date, to identify the Company's proposed future responses to the presence of environmental impacts resulting from the former MGP operations, and to provide a current estimate of remediation costs at the site.

Q. What is the connection of the Company with the former MGP site referenced above?

A. The Company is the current owner of a portion of the site and is the former owner/operator of the MGP. The site is located at 1705 Seventh Street, S.W., Winter Haven, Florida. An MGP was operated by the Company at the site from approximately 1928 to 1953, during which time the entire site was owned by the Company.

Q. Can you please provide us with a general description of the nature of MGP operations?

A. Prior to the availability of natural gas in Florida, gas used to light streets and houses was primarily made at MGPs. The manufacturing process for "carbureted water gas," the most common form of gas manufacturing in the 1900s and the method employed at the Winter Haven site, included passing steam over a bed of hot coals to produce "blue gas." The blue gas was then sprayed with hydrocarbons such as fuel oil and passed through a superheated chamber to thermally crack the hydrocarbons and produce energy-rich gases. The gas was then passed through wood shaving filled scrubbers and over iron oxide in purifier boxes prior to collection in a central holding tank for distribution. Common by-products of this process included tar, spent fuel oils and sludges, waste scrubber shavings and purifier box wastes. These by-products typically contain polycyclic aromatic hydrocarbons ("PAHs"), benzene, toluene, ethylbenzene, xylenes, phenols and cyanide.

Q. What environmental impacts are normally found in connection with former MGP operations?

A. Investigations at MGP sites have typically found coke, coal and clinkers in surface soils; tars and oily wastes in the bottom of gas holders, in tar tanks or in soils on site; wood shavings from the scrubbers; purifier box wastes; and fuel oil or light oils from tars in pits or in the soils on site. Soil and groundwater impacts detected at many

MGP sites in Florida include concentrations of PAHs, benzene, toluene, ethylbenzene, xylenes and cyanide in excess of current regulatory standards.

Q. What is the source of these environmental impacts?

A. Most are the result of routine operations at the MGPs. Inadvertent or accidental releases may have occurred at several of the process areas, including at the tar tanks, gas holders and associated piping, purifiers and petroleum storage areas.

Q. Were spills or releases of MGP waste materials in violation of any laws during the operation of the former MGPs?

A. Generally, no. Evidence of such releases have been detected at many of the former MGP sites located throughout the United States and the rest of the world, indicating a state of industrial practice at the time that the MGPs were in operation that was deemed normal and acceptable. It wasn't until the passage of the Clean Water Act ("CWA") in the early 1970s and the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") in 1980 that the Federal government began regulating such releases. Florida enacted legislation similar to the CWA and CERCLA in the early 1970s and 1983, respectively.

With the passage of CERCLA in 1980, the federal government imposed retroactive liability for remediating contaminated properties on certain classes of persons, including the owner or operator of the facility at the time of the release and the current owner or operator of the facility. Liability under CERCLA is strict, and, in most cases, joint and several. Thus, to succeed in a claim under CERCLA to compel remediation of a site, all the state or federal government need show is that the property is contaminated and that the defendant is within the class of persons deemed responsible under the Act, as described above. The state of Florida has a similar statutory liability scheme under Chapters 376 and 403, Florida Statutes.

Q. Please describe the history of state and federal regulatory interest in the environmental impacts associated specifically with former MGP sites.

A. MGP sites first became the subject of national attention in 1984. At that time, many former MGP sites, including the Winter Haven site, were identified in a study performed for the United States Environmental Protection Agency ("USEPA") entitled "Survey of Tar Waste Disposal and Locations of Town Gas Producers" ("EPA Survey"), first published in August 1984. Relevant excerpts of the EPA Survey are attached as Exhibit "B" to Composite Exhibit No. WLP-1. The EPA Survey constituted USEPA's "first step of a preliminary study to investigate the fate and potential environmental impact of by-products (such as tar) from the manufactured gas industry." The purpose of the EPA Survey was to identify the locations of former MGP facilities so that authorities might become aware of potential sites where environmental impacts may have resulted from prior gas manufacturing operations and practices.

In cooperation with state and federal environmental officials, the PSC notified gas utilities in June 1985 of concerns raised by regulatory bodies related to possible environmental impacts of the gas manufacturing operations of former MGPs. The PSC advised gas utilities in Florida that the Commission was interested in identifying former MGP sites in Florida and requested that the utilities provide certain information with respect to the known prior gas manufacturing operations conducted by the respective utilities.

Q. Did the Company respond to the PSC's June 1985 letter of inquiry?

A. Yes. In its response, the Company identified the location of the Winter Haven MGP site.

Q. Did other owners of former gas manufacturing facilities in Florida receive a similar letter from the PSC with respect to gas manufacturing operations?

A. Yes. The PSC's June 1985 letter of inquiry was sent to all natural gas distributors in the state of Florida with known or suspected prior gas manufacturing operations.

Q. Was the information received by the PSC in response to its inquiry ever provided to other regulatory bodies?

A. The responses to the letter of inquiry received by the PSC were later shared with the Florida Department of Environmental Regulation, now known as the Florida Department of Environmental Protection ("FDEP"), the administrative agency of the state charged with administering and enforcing the environmental laws and regulations of the state of Florida.

Q. What was FDEP's response to the discovery of former MGP sites in Florida?

A. In September 1985, FDEP notified each of its District Managers of the locations of former MGPs within their districts. Each FDEP District Manager was directed to conduct an investigation into the potential environmental impacts of such operations within their respective Districts. By letter dated March 25, 1986, a copy of which is attached as Exhibit "C" to Composite Exhibit No. WLP-1, FDEP advised the PSC that, due to experiences with a South Florida site, FDEP had discovered that a "walkover" inspection of former MGP sites in Florida was not useful in identifying potential environmental impacts arising from the former gas manufacturing operations. In the March 25, 1986, letter, FDEP stated that the assessment of subsurface conditions at the South Florida site disclosed the presence of organic compounds in soil, sediment, and groundwater, and concluded that:

> a preliminary contamination assessment will need to be completed for each site. We recommend that each property owner prepare a Preliminary Contamination Assessment Plan (PCAP) to sample site soil, groundwater, and surface water in accordance with the attached guidance. This should be coordinated with [FDEP] in Tallahassee.

Q. How has the Company responded to the discovery of the former MGP operations at the Winter Haven site?

A. I was retained as special environmental counsel in the mid 1980s to assist the Company in its investigation of potential environmental liabilities associated with the Winter Haven site. The Company's initial response was to dismantle and properly dispose of the former gas holder and its contents still present at the Winter Haven site in the mid 1980s. Following this effort, the Company executed a Consent Order with FDEP in February 1990. A copy of the Consent Order is attached as Exhibit "D" to

Composite Exhibit No. WLP-1. Pursuant to the terms and conditions of the Consent Order, the Company is obligated to investigate and remediate environmental impacts attributable to releases from the former MGP operations.

Q. At present, is the Company in compliance with its obligations under the Consent Order?

A. Yes.

Q. What activities has the Company undertaken since execution of the Consent Order?

A. Field work at the site has included extensive soil, sediment, groundwater and surface water sampling. In addition, shallow trenches were excavated throughout portions of the site to evaluate subsurface conditions and to delineate the more highly impacted areas. The results of these investigations are included in formal reports transmitted to FDEP for review and comment, including the Contamination Assessment Report dated July 1990; Contamination Assessment Report Addendum dated March 1993; June 21-22, 1995 Groundwater Sampling Results letter report dated August 15, 1995; Summary Assessment Report dated October 5, 1995; Sediment Sampling Results letter report dated October 15, 1997; and Additional Field Investigation Results Report dated May 27, 1999. The transmittal of the latter report marked the completion of the contamination assessment task at the site.

Q. Has the Company evaluated remediation options for the site?

A. Yes. As noted above, contamination assessment activities were materially completed with the submission of the supplemental soil and groundwater data to FDEP in May 1999. Following this submittal, the Company was directed to evaluate remediation options for the site. In June 1999, the Company implemented an Air Sparge/Soil Vapor Extraction ("AS/SVE") pilot study to evaluate the potential effectiveness of AS/SVE technology as a remedy for the majority of the site. Soil and groundwater impacts at the site consist primarily of benzene, toluene, ethylbenzene, xylenes, and polynuclear aromatic hydrocarbons. In general, the options for remediating these constituents at former MGP sites are limited to excavation and treatment of all impacted soils, implementation of some form of in situ remedy, or a combination of both. AS/SVE is a form of in situ remedy that provides for soil and groundwater remediation "in ground" by introduction of forced air into the groundwater and extraction of vapors from the overlying soils. AS/SVE does not create a material disruption to the ongoing use of a site during implementation, which makes it an attractive remedy at sites, such as Winter Haven, where the property is continuing to be used on a daily basis. By contrast, excavation and thermal treatment of impacted soils can interfere with site use over a period of several months during implementation of the remedy.

Q. Is AS/SVE an option for the Winter Haven site?

A. Yes. The Company delivered its AS/SVE Pilot Study Report to FDEP in January 2000. The AS/SVE Report concluded that AS/SVE is an appropriate remedy for the majority of impacts present at the site. The Company is currently awaiting FDEP's response to the AS/SVE Pilot Study Report. In addition to evaluation of the appropriate remedy for the site, FDEP has indicated that additional investigations are necessary for certain lake sediments located adjacent to the site. The Company is in negotiations with FDEP on the scope of such additional work. The Company does not believe at this time that the results of such an effort will evidence a need for remediation of the sediments.

Q. Has the Company undertaken a responsibility to keep the PSC advised of the Company's actions in responding to environmental impacts at the Winter Haven site?

A. Yes. Pursuant to the approved December 3, 1992 PSC Staff recommendation regarding the Company's depreciation study in Docket No. 920315-GU, the Company has provided periodic updates regarding the Company's investigations and other activities conducted at the Winter Haven MGP site.

Q. What additional work is left to be done at the Winter Haven site?

A. The Company believes that contamination assessment activities have been completed at the site, with the possible exception of further studies of adjacent sediments in Lake Shipp. The AS/SVE Report delivered to FDEP on behalf of the Company in January 2000 indicates that AS/SVE may be an appropriate remedy for most of the impacts present at the site. If FDEP agrees, the final remedy will be a combination of AS/SVE and excavation/thermal treatment of a limited volume of heavier impacted soils for which AS/SVE would not be effective as a remedy. If FDEP disagrees with AS/SVE as a remedy, excavation/thermal treatment of all impacted soils will most likely be the remedial action selected. In addition, further assessment of the adjacent sediments in Lake Shipp will be required. At this time, the Company does not anticipate that those sediments will require remediation.

Q. How long will it be before remediation activities are completed at the Site?

A. We currently expect to submit a final remedial design to FDEP in 2000. Assuming a reasonable time for FDEP's review and approval, it is most likely that the final remedy will be initiated in the year 2001. If AS/SVE is selected as the remedy, our experts advise us that the remedy will take approximately two (2) years to complete, with up to five (5) years of post-remediation monitoring to confirm cleanup. If excavation/thermal treatment of all impacted soils is selected as the remedy, our experts advise us that such activities can be completed within six (6) months after initiation, with up to five (5) years of post remediation monitoring to confirm cleanup.

Q. Has the Company made an effort to calculate estimated costs to complete remediation at the site, and, if so what are these costs?

A. Yes. Based upon currently known conditions at the site, the Company has calculated the cost to complete soil and groundwater remediation utilizing certain assumptions. The assumptions have been discussed with the environmental consultant performing work at the Winter Haven MGP site and are believed to be reasonable in light of work that is being conducted at similar sites throughout Florida and the rest of the country. These assumptions include identification of: (i) estimated volume of impacted soils to be remediated; (ii) most likely soil remediation alternatives; (iii) capital costs for construction of groundwater treatment systems; (iv) projected operation and maintenance costs of the groundwater treatment systems for the life of the remediation projects; and (v) performance monitoring costs. These costs have been calculated for each of the two remediation approaches described above, as well as for further assessment of sediments in Lake Shipp. Depending on the remedy ultimately accepted by FDEP, the estimated costs to complete assessment and remediation range from approximately $745,000 - $1.44 million. This range of costs reflects the costs of the two remedial alternatives: (i) AS/SVE with limited excavation/thermal treatment - $745,000; and (ii) excavation/thermal treatment of all impacted soils - $1.44 million. Both estimates include the projected costs for post remediation monitoring and the continuing investigation of the sediments in Lake Shipp.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MR. ELIAS: Staff would move the prefiled direct testimony of witnesses Sweeney and Draper.

CHAIRMAN DEASON: Okay. Without objection, show then, that that testimony shall be inserted into the record. I show that witness Sweeney has no exhibits?

MR. ELIAS: There's one exhibit.

CHAIRMAN DEASON: There is one exhibit? Okay.

MR. ELIAS: Each one has one.

CHAIRMAN DEASON: Okay. That will be composite Exhibit 7. And for witness Draper that will be Exhibit 8.

(Exhibits 7 and 8 marked for identification.)

MR. ELIAS: And then, we have one composite exhibit, which I'd ask be identified as composite Exhibit 9.

CHAIRMAN DEASON: Yes, this is the large volume --

MR. ELIAS: Yes.

CHAIRMAN DEASON: -- you have indicated as Staff's Exhibit Number 1. For purposes of the record, it will be identified as Exhibit 9.

(Exhibit 9 marked for identification.)

CHAIRMAN DEASON: And the company has no objection to this exhibit?

MR. SCHIEFELBEIN: No objection, sir.

CHAIRMAN DEASON: Okay. Exhibits 7, 8, and 9 are admitted.

(Exhibits 7, 8 and 9 admitted into the record.).

DIRECT TESTIMONY OF HILLARY Y. SWEENEY

Q. Please state your name and business address.

A. My name is Hillary Y. Sweeney and my business address is Hurston North Tower, Suite N512, 400 W. Robinson Street, Orlando, Florida, 32801.

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

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst III in the Division of Regulatory Oversight.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since November, 1993.

Q. Briefly review your educational and professional background.

A. In 1993 I received a Bachelor of Science degree in Accounting from Florida A & M University. In November, 1993, I was hired in the Division of Water and Wastewater at the Florida Public Service Commission as a Regulatory Analyst I. I was assigned primarily to review staff-assisted rate cases. In August 1997, I transferred to the Division of Auditing and Financial Analysis to work in the Orlando District office as an auditor at the Regulatory Analyst III level.

Q. Please describe your current responsibilities.

A. Currently, I am a Regulatory Analyst III with the responsibilities of planning and directing audits of regulated companies, and assisting in audits of affiliated transactions. I also am responsible for creating audit work programs to meet a specific audit purpose.

Q. Have you previously presented expert testimony before this Commission or any other regulatory agency?

A. Yes, I testified in the Mid-County Services, Inc. rate case, Docket No.

971065-SU and sponsored specific audit findings in that docket.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of the Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU. The audit report is filed with my testimony and is identified as HYS-1.

Q. Was this audit report prepared by you?

A. Yes, I was the audit manager in charge of this audit.

Q. Please review the work you performed in this audit.

A. For the rate base, I examined account balances for utility-plant-in-service (UPIS), contributions-in-aid-of-construction (CIAC), accumulated depreciation, and accumulated amortization of CIAC and brought the balances forward from June 30, 1989. I also reconciled rate base balances authorized in Commission Order No. 23166, issued July 10, 1990, to the June 30, 1989 general ledger balance, tested plant account balances using stratified sample methods, examined supporting documentation for sample CIAC additions and matched to the Commission-approved tariff amounts, and compiled working capital accounts. I also tested additions to accumulated depreciation and accumulated amortization for proper rates and calculations, tested working capital for interest-bearing amounts, tested unfunded reserves, and tested non-utility transactions.

For the net operating income, I compiled and reviewed utility revenue and operating and maintenance accounts for the year ended December 31, 1999. I chose a judgmental sample of customer bills and recalculated them using Commission-approved rates. I verified a judgmental sample of operation and maintenance expenses and examined the invoices and other supporting documentation. I tested the calculation of depreciation expense and examined support for taxes other than income and income taxes.

For the capital structure, I compiled components of the capital structure for the year ended December 31, 1999, reconciled interest expense to the terms of the notes and bonds, and confirmed note balances at December 31, 1999.

Q. Please review the audit exceptions in the audit report.

A. Audit Exceptions disclose substantial non-compliance with the Code of Federal Regulations Title 18, Part 201, Uniform System of Accounts (USOA), Commission rules, Commission orders, and formal company policy. Audit Exceptions also disclose company exhibits that do not represent company books and records and company failure to provide underlying records or documentation to support the general ledger or exhibits.

Audit Exception No. 1 discusses the capitalized sales tax on plant additions. The utility reported 1999 year-end balances of $4,000,202 and $1,053,519 for Accounts 376, Mains (Plastic), and 381, Meters, respectively. The 1999 ending balance in Account 376 (Mains-Plastic) is overstated by $2,324. The utility charged additional sales tax of $1,114 ($18,571 x .06) and $1,210 ($20,161 x .06) on the total amount of two invoices. I recommend that the utility should reduce Account 376 by $2,324 ($1,114 + $1,210).

The utility also charged Account 381 (Meters) with an additional sales tax of $575 ($9,582.07 x .06) on the total amount of an invoice. The utility should reduce Account 381 by $575.

Audit Exception No. 2 discusses the acquisition adjustment. In the utility's last rate case, Docket No. 891179-GU, the Commission issued Order No. 23166, on July 10, 1990. In this order, the Commission disallowed $509,422 in acquisition adjustment. The utility reported a 1999 year-end acquisition adjustment balance of $509,422 in its general ledger. The utility did not make the Commission-ordered adjustment to its books. However, it did remove this amount in its Minimum Filing Requirements (MFRs). Per Commission Order No. 23166, the utility should remove $509,422 from Account 114.1, Excess Cost of Acquisition-New-CFG Adjustments.

Audit Exception No. 3 discusses PGA revenues, PGA expenses, and PGA taxes. The utility included its PGA revenues, PGA expenses, and PGA taxes in the NOI schedules in the MFRs. In accordance with Commission Order No. PSC-92-0924-FOF-GU, issued September 3, 1992, in Docket No. 911150-GU, it is appropriate to remove PGA-related items that are recoverable through the PGA Cost Recovery Clause from the NOI schedules. While the projected amounts for the years 2000 and 2001 assume no over/under recovery, I recommend that these amounts should be removed from the NOI schedules in the MFRs.

Audit Exception No. 4 discusses common equity. The utility's general ledger reports a December 31, 1999 balance of $11,216,456 and a 2000 beginning balance of $11,809,982. The MFRs show a 1999 year-end common equity balance of $11,809,982. The utility does not record closing journal entries for the expense and revenue summary accounts. However, it does reflect the net effect in the beginning balance of the next year. The difference, $593,526 ($11,809,982-$11,216,456), is net income. The opening balance for the year 2000 for common equity reflects an adjustment to include net income. The utility should be required to make these journal entries to the general ledger accounts as part of its end of year closing entries. Closing and adjusting entries posted for the purpose of recording net operating income should be visible in the utility's general ledger accounts.

Audit Exception No. 5 discusses the flex-rate liability. In the cost of capital schedules, the utility reported a 13-month average balance for flex-rate liability of ($46,880). This represents a liability of $23,490 for the period October, 1994 through September, 1995, plus a liability of $23,390 for the period October, 1995 through September, 1996. MFR Schedule B-13 reflects an adjustment of ($46,880) to miscellaneous current liabilities to reflect the flex-rate liability 13-month average balance. MFR Schedule D-1 also reflects an adjustment of $46,880 to flex-rate liability the 13-month average balance. The utility made an arithmetic error when calculating the 13-month average. An additional $10,305 should be removed from the current liabilities section of working capital. This change will have the effect of increasing the 13-month average balance of working capital from $498,227 to $508,532. The flex-rate liability, a zero-cost component of the capital structure, should also be increased by $10,305. This increase will not change the weighted average cost of capital, 8.26 percent, because of its small size.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF DAVID J. DRAPER

Q. Please state your name and business address.

A. My name is David J. Draper. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0865.

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

A. I am employed by the Florida Public Service Commission, in the Finance and Tax Section of the Division of Economic Regulation, as a Regulatory Analyst III.

Q. Please outline your education qualifications and work experience.

A. I graduated from Florida State University in 1994 with Bachelor of Science degrees in Accounting and Finance. After graduation, I was employed full-time at the Florida Department of Revenue where I reviewed and examined various tax forms for accuracy and completeness. In addition, I corresponded with taxpayers and researched account information to ensure proper compliance with Florida Statutes. In 1995, I accepted an auditing position with the Florida Public Service Commission in which I audited various regulated Florida utilities. In 1997, I took my present position with the Commission working in the Finance Section analyzing return on equity, cost of capital and capital structures of public utilities regulated by the Commission. I am currently pursuing a Master of Business Administration degree at Florida State University.

Q. Have you previously testified on cost of capital?

A. No. I have, however, prepared and offered recommendations on cost of capital issues before this Commission.

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

A. The purpose of my testimony is to establish the appropriate cost of common equity for the Florida Division of the Chesapeake Utilities Corporation

(Chesapeake or Company) for use in determining an appropriate allowed rate of return on equity.

Q. What principles provided the framework for your determination of a fair rate of return?

A. The principles established by the Supreme Court of the United States in Bluefield Water and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Company 320 U.S. 591 (1944), provided the primary legal basis for my analysis. The Supreme Court held in both the Hope and Bluefield decisions that the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital.

Q. In addition to the principles established by the Hope and Bluefield decisions, what other conditions did you consider?

A. Based on my understanding of the Hope and Bluefield decisions, a regulated utility should be allowed to recover all costs prudently incurred in the provision of utility service, including an appropriate return on common equity capital. Recovery of all prudently incurred costs, including capital costs, effectively balances the interests of investors and ratepayers. Investors are provided with a return commensurate with returns on investments of comparable risk, while ratepayers pay the true cost for the service provided.

Q. How does your analysis of a fair rate of return on Chesapeake's common equity meet these basic legal criteria?

A. My analysis of an appropriate rate of return on Chesapeake's common equity capital is based upon an evaluation requirement for comparable risk common equity investments as determined through the direct application of capital market valuation models to current financial and economic data. In my opinion, a market-based equity pricing analysis satisfies the comparable returns, capital attraction, and financial integrity guidelines established by the Hope and Bluefield decisions for determining a fair and reasonable rate of return on common equity capital.

Q. What have you concluded is the cost of common equity capital for Chesapeake?

A. Based upon the results of my analysis, I conclude the current cost of common equity capital for Chesapeake is 11.3%.

Q. Please describe your general approach to determine the cost of common equity capital.

A. In order to properly evaluate the returns obtained through use of a market-based equity pricing analysis, I first examined general economic conditions, as well as industry and company factors, which drive capital market return requirements. I then applied two generally accepted market rate of return models to an index of comparable companies as a means to estimate the cost of common equity capital for Chesapeake.

Q. How do general economic conditions impact capital market return requirements?

A. The interrelated factors of inflation and interest rates have a significant impact on investor return requirements. Increases in the general level of prices impact interest rates because investors are unwilling to commit their funds unless they are adequately protected against future losses in purchasing power. If investors anticipate a higher rate of inflation, they will adjust their return requirements upward to guard against the erosion of purchasing power.

Q. Please discuss the current economic environment and current expectations regarding inflation and interest rates.

A. The annual inflation rate, as measured by the change in the Consumer Price Index (CPI), was 4.1% for the first quarter of 2000 and decreased to 3.6% by the second quarter. The August 1, 2000, issue of the Blue Chip Financial Forecasts projects the annual inflation rate will decrease to 2.8% by the third quarter of 2000. The drop in CPI is widely attributed to the Federal Reserve Board's action to control inflation. The Federal Reserve has taken actions that have increased the Federal Funds rate six times in the last 13 months in an effort to slow the economy and ward off inflation. The Federal Funds rate, currently at 6.27% for the second quarter, represents the rate banks charge on overnight loans to each other and depends on the amount of reserves in the banking system. Typically, the Federal Reserve targets the Federal Funds rate by increasing or decreasing reserves in the banking system, which, in turn, controls the supply of money. This is the most common way the Federal Reserve carries out monetary policy and is one tool used to control inflation. Although the national economy is still growing there are signs of a slowdown and economists generally believe that inflation is under control.

Q. What is your analysis of conditions in the natural gas local distribution company (LDC) industry?

A. The LDC industry faces risks and opportunities. Bypass of the LDC by large industrial customers and competition from alternative fuels continue to be significant risks. Flexible rate design mitigates these risks by allowing the LDC to retain industrial customers and compete with other fuels available to industrial customers. An additional concern is the effect of the industry restructuring spurred by Order 636 of the Federal Energy Regulatory Commission (FERC). Convergence of electric and gas companies within the industry is happening quickly. According to Standard & Poor's Industry Surveys for Natural Gas Distribution, it is expected that in the next several years we will see a single industry that comprises fewer, larger, and more diversified companies competing to sell gas, electric, and other energy products and services to wholesale and retail customers alike. As competition within the energy market intensifies, the success of the new energy companies will be determined not only by the size of their customer base, but by the diversity of the products and services offered to their customers.

Q. Please discuss the effect FERC Order 636 has had on natural gas local distribution companies.

A. For interstate pipeline companies, Order 636 removed the obligation to provide a supply of gas to end of use customers and it required unbundling of pipeline rates for sales, transportation, and storage of gas. The supply obligation, and the risks inherent in it, now resides with the LDCs, which must purchase supplies of gas from producers and reserve pipeline capacity to transport the gas. However, this risk carries less weight reduced because Order 636 does not represent a sudden change, but is instead the culmination of gradual changes by FERC. Pipelines have been unbundling rates and LDCs have been purchasing gas since FERC Order 436, which began open access, was issued in 1985. Also, the proceedings that resulted in Order 636 began in 1991. Order 636 became effective on November 1, 1993. LDCs adequately managed gas supplies during the record-setting cold winter that followed, which was a good test of how LDC's can manage in the post-Order 636 environment. Still, one extreme winter does not constitute a complete test. I believe there remains some uncertainty regarding the effects of Order 636 on LDCs.

Q. What opportunities exist for LDCs?

A. Natural gas has a very high and growing market share in the U.S. energy market. It is a clean, efficient, competitively-priced fuel in ample supply. In addition, both the Clean Air Act Amendments passed in 1990 and the National Energy Policy Act of 1992 encouraged the use of natural gas. Many LDCs face attractive prospects for expanding their share in residential, commercial, and industrial markets as well as developing markets for fleet vehicles, residential and commercial gas cooling, and cogeneration.

Q. What potential risks does Chesapeake face?

A. In his testimony, Jeff Householder lists six primary business risk factors facing Chesapeake today. The first risk factor concerns the Company's ability to respond to the needs of its customers by providing the product and services they demand. Second, economic downturns in the primary industries served by the Company can have a significant impact on earnings. Third, if the Company is unable to grow its earning base by feasibly expanding into new service areas, rates will ultimately become non-competitive. The fourth risk is becoming too dependent on non-captive, cyclical, and in some cases, declining industrial accounts. The fifth risk is competition from alternate fuel providers, which pose an increasing risk to the Company's market share. Lastly, over the past two years, three gas pipeline companies have proposed major gas pipeline expansions targeted to large customers and electric power plants. Two of these planned projects extend across the Gulf of Mexico and come ashore around South Florida.

More than 90% of Chesapeake's thorough-put comes from large customers. Many of these customers are located near the proposed pipeline projects. The greatest risk faced by Chesapeake is that these customers may bypass the Company and connect directly to the pipeline. In addition, the Commission's recent decision to allow all non-residential customers to choose their natural gas supplier should raise competition between marketers and LDC's, in turn exerting a downward pressure on natural gas prices (Docket No. 960725-GU, Order No. PSC-00-0630-FOF-GU).

Q. What opportunities exist for Chesapeake?

A. Access to a new pipeline may promote economic development and allow Chesapeake to increase its customer base. Chesapeake's customer base is expected to show reasonable growth in the coming years and the Company is expanding its pipeline into new areas to capture a growing market of industrial and residential customers.

Q. What financial models did you use to determine the required return on common equity for Chesapeake?

A. To determine the required return on common equity for Chesapeake, I used a two-stage annually compounded discounted cash flow (DCF) model and a Capital Asset Pricing Model (CAPM). I applied these models to the common stocks of the companies in the <u>Value Line</u> LDC index. This procedure allowed me to determine the general cost of equity for natural gas LDCs. Relying on an index of comparable companies, instead of a single company, helps reduce forecasting errors and should provide more reliable information for use in measuring the cost of equity. Use of an index of companies mitigates the impact of abnormal conditions that might be associated with one company. In addition, I applied the two-stage annually compounded DCF model to the common stocks of an index of electric companies.

Q. Please describe the companies included in the Value Line LDC and electric indices.

A. The companies in the Value Line LDC Index are representative of the LDC industry. Companies whose gas operating revenues represented less than 80% of revenues in 1998 (according to C.A. Turner Utility Reports of Public Utilities), were removed from the index. Gas operating revenues as a percentage of the total revenues averaged 94% for group. Since Chesapeake had 100% of its revenues from gas sales in 1998, using an index with an average of 94% ensures the index is representative of Chesapeake's business risks. Being in the same industry, these companies face similar risks and are subject to similar economic and regulatory influences. I have listed the companies and their investment characteristics in Exhibit DJD-1. The investment risk characteristics for the index have an average Value Line safety ranking of 2, an average Value Line beta of 0.60, a range of bond ratings from "AA-" to "BBB-", and an average equity ratio of 53.3%.

The companies used in the comparable electric index, all had a Value Line beta of .60, paid dividends and each had projected dividends and earnings per share growth rates above zero. In addition, the index had an average S&P bond rating of "A." As with the natural gas index, I believe that this index of electric companies faces the same risks and opportunities, and are subjected to comparable economic and regulatory influences similar to Chesapeake. I have listed the index of electric companies and their investment characteristics in Exhibit DJD-1A.

Q. What is the theory behind a DCF model?

A. The DCF model is based on two principles. First, investors value an asset based on the future cash flows they expect to receive. Second, investors value a dollar today more than a dollar received in the future, meaning that they assume the time value of money. Therefore, in a DCF analysis, the cost of equity is the discount rate that equates the present value of expected cash flows associated with a share of stock to the present market price of the stock. In Exhibit DJD-2, I have provided the basic DCF equation and defined the terms. The basic model has three simplifying assumptions: 1) dividends are paid annually and grow at a constant rate; 2) the price of the stock is determined on the dividend payment date; and 3) dividends increase once a year starting one year from the dividend payment date.

Q. What DCF model have you used in your analysis?

A. I have used a two-stage annually compounded DCF model. An assumption behind the basic DCF model is that dividends grow at a constant rate. However, growth in dividends can vary from period to period. A two-stage DCF model, also known as a non-constant growth model, allows for two periods of dividend growth: a near term period during which dividends are specifically forecasted and a subsequent period of sustainable growth. In Exhibit DJD-3, I have presented the equation for my two-stage annually compounded DCF model and defined the terms. This model is consistent with the valuation practices of institutional investors and financial analysts. An additional advantage of the two-stage model is that it can use the specific dividend forecast from Value Line, and then use a sustainable growth rate. The two-stage model allows for more precision than the basic model.

Q. What are the inputs for your DCF model?

A. I used current stock prices for the companies in the Value Line index, specific dividend forecasts for the initial growth period, and a sustainable or long-term growth rate. For current stock prices, I first calculated the average of each company's high and low stock prices for July 2000. From these computations, I then calculated an average stock price for the index, which is the input to my model. I used Value Line's forecasted dividends for the years 2001 and 2004. I assumed a constant growth rate between these years to estimate dividends for the initial growth period. I then calculated the long-term growth rate using the earnings retention method, also known as the b x r approach. The inputs for my earnings retention method are Value Line's expected earned return on equity (r) and the expected retention rate (b) for 2004.

Q. Have you included an allowance for issuance costs in your DCF model?

A. Yes. My DCF model includes an allowance for issuance cost, calculated as 3% of the stock price. An allowance for issuance cost enables the utility to recover the costs incurred when issuing common stock. Issuance costs include registration fees, legal fees, underwriter fees, and printing and mailing expenses. Investors could not earn the required return on their investment without an issuance cost adjustment. The sales price of the stock will exceed the net proceeds to the company because it will incur issuance costs. A company can incur these costs whether the stock is publicly traded or privately held. Conceptually, this situation with common stock is similar to that of bonds and preferred stock. With bonds, for example, the cost charged to ratepayers reflects issuance costs and is recovered over the life of the bond. The cost to the company for a specific bond issue is the interest expense plus the amortization of issuance costs divided by the principal value less the unamortized issuance costs. The result is that the cost to the utility is greater than the return to the creditor. Unlike bonds, common stock does not have a finite life. Therefore, issuance costs cannot be amortized and must be recovered by an upward adjustment to the allowed return on equity. This adjustment reflects the fact that, due to the issuance costs, the utility earns a return on an equity balance that is less than the actual amount paid by investors. Historically, utility underwriting expenses associated with issuing common stock have averaged 3 percent of gross proceeds.

Q. What are the results of your DCF analysis?

A. The results of my DCF analysis show that the cost of equity for the comparable natural gas index is 10.3% and 10.9% for the comparable electric index. Exhibits DJD-4 and DJD-4A show the inputs and results of my analysis.

Q. What is the theory behind the CAPM?

A. The CAPM was first introduced by William Sharpe in 1964. It extended modern portfolio theory to introduce the notions of systematic and specific risk. CAPM divides the risk of holding risky assets into systematic and specific risk. Systematic risk is the risk of holding the market portfolio. As the market moves, each individual asset is more or less affected. To the extent that any asset is affected by such general market moves, that asset entails systematic risk. Systematic risk can be measured using beta, which is defined below.

Specific risk is the risk which is unique to an individual asset. It represents the component of an asset's volatility which is uncorrelated with general market moves. The expected excess return of an investment above the risk-free rate is just the investment's beta multiplied by the expected excess return on the broad market index. According to CAPM, the marketplace compensates investors for taking systematic risk, but not for taking specific risk. This is because specific risk can be diversified away. When an investor holds the market portfolio, each individual asset in that portfolio entails specific risk, but through diversification, the investor's net exposure is just the systematic risk of the market portfolio. The theory underlying the CAPM is quite simple. The expected return on common equity depends on the beta of that company's equity. The beta is a measurement of stock price volatility relative to a broad market index. If a stock moves up or down twice as much as the market, it has a beta of 2. If it moves one half as much as the market, its beta is 0.5. The CAPM models the systemic risk in a particular asset. Systemic risk is associated with the movement of a market or market segment as opposed to distinct elements of risk associated with a specific security.

Q. Please describe your Capital Asset Pricing Model.

A. In Exhibit DJD-5, I have listed the equation and the components of the CAPM. There are three basis components to the CAPM: 1) the expected risk-free rate of return; 2) the stock's expected relevant market risk called "beta;" and 3) the expected return on the stock market taken as a whole. The risk-free rate (R_F) is derived from the average projected yield of the 30-year Treasury bond. Treasury bonds are a recognized bench mark for risk-free rates, since there is little risk of the U.S. Government defaulting on its bonds. The required market return (R_m) was determined by using Value Line's database of listed companies and then screening those companies to remove anomalies. In my opinion, removing anomalies such as companies that don't pay dividends, having negative dividend growth, negative projected earnings growth or either growth greater than twenty-percent, is an accurate representation of the market return. The characteristics of companies used in the index required that dividends be paid to shareholders and have both projected dividend growth and projected earnings per share of less than twenty-percent, but greater than zero. For each of the screened companies, a basic DCF analysis was performed, then an average of all the DCF results were used as the required market return. In my opinion, the average beta for the Value Line LDC index is a reasonable proxy for the assumed beta for Chesapeake's Florida Division.

Q. What is the cost of equity for the LDC index based on your CAPM analysis?

A. Based on my CAPM analysis, the cost of equity for the LDC index is 9.5%. Exhibit DJD-5 presents the results of my CAPM analysis and definitions.

Q. Given the results of your DCF and CAPM analyses, what range did you determine as the cost of equity?

A. Based on the results of my CAPM and DCF analyses, I have determined that the range for the cost of equity should be from 9.5% to 10.3%.

Q. Is this range of return appropriate for Chesapeake?

A. No. While the range I calculated is an appropriate starting point, Chesapeake faces greater risks than the companies in the index and should be allowed a higher cost of equity.

Q. Why is Chesapeake's risks higher than the companies in the index?

A. To determine Chesapeake's specific risk, I compared the average Net Plant and Net Income of the companies in the gas index to that of Chesapeake. Exhibit DJD-1 shows that Chesapeake has significantly less net plant and net income than the companies in the index. As such, Chesapeake is less diverse with respect to its markets and may be more severely affected by economic changes. Studies suggest that smaller firms are generally riskier than larger firms and have higher costs of equity. Small firms experience more business failures and have a less liquid market for their shares. In addition, Chesapeake is a regulated company in a very competitive and diverse energy service market. Chesapeake must compete with alternate fuel service providers, such as propane and fuel oil, in order to maintain and expand its customer base. Chesapeake must also compete with the electric companies in providing energy and services to new and existing customers.

Q. How did you adjust the cost of equity that you calculated to estimate the cost of equity for Chesapeake?

A. As I noted earlier, the bond ratings for the companies in the Value Line comparable index of natural gas LDCs range from "AA" to "BBB" (See Exhibit DJD-1). Using Standards & Poor's (S&P) system as an example, bonds in the top four categories of bond ratings, "AAA", "AA", "A", and "BBB", are considered investment grade and are eligible for bank investment under the regulations of the Controller of the Currency. In addition, laws of various states restrict investments by banks, insurance companies, pension funds and fiduciaries generally to investment grade bonds. Bonds rated "BB" or lower are considered speculative and may not have the ability to make timely interest and principal payments. As a public utility providing an essential service, and given efficient management and a sound regulatory environment (S&P considers Florida a supportive regulatory environment), Chesapeake's credit should be considered investment grade. I used the historic spread between the yields on "A" and "BBB" public utility bonds as a proxy for the higher return required for Chesapeake. The median and average of the companies in the Value Line index have a bond rating of single A ("A"). Therefore, I have used a "A" rating as a representative bond rating for the index. The "BBB" rating is the lowest level of investment grade. By using the spread between "A" rating and a "BBB" rating, a proper adjustment for Chesapeake's smaller size should be ensured.

Q. How did you calculate the historic spread between "A" rated and "BBB" rated public utility bonds?

A. I subtracted the yield on "A" rated public utility bonds from the yield on "BBB" rated public utility bonds as reported in Moody's Bond Survey for the last 120 months and averaged the results. Exhibit DJD-6 presents the data and results. For June 2000, the spread between "A" and "BBB" public utility bonds over the past 120 months is 37 basis points.

Q. What was the resulting cost of equity range for Chesapeake when adjusting for the bond yield differential?

A. Adding the 37 basis points to my indicated range for the cost of equity resulted in a range from 9.9% to 10.7%.

Q. Does this range appropriately take into account the risk faced by Chesapeake?

A. No. As I discussed earlier, the natural gas industry is under increasing competitive pressures from electric utilities. According to the S&P's Industry Survey, it is expected that within the next several years, we will see a single energy industry that comprises fewer, larger, and more diversified companies competing to sell gas, electric and other energy products and services to wholesale and retail customers alike. Since the start of the new year, six major mergers have occurred between electric and gas companies and eleven major mergers occurred in 1999. It will become increasingly difficult for a small LDC, like the Chesapeake Division, to compete with these larger energy providers in the coming years.

Q. How would you compensate for this risk?

A. In order to compensate for the risk of increased competition, I would add a premium for risk to the range of indicated model results.

Q. How would you calculate this premium for competitive risk?

A. I would add the point difference between the DCF results of the electric index and DCF results of the LDC index to the range of the model results indicated. The difference between the two DCF models is 65 basis points.

Q. What is the appropriate cost of equity for Chesapeake?

A. After adding the premium for competitive risk, I have determined that the appropriate range for the cost of equity for the Florida Division of Chesapeake Utilities Corporation, is from 10.6% to 11.3%. In my opinion, the top of the range should be used for the cost of equity for Chesapeake. Exhibit DJD-7 presents the range for Chesapeake. Determining the appropriate point estimate is a difficult but necessary decision in estimating the cost of equity and ultimately, it rests on judgment. Chesapeake has exposure to the remaining uncertainty surrounding FERC Order 636 similar to the companies in the index, but unlike those companies only one pipeline currently serves Chesapeake. As discussed earlier, three large gas pipeline companies are proposing a second pipeline to serve South Florida. There are potential benefits to Chesapeake when the pipeline is built, but I believe there are greater risks in that existing customers may bypass and connect directly to the second pipeline. With the increased consolidation of electric and gas companies, competitive pressures will increase, causing financial margins to decrease for LDCs. In addition, the Commission's recent decision to allow small businesses to choose their natural gas supplier should raise competition between marketers and LDC's, in turn exerting a downward pressure on natural gas prices. In my opinion, the top of the range for the cost of equity is reasonable and will compensate Chesapeake appropriately for the remaining uncertainty and risks that I have just discussed. Historically, the Florida Public Service Commission has allowed a range around the authorized cost of equity. Therefore, I recommend a return on common equity for Chesapeake of 11.3% for all regulatory purposes, with a range of plus or minus 100 basis points.

CHAIRMAN DEASON: Then, we have a rebuttal witness, Mr. Schiefelbein?

MR. SCHIEFELBEIN: Yes, sir. That would be Mr. Moul.

CHAIRMAN DEASON: Show, then, that that testimony is inserted into the record.

CHAIRMAN DEASON: Are there exhibits accompanying the rebuttal?

MR. SCHIEFELBEIN: Yes, there are.

CHAIRMAN DEASON: Okay. Those accompanying exhibits will be identified as Exhibit 10. And without objection, Exhibit 10 shall be admitted into the record.

(Exhibit 10 marked for identification and admitted into the record.).

PREPARED REBUTTAL TESTIMONY OF PAUL R. MOUL

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

A. My name is Paul R. Moul and I am Managing Consultant at P. Moul & Associates, Inc. My business address is Cherry Tree Corporate Center, 535 Route 38 East, Suite 200, Cherry Hill, New Jersey 08002-2953.

Q. Mr. Moul, have you previously submitted Direct Testimony in this proceeding?

A. Yes. My direct testimony and associated financial data was submitted with the Company's case-in-chief on May 15, 2000.

Q. What is the purpose of your Rebuttal Testimony?

A. The Florida Division of Chesapeake Utilities Corporation ("Florida Division" or the "Company") has requested that I comment on and rebut the testimony presented by Mr. David J. Draper, a witness appearing on behalf of the Staff of the Florida Public Service Commission.

Q. Do you have exhibits to accompany your rebuttal testimony?

A. Yes. I have prepared Composite Exhibit No. PRM-3 consisting of 9 schedules to accompany my rebuttal testimony.

Q. Before proceeding with your rebuttal, please describe some of the market events that have transpired since the time your direct testimony was prepared.

A. During the past fifteen months, the Federal Reserve Board's Open Market Committee has significantly tightened monetary conditions by increasing the Fed Funds rate on six occasions (i.e., June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000). In taking its action on February 2, the Open Market Committee stated:

> "The Committee remains concerned that over time increases in demand will continue to exceed the growth in potential supply, even after taking account of the pronounced rise in productivity growth. Such trends could foster

inflationary imbalances that would undermine the economy's record economic expansion."

On May 16, the Open Market Committee reiterated its position by stating:

"Increases in demand have remained in excess of even the rapid pace of productivity-driven gains in potential supply, exerting continued pressure on resources. The Committee is concerned that this disparity in the growth of demand and potential supply will continue, which could foster inflationary imbalances that would undermine the economy's outstanding performance."

"Against the background of its long-term goals of price stability and sustainable economic growth and of the information already available, the Committee believes the risks are weighted mainly toward conditions that may generate heightened inflation pressures in the foreseeable future."

The Fed Funds rate has increased by one and three quarters percentage points (i.e., 1.75%) rising to 6.50%, its highest level since the first quarter of 1991. The discount rate is now up by one and one-half percentage points from its low in the fourth quarter of 1998, which coincided with the height of the Asian currency and stock market crisis. Against this backdrop, additional rate increases cannot be ruled out, especially after the presidential election, if inflationary pressures persist.

Q. How has the Fed's policy impacted the yields on corporate bonds?

A. Since February 2000 (the latest bond yields contained in my original financial data), the yield on A rated public utility bonds has remained essentially unchanged, albeit it increased through May and declined thereafter (see Composite Exhibit No. PRM-3, Schedule 1). While the cost of corporate capital has remained at about the same levels in July that it was in February 2000, the yield on 30-year Treasury bonds has fallen. As shown by the data presented graphically on Composite Exhibit No. PRM-3, Schedule 2, the interest rate spread between the yields on 30-year Treasury bonds and A rated public utility bonds has expanded from the unusually high levels that I described in my direct testimony. As I described therein, the spread between the yield on A rated public utility bonds and Treasury bonds was about 1.75 percentage points in 1999 (see page 4 of Schedule 10 of Composite Exhibit No. PRM-1). As shown on Composite Exhibit No. PRM-3, Schedule 2, the yield spread between corporate and Treasury bonds has expanded to 2.48 percentage points in the second quarter of 2000. This situation continues to point to the high cost of corporate capital vis-a-vis the yield on Treasury obligations.

Q. Will you identify the areas of controversy concerning the Company's rate of return in this proceeding?

A. The central areas of dispute between Mr. Draper and the me in this case involve: (i) the selection of proxy companies to measure the cost of equity, (ii) the determination of a reasonable DCF cost rate, and (iii) the proper inputs to be used in the CAPM measure of the cost of equity.

Q. Do you agree with the selection of proxy companies used by Mr. Draper?

A. Not specifically. I have concerns with the companies that Mr. Draper has used to measure the cost of equity. First, he has employed many of the companies from the Value Line source without narrowing his group further for the risks associated with the Company. Second, he has not eliminated companies that are targets of mergers and acquisitions (M&A).

Three companies within the Value Line Group should be eliminated from the proxy group because they are now or recently have been the targets of acquisition. Those companies are CTG Resources, Providence Energy, and Southwest Gas. In an industry significantly influenced by consolidation, the stock prices of the target companies become substantially influenced by acquisition premiums that make a cost of equity determination for those companies problematic. M&A activity has implications for the dividend yield component of the DCF and the growth component of the DCF.

Q. What specific problems arise when using companies that are targets in M&As?

A. The M&A activity has a significant impact on investor expected growth. Due to the proposed acquisitions, there has been the run-up in stock prices of the gas utilities related to M&A expectations, either announced or anticipated. This price action has fundamentally changed the investment horizon associated with investors' growth expectations for the gas utilities. Investment horizons have shortened considerably in the context of prices offered in proposed M&A transactions. In the application of the DCF model, future returns are sometimes considered as an infinite number of growing dividends. However, when a company is the target of an acquisition, such as the three companies identified previously, a more defined number of cash flows is reflected in the stock price with particular emphasis being placed on the acquisition price (i.e., the liquidating dividend) of the stock. That is to say, today's stock price is the product primarily of the buy-out price of the stock and <u>not</u> an infinite dividend stream. As such, the long-term horizon of future dividend payments ceases to be the focus of investors. Rather, the acquisition price becomes the paramount consideration because the future value of the stock is established by reference to the acquisition price along with dividend payments that occur up to the time the company is acquired and its stock no longer trades.

Further, when a premium is offered to obtain control of a target company and to induce existing stockholders to sell their shares, the stock price disconnects from the earnings forecasts made by securities' analysts when the target company operated independently. After the combination occurs in the merger/acquisition, the surviving company will be able to attain increased shareholder value through economics of scope and scale that increase productivity and profitability to the point where earnings growth will exceed that which was attainable by the pre-merger company. Synergies, such as those mentioned above, are the reason that acquiring companies can offer premiums over pre-announcement stock prices and still anticipate that the acquisition will be accretive to earnings and add shareholder value. Otherwise, acquisitions at premiums would not be economically feasible. While the circumstances described above apply directly to target companies that have agreed to be acquired, similar expectations are reflected in the stock prices of other gas utilities that represent potential candidates for acquisition. That is to say, the stock prices of many gas utilities include some expectation that they may become the target of a takeover during the consolidation of the industry. Stated another way, many gas company stocks reflect some expectation related to M&A activity, just as a rising tide lifts all boats.

Q. What would be the DCF result based upon Mr. Draper's calculations after eliminating the three companies that you identified above?

A. As shown on Composite Exhibit No. PRM No. 3, Schedule 3, I have eliminated CTG Resources, Providence Energy, and Southwest Gas from the Value Line group used by Mr. Draper. There, the DCF return is 10.97%. Hence, the change in the composition of the group has a significant impact on the final results. Indeed, the cost of equity increases by 0.69% (10.97% - 10.28%) when the companies subject to M&A are removed.

Q. Do you have any general comments concerning the DCF method?

A. In order for an analyst to properly apply the DCF method, he/she must be sensitive to a particular company's capital needs, risk profile, and credit quality. Failure to consider these important factors will be unfair to the utility and will lead to a higher future cost of capital (both debt and equity). This is because the cost of capital, like other items of revenues, expenses and investment, must be reflective of the risks which will prevail during the effective period of the new rates. If the DCF approach cannot cope with general capital market fundamentals, then either the assumptions underlying the DCF method are incomplete or the approach is not being properly implemented. The DCF model is useful in measuring the cost of equity, but only in conjunction with other methods. The investment community uses the DCF model and other models in its analysis of common stocks. Likewise, many regulators typically review the results of multiple methods. Moreover, in response to the NARUC survey, this Commission indicated that all methods are considered, (see, for example, Utility Regulatory Policy in the United States and Canada 1994-95).

Q. What form of the DCF model is typically employed in public utility ratesetting?

A. The constant growth or "Gordon" form of the DCF model is typically used in public utility ratesetting. In both the Gordon and other forms of the DCF, there is an element of circularity in the DCF model when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. Therefore, the use of the DCF in rate cases ensures that regulators will continue to provide high growth companies with a return which sustains that performance. On the other hand, the use of the DCF for low growth companies perpetuates that performance and hinders any improvement. Due to this circularity, the DCF model may not fully reflect the true risk of a regulated firm.

Q. Please describe Staff's DCF model.

A. Mr. Draper has used a DCF model that is based generally upon specific cash flows representing dividend amounts for the next four years plus a terminal cash flow that includes the dividends in the fifth year plus the selling price of the stock, (i.e., the liquidation dividend). From those specific cash flows, Mr. Draper used an internal rate of return ("IRR") approach to produce his DCF result.

Q. Are there shortcomings associated with the implementation of this model?

A. There are shortcomings inherent in the application of all models that attempt to represent complex expectations of investors. As to the Staff model, the liquidating dividend represents the capitalized value (i.e., price of the stock) of the terminal year dividend which is determined from the resulting cost of equity. This involves an iterative process where an input is a function of result. That dividend in the fifth year has been capitalized at the dividend yield ("D/P") that has been assumed from the cost of equity less the long-term growth rate. The analysis is substantially influenced by the (i) the return on equity forecast by Value Line, (ii) the dividend payout ratio that is revealed by the relationship of Value Line's forecast of earnings per share and dividends per share in the terminal year, and (iii) the implied market-to-book value ratio.

Q. Can you show how these factors are interrelated in Staff's cash flow analysis?

A. Staff's cash flow analysis is essentially equivalent to the retention growth representation of the DCF model. Unfortunately, this form of the DCF mixes accounting returns and market returns in the following manner:

$$\begin{array}{r} \mathbf{E/B} \\ \mathbf{-D/B} \\ \underline{\mathbf{+D/P}} \\ \underline{\underline{\mathbf{ROE}}} \end{array}$$

where:
E = earnings per share
D = dividend per share
B = book value per share
P = price per share
ROE = return on equity

The retention growth form of the DCF does not adequately reflect investor expectations of total returns. Since retention growth is intended to describe growth in book value, this method is inappropriate because investors do not necessarily realize growth in the value of their investment at the retention growth rate because utility share prices do not always trade at a constant multiple of book value. I have listed some of the other factors which contribute to earnings growth that are not accounted for by the retention growth approach (see Composite Exhibit No. PRM-2, Appendix E, page E-10).

Q. Can you demonstrate how this has occurred?

A. Essentially, there are three inputs necessary to solve for the results of the Staff's DCF model. Those are: (i) an assumed return on book common equity ("E/B"), (ii) an assumed dividend payout ratio ("D/E"), and (iii) an assumed market-to-book ratio ("P/B"). For the Natural Gas Distribution Companies, those inputs are: E/B = 12.80%, D/E = .559, and P/B = 1.543. The resulting DCF return, expressed with these values, is:

$$E/B \quad - \quad D/B \quad + \quad D/P \quad = \quad k$$

$$12.80\% - (12.80\% \times .559) + (12.80\% \times .559) \div 1.543) = 10.28\%$$

As can be seen from the expression above, the assumed return on book value ("E/B") represents a key component of each term in the Staff's DCF analysis. The E/B is dependent upon the forecast of a single Value Line analyst. A similar representation of the DCF analysis for the Electric Utilities is:

$$E/B \quad - \quad D/B \quad + \quad D/P \quad = \quad k$$

$$13.55\% - (13.55\% \times .544) + (13.55\% \times .544) \div 1.552) = 10.93\%$$

Another problem with the approach involves the Value Line forecast of E/B which is based upon year-end book values. This results in a downward bias because an average book value should be used that produces a higher E/B value. The method to convert the year-end equity return to the average equity return involves the formula 2(1+G)/(2+G).

Q. What would the 12.80% ROE forecast by Value Line become with the conversion from year-end to average book values?

A. The forecast return on book common equity must be adjusted by the growth in common equity for the period to derive an average yearly return. The average yearly return ("E/B") is thus 13.1516% rather than 12.8%, as shown on Composite Exhibit No. PRM-3, Schedule 4. The resulting cost of equity would be 10.42%

Q. What are the results of the Staff's model if the return on average book value was included for the natural gas distribution group when CTG Resources, Providence Energy, and Southwest Gas were removed?

A. Those results are shown on Composite Exhibit No. PRM-3, Schedule 5. There, the cost of equity is shown to be 11.11%.

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

A. The theory of DCF indicates that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth which is the basis for the capital gains yield and the source of dividend payments must be given primary emphasis.

Q. Are there other reasons that earnings growth should be emphasized?

A. Yes. Earnings per share growth is the primary determinant of investor expectations concerning their total returns in the stock market. The capital gains yields (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases and the individual whose name is most commonly associated with the DCF model, has determined that the best measure of growth in the DCF model is analysts' forecasted earnings per share growth[1]. Hence, to follow Professor Gordon's findings, earnings per share forecasts must be given primary weight.

On Composite Exhibit No. PRM-3, Schedule 6, I have provided the forecasts of earnings per share from I/B/E/S, Zacks, First Call, and Value Line. The I/B/E/S, Zacks, and First Call growth rates are consensus forecasts taken from a survey of analysis that make projections of growth for these companies. The Zacks and First Call estimates are obtained from the Internet and are widely available to investors, free-of-charge. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The I/B/E/S forecasts can be obtained by subscription, or through the S&P Earnings Guide -- the source I have used in this case. As shown by the data contained on Composite Exhibit No. PRM-3, Schedule 6, the average earnings per share growth rate forecast is 6.36% for Mr. Draper's proxy group.

Q. Have other regulatory agencies employed forecasts of earnings per share growth in a multi-stage DCF?

A. Yes. The Federal Energy Regulatory Commission ("FERC") has used a form of the DCF that includes multiple growth rates. These growth rates are then weighted and used in the simplified

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

constant growth DCF model (i.e., the Gordon model). The FERC has evolved its approach in natural gas pipeline orders, including Northwest (79 FERC ¶61,309) Williston Basin (79 FERC ¶61,311), and Transco (84 FERC ¶61,084). FERC began its transition from single to two-stage growth rates in 1994, with its Ozark (68 FERC ¶61,032) decision.

Q. How has the FERC weighted the two growth rates that is considered important?

A. The FERC has assigned two-thirds (66.7%) weight to the analysts' forecasts of earnings per share growth and one-third (33.3%) weight to long-term growth. The FERC has used economy wide measures for gauging long-term growth. The reasons given by the FERC for this process were:

- As companies reach maturity over the long-term, their growth slows and their growth rate approaches that of the economy as a whole.
- Over the long run, it is reasonable to expect that a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it during bad periods.
- The purpose of using the DCF analysis is to approximate the rate of return an investor would reasonably expect from a pipeline company, and that the long-term growth of the economy was used by two large investment houses in conducting the DCF analysis for investment purposes.
- Witnesses have used long-term growth of the economy as a whole as confirmation or support for their own analysis.

Q. How would you propose to incorporate long-term growth into a two stage DCF analysis?

A. I propose the use of consensus forecasts of long-term growth that are widely available to investors which would have an influence on the stock prices. In this regard, I propose that the long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as one source of the second-step growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted expert economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon a narrow sample, or a single source of a forecast. Blue Chip contributors include Bear Stearns, Goldman Sachs, First Union, J.P. Morgan WEFA, Merrill Lynch, Prudential Securities, Moody's and Standard & Poor's. Indeed, Blue Chip is frequently quoted in "The Wall Street Journal," "The New York Times," "Fortune," "Forbes," and "Business Week."

Q. What are the Blue Chip forecasts?

A. The March 10, 2000 Blue Chip long-term forecasts were: 3.1% in real GDP growth; 2.1% in the GDP deflator; 5.2% in nominal GDP growth; and 5.6% in corporate profits (pre-tax). These forecasts are part of an eleven-year horizon.

Q. Are you aware of other respected surveys of economic growth?

A. Yes. The Federal Reserve Bank of Philadelphia's Research Department conducts a quarterly survey of forecasts of economic variables prepared by private sector economists. Philadelphia Fed's "The Survey of Professional Forecasters" is a successor to an earlier survey that was begun in 1968 by the American Statistical Association and the National Bureau of Economic Research. Annually, the Philadelphia Fed's survey compiles long-term, defined as 10-years, forecasts of real GDP growth, inflation, and other economic and financial variables. Although this survey maintains the anonymity of the contributors, the 36 participants were from Wall Street financial firms (13 contributors), banks (8 contributors), economic consulting firms (5 contributors), university research centers (3 contributors), and private firms including chief economists at Fortune 500 firms (7 contributors). In its first quarter 2000 survey, the Philadelphia Fed released the following forecasts: 3.05% median and 3.097% mean for the growth in real GDP and 2.50% median and 2.506% mean for inflation as measured by the Consumer Price Index. These forecast confirm the reasonableness of the long-term Blue Chip forecasts.

Q. How have you used these data to develop the second-stage growth rate?

A. I have summarized these data on Composite Exhibit No. PRM-3, Schedule 6. On that schedule, I have provided the forecasts of GDP growth and growth in corporate profits available from Blue Chip. I have used these data along with the five year forecasts previously described. I gave two-thirds weight to the earnings per share forecasts and one-third weight to the economy wide long-term forecast. As shown on Composite Exhibit No. PRM-3, Schedule 7. I have computed the dividend yields for Mr. Draper's group using the data that he provided on Exhibit DJD-4. Finally, my Composite Exhibit No. PRM-3, Schedule 8, provides the DCF results using the dividend yields and growth rates described previously.

	Using 5.2% Second Step Growth (pages 1 and 3)	Using 5.6% Second Step Growth (pages 2 and 4)
Staff's Proxy Group	11.01%	11.14%
~~Commission's~~ Proxy Group excl. M+A	11.55%	11.69%

Q. Mr. Draper has also used the CAPM to measure the cost of equity. Have you detected any problems with his application of this model?

A. I have detected two potential problems with his application of the CAPM. First, and most importantly, the 11.89% total market return used by Mr. Draper is entirely too low. Second, Mr. Draper made no provision in the CAPM for flotation costs.

Q. Please address the issue of the total market return.

A. Focusing principally upon forecasts of the total return that could be expected for the future, Zacks and Value Line provide valuable evidence of the type of returns that investors could expect for the future. In this regard, Composite Exhibit No. PRM-3, Schedule 9 shows the inputs available from Value Line. According to the September 1, 2000 edition of Value Line, the median total return that could be expected from the 1,700 stocks that it follows would be:

	Dividend Yield		Appreciation Potential		Total Market Return
September 1, 2000	2.2%	+	15.8%[2]	=	18.0%

Supplementing this return, Zacks forecasts that the five-year earnings per share growth rate is 12.1% for the S&P 500. Using the average July 2000 dividend yield for the S&P 500 of 1.13% (16.11 ÷ 1465.70), the DCF cost rate for the S&P 500 is:

$$D_0/P_0 \quad (1 + .5g) \quad + \quad g \quad = \quad k$$

$$1.10\% \quad (1.0605) \quad + \quad 12.1\% \quad = \quad 13.3\%$$

Q. What total market return would you propose in the CAPM?

A. Using the Zacks and Value Line sources, the total market return that I propose would be 15.65% (18.0% + 13.3% = 31.3% ÷ 2). This return is reasonable in today's market given the actual performance of the S&P 500 over the past several years, whereby the total return has been: 21.04% in 1999, 28.58% in 1998, 33.36% in 1997, 23.07% in 1996, and 34.43% in 1995.

Q. What CAPM cost rate have you calculated with a 15.65% total market return?

A. The CAPM cost rate would be:

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[2] The estimated median price appreciation potential is forecast to be 80% for 3 to 5 years hence. The annual capital gains yield measured at the 4-year midpoint of the forecast is 15.8% ($1.80^{.25}$ - 1).

$$Rf \quad + \beta \quad (Rm - Rf) \quad = \quad k$$

$$6.02\% \; + .60 \; (15.65\% - 6.02\%) = 11.80\%$$

An adjustment for flotation costs would increase this return.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. In my opinion, the equity return recommended by Mr. Draper should be increased. My calculation of the DCF returns provides costs rates of 11.01% to 11.69%. I would urge the Commission to focus on the returns after excluding the results for M&A take over targets. Those DCF results would be 11.55% to 11.69%. The CAPM cost rate is 11.80%. As such a reasonable cost of equity would be 11.75% prior to adjusting for the Florida Division's higher risk profile. Those adjustments would include 37 basis points for the Florida Division's smaller size and 65 basis points for competitive risks which would increase the cost of equity by about one percentage point (1.00%) according to Mr. Draper. These risk adjustments would therefore produce a 12.75% (11.75% + 1.00%) cost of equity for the Florida Division which is close to the 13.0% that I recommended for the Company in my direct testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CHAIRMAN DEASON: Does that complete the record in this proceeding?

MR. SCHIEFELBEIN: I believe, it does.

MR. ELIAS: Yes.

CHAIRMAN DEASON: Okay. Then, if there are any witnesses present here today, they can be excused.

MR. SCHIEFELBEIN: Thank you.

CHAIRMAN DEASON: We will hear no live testimony in this proceeding. The record is now complete with testimony.

I propose that we just come back at 2:00. And you can do the calculations and check them and, hopefully, there will be no errors, and we can take that up at 2:00 this afternoon. Commissioners, 2:00?

COMMISSIONER JACOBS: Sounds fine.

CHAIRMAN DEASON: Fine?

MR. ELIAS: As soon as we have those done, we will distribute them to you so that you get a chance to study them before you come back.

CHAIRMAN DEASON: That will be helpful.

MR. ELIAS: And to the company as well.

CHAIRMAN DEASON: Okay. We will stand in recess until 2:00.

(Brief recess.)

CHAIRMAN DEASON: Call the hearing back to order.

Mr. Elias.

MR. ELIAS: Thank you, Mr. Chairman.

Commissioners, you should have received, we've shared with the company, and I've provided a copy to the court reporter, also, several schedules which reflect the agreements that are in the prehearing order as well as the positions that were agreed to this morning.

For the sake of clarity, I'd ask that this be assigned an exhibit number, which I believe the next one would be Exhibit 10.

CHAIRMAN DEASON: I believe, it's 11; is it not? Was 10 the rebuttal exhibit?

MR. ELIAS: I'm sorry. Then, the next exhibit number.

CHAIRMAN DEASON: Exhibit 11.

(Exhibit 11 marked for identification and admitted into the record.)

MR. ELIAS: And we're prepared to go issue by issue, answer specific questions, or in whatever other fashion you deem appropriate.

CHAIRMAN DEASON: Okay. First of all, let me ask, has the company had an opportunity to review these schedules?

MR. SCHIEFELBEIN: Yes, sir, we have.

CHAIRMAN DEASON: Is there any disagreement?

MR. SCHIEFELBEIN: No, sir.

CHAIRMAN DEASON: Commissioners, questions?

Well, the revenue deficiency, as calculated on Attachment 5, this is 1.251 million. Now, is this the amount upon which we will utilize the projected billion determinants to come up with the rates; is that correct?

MR. WHEELER: Yes. What we will do is combine the revenues at present rates without the adjustment for the lost customers and add this increased number. And that will be the total revenue requirement over which the rates will be designed to recover.

CHAIRMAN DEASON: And it would be calculated using billing determinants based upon the forecasted -- well, the actual loss and forecasted loss of two large customers?

MR. WHEELER: Right. The billing determinants will be adjusted downward to reflect the loss of the customers.

CHAIRMAN DEASON: Okay. And everyone is in agreement that even doing that, there will be no rate increase for any customer class which exceeds that which was noticed as a potential rate increase. The rates are as noticed with the filing; is that correct?

MR. SCHIEFELBEIN: Yes, sir.

CHAIRMAN DEASON: The company acknowledges that. That's Staff's understanding as well.

MR. WHEELER: Yes.

CHAIRMAN DEASON: Okay. I had one question on the capital structure. I think, there was an equity ratio of 50 -- was it 54%?

MR. LESTER: Yes, sir, 54.06.

CHAIRMAN DEASON: Okay. How does that compare with other gas companies under our jurisdiction?

MR. LESTER: I think, they're right there. I think, People's Gas is about 56 or 7, City is about 42. Florida Public is a little higher than that. I believe, it's reasonable for, you know, for Florida companies, the 54 level. It's reasonable within the Standard & Poor's benchmarks. Even though this company doesn't have a bond rating, we kind of use those benchmarks as a comparison.

CHAIRMAN DEASON: Okay. Can you show me where, as part of the stipulation that was agreed to, there would be a $30,000 reduction in expenses? This is A&G as well as O&M expenses? Where is this reflected or is it a combination?

MS. MERTA: That would be on the NOI Schedule.

CHAIRMAN DEASON: Okay. Could you point me --

MS. MERTA: I think, it's the very last adjustment there. Let me find it.

CHAIRMAN DEASON: Attachment 3; is that correct?

MS. MERTA: That's schedule -- Attachment 3, Page 1 of 2 under --

CHAIRMAN DEASON: It is a line item, correct? You've made that adjustment?

MS. MERTA: Yes, sir. It's adjustment number 56, the very last one, O&M there, expenses related to lost customers.

CHAIRMAN DEASON: Okay. I guess, my question is that how is this -- how will this be recognized for surveillance purposes? Will this, like, be an ongoing adjustment or did you break it down by account or will it be part of surveillance? What's Staff's intention?

MS. MERTA: I expect it will be part of surveillance. I have broken it down. I've just estimated amounts for our trend schedule that's attached here, but the company would certainly make this adjustment on their brain surveillance reports.

MR. MAILHOT: I think, on the surveillance report the actual expense will be whatever it is. This $30,000 is an estimate of, theoretically, lost expenses. So, say, during the coming year 2000, expenses will be whatever they are.

CHAIRMAN DEASON: So, there will not be an ongoing necessity to adjust this, it will be whatever the expenses are; is that correct?

MR. MAILHOT: That's correct.

CHAIRMAN DEASON: But the anticipation will be the actual expenses will reflect cost savings. We can't -- 30,000 is an estimate at this point, but they will be whatever they will be.

MR. MAILHOT: That's correct.

COMMISSIONER JABER: What about for revenues, then? Part of the stipulation was that you would include the amount of revenues associated with those lost customers. That's an estimate, too, correct?

MR. MAILHOT: That's correct. And what will happen is in the next year, you know, if those customers are lost, the actual revenues will be whatever they are. There will not be any adjustment on the surveillance report for that.

CHAIRMAN DEASON: And Staff is in agreement with the company's willingness and indication that if they seek a limited proceeding, that whatever rates that will become effective out of that would be delayed for at least 12 months after the effective date of these rates. Staff's in agreement with that?

MR. DEVLIN: Yes.

CHAIRMAN DEASON: Okay. Any further questions?

COMMISSIONER JABER: No.

COMMISSIONER JACOBS: No, I don't have any.

CHAIRMAN DEASON: Can I have a motion?

COMMISSIONER JABER: What is it we need to do, Staff? Do we need to move every stipulation that was offered by the utility?

MR. ELIAS: Move the adoption of Staff's recommended dispositions of the issues as shown in the prehearing order as modified by the changes that were reflected on the transcript this morning and in these schedules.

CHAIRMAN DEASON: And the bottom line, the effect of all of those stipulations, including those entered into today, are all reflected within Exhibit 11.

MR. ELIAS: Yes.

CHAIRMAN DEASON: Including all of the fallout issues?

MR. ELIAS: Yes.

COMMISSIONER JABER: I can so move, Mr. Chairman.

COMMISSIONER JACOBS: Seconded.

CHAIRMAN DEASON: It's moved and seconded. All in favor, say aye.

Aye.

COMMISSIONER JACOBS: Aye.

COMMISSIONER JABER: Aye.

CHAIRMAN DEASON: Show, then, that that motion is approved unanimously. I think, there's nothing to come before the Commission at this time, correct?

MR. ELIAS: That's correct. We will bring a recommendation to the November 7th Agenda Conference reflecting the final rates resulting from this revenue requirement.

CHAIRMAN DEASON: And there will not be the need to issue anything PAA. Those will be the final rates.

MR. ELIAS: No, that will be final. As a matter of fact, my thought was that we will do one order a couple of days after the November 7th Agenda Conference so that, you know, there will be one order that reflects the entire decision.

CHAIRMAN DEASON: Okay. Mr. Schiefelbein, anything else?

MR. SCHIEFELBEIN: Would we be correct in assuming that the rates would become effective, then, 30 days after your vote on November 7th?

MR. ELIAS: That would be, typically, what we would do, and I wouldn't see any reason for us to deviate from that, in this case.

CHAIRMAN DEASON: I think, that's the intent.

MR. SCHIEFELBEIN: Understood.

CHAIRMAN DEASON: Okay. And it will be 30 days from the vote, which is scheduled for November the 7th. And, I believe, Staff counsel has indicated that he'll be getting an order out shortly after the vote on this. So, there's no need to go over any other scheduling for briefs or anything, since there will be no briefs.

Staff, do you anticipate you'll be able to file your recommendation at the normal scheduling time for the November the 7th, 12 days prior to the 7th?

MR. ELIAS: Yes.

CHAIRMAN DEASON: Okay, very good.

Having nothing else to come before the Commission at this time, this hearing is adjourned. Thank you all.

MR. SCHIEFELBEIN: Thank you.

(Hearing concluded at 2:15 p.m.)

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, KORETTA E. STANFORD, RPR, Official FPSC Commission Reporter, do hereby certify that the Hearing in Docket Number 000108-GU was heard by the Florida Public Service Commission at the time and place herein stated.

It is further certified that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 116 pages, Volume 2, constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 28th DAY OF OCTOBER, 2000

Koretta E. Stanford

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