BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED DIRECT TESTIMONY
Of
MICHAEL J. MORLEY

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO.

Q. Please state your name, position and address.

A. Michael J. Morley, Director, Financial Accounting, AGL Services Company. My business address is 10 Peachtree Place, Location 1180, Atlanta, Georgia 30309.

Q. Have you provided a summary of your educational background and professional experience?

A. Yes. They are included as Attachment A.

Q. Have you previously submitted testimony before the Tennessee Regulatory Authority or any other regulatory commission?

A. No.

Q. What is the subject of your testimony?

A. I will present various financial and accounting data in support of Chattanooga Gas Company's ("Chattanooga" or the "Company") filing in this proceeding, including (A) the proposed revenue adjustment required for the Company's proposed rate of return, (B) Chattanooga's cost of service, (C) the determination of the rate base, and (D) the capital structure and cost of debt financing.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring the following exhibits in support of Chattanooga's revenue requirement for the twelve month attrition period ending June 30, 2005:

- Exhibit MJM-1 – Chattanooga's statement of income before and after the proposed rate adjustment and calculations of the proposed revenue adjustment, revenue conversion factor and Tennessee excise and federal income taxes.
- Exhibit MJM-2 – cost of service study for the test period and attrition period, including pro-forma adjustments and explanations for the pro-forma adjustments.
- MJM-3 – the elements of rate base estimated as of June 30, 2005.
- MJM-4 – a summary of the Company's estimated cost of capital as of June 30, 2005.

Q. What is the historic test period in support of the Company's case?

A. The Company's test period is the twelve months ended September 30, 2003. This represented the most recent financial data available when preparing the Company's case.

Q. Were these exhibits and related schedules prepared by you or under your direction and supervision?

A. Yes.

A. CALCULATION OF REVENUE REQUIREMENT

Q. Would you summarize the information contained in Exhibit MJM-1, supporting the Company's calculated revenue requirement?

A. Schedule 1 reflects the attrition period revenue deficiency and proposed rate adjustment necessary to allow the Company the opportunity to earn a fair and reasonable return on its investment. Column 1 provides an income statement for the attrition period, including pro-forma adjustments; Column 2 provides the Company's proposed rate adjustment; and Column 3 provides an income statement for the attrition period after the Company's proposed rate adjustment. Additionally, Line 17 of Schedule 1 includes the calculated rate of return of 5.95% before the proposed rate adjustment. Schedule 2 of Exhibit MJM-1 provides the calculation of the proposed revenue adjustment in the amount of $4,560,699 required for the Company's proposed rate of return of 8.84%. This calculation is based on the Company's anticipated gross revenue conversion factor, as calculated on Schedule 3 of Exhibit MJM-1. Schedule 4 of the Exhibit provides the calculation of the Tennessee excise and federal income taxes before and after the proposed rate adjustment.

Q. How were the amounts for cost of service, rate base and rate of return derived in Exhibit MJM-1?

A. Amounts for the Company's estimated cost of service, estimated rate base and rate of return were calculated using budgeted and forecasted data available for the attrition period. This data includes operating expenses, capital expenditures, depreciation expense, lead lag study, interest expense, income taxes and average debt balances by debt classification.

B. COST OF SERVICE

Q. Mr. Morley, please describe the content of Exhibit MJM-2 supporting the Company's cost of service filing.

A. Schedule 1 of Exhibit MJM-2 provides comparative pro-forma income statements for the test period and the attrition period. Schedule 2 of the Exhibit provides a comparative pro-forma detail of operation and maintenance expense and taxes other than income by major category for both periods.

Q. Please describe the adjustments necessary to the test period and the attrition period to develop the pro-forma schedules.

A. Schedule 3 provides the unadjusted statements of income for the test period (as reported in the company's financial records) and attrition period (as budgeted and forecasted for financial purposes) and includes the pro-forma adjustments that were made to arrive at the comparative pro-forma income statements provided in Schedule 1 of Exhibit MJM-2. Schedule 4 provides a brief explanation as to the nature and amount of the pro forma adjustments included in Schedule 3.

Q. What are the purposes of these schedules?

A. Schedules 1 and 2 were created to provide a quick and easy comparison of the changes between the test period and the attrition period and Schedules 3 and 4 provide the impact of the pro-forma adjustments on the unadjusted test period and attrition period income statements.

Q. Why were the pro-forma adjustments necessary, and what was the basis for the adjustments?

A. For the test period, the pro-forma adjustments were made to exclude one time items, to exclude accounting true-ups or adjustments that applied to a different period and to include or exclude items that were also being adjusted from the attrition period. Adjustments for the attrition period were the result of a full review of the attrition period budget and forecast. Adjustments were also made to provide consistent regulatory treatment with previous rate proceedings.

Q. Please give an example of an adjustment required after the budget and forecast review.

A. One example is the adjustment to reduce property tax expense by $332,241. When the attrition period budget and forecast was prepared, property tax expense was based on historical assessments and county equalization and tax rates. While the Company was aware of a decrease in the county equalization rate for 2003, the amount of the decrease was not known. The Company recently received the 2003 assessed value based on the reduced equalization rates, which resulted in a substantial decrease in the expense.

Q. Please explain adjustments required for consistent regulatory treatment?

A. The Company has historically recovered pension expense through rates based on estimated contributions to the Company pension plan. For financial reporting (and budgeting and forecasting), the Company reports pension expense in accordance with generally accepted accounting principles ("GAAP"). Therefore, an adjustment was made to remove the GAAP related pension expense and include the regulatory accounting pension expense.

Q. Have you provided supporting work papers for the pro-forma adjustments made in the test period and attrition period?

A. Yes. They are included in Minimum Filing Guideline No. 25, which has been included as part of this proceeding.

Q. What was your basis for the attrition period budget and forecast?

A. The attrition period was based on the Company's budget and forecast for the twelve months ending June 30, 2005. Part of the normal budgeting process for AGL Resources Inc. and Subsidiaries ("AGLR") is to budget for a 12 month period and to forecast for the succeeding twelve month period. In this case, the attrition period includes the budget for July 1, 2004 – December 31, 2004 and forecast for January 2005 – June 2005. AGLR recently completed its 24 month 2004 - 2005 budget process. Therefore, budget and forecast data were available for the attrition period and used for this rate proceeding.

Q. Briefly explain the budget and forecast process itself.

A. For the twelve month budget, AGLR uses a bottoms-up, zero based budgeting approach for those expenses for which it is reasonable to do so. This approach budgets expenses with an identifiable basis, such as head count or a lease agreement, beginning at zero. For those expenses for which it is not reasonable to utilize a bottoms-up approach, growth factors are applied to the most recent available data, which normally includes actual financial data for the current fiscal year plus a year-to-go forecast. The budget is prepared by the individual department or business unit managers. These individuals are most familiar with the day to day operations of their areas and best equipped to estimate the costs associated with managing their departments or business units.

Q. Does the process for forecasting the subsequent 12 months differ from the budgeting process?

A. For the most part, the process does not differ. The forecast is based more on a growth factor, but it is also based on the budgeted data. In this instance, the 2005 forecast was based on the 2004 budget. Additionally, there are parameters and growth factors distributed to budget managers during the budget process for large expense items, such as payroll, for both the budget and forecast periods.

Q. What are examples of expenses budgeted using the bottoms-up approach?

A. Expenses in which the bottoms-up approach is typically used include, but are not limited to, payroll, building leases, pensions and post retirement benefits, depreciation expense and bad debt expense. These expenses have an identifiable basis and driver to develop a budget, beginning at zero. For example, payroll is budgeted based on actual employee wage and salary levels. Estimated overtime and capitalization factors are then applied to arrive at total payroll expense. Another example is depreciation expense, which is based on the cost basis of existing plant plus expected capital expenditures applied to the applicable depreciation rates.

Q. What are examples of expenses budgeted and forecasted using growth factors or historical trends?

A. Expenses that are budgeted and forecasted using growth factors include, but are not limited to, certain maintenance and distribution expenses and general and administrative expenses. These costs are in a number of accounts, have a high volume of invoices and do not have a definitive basis or driver to efficiently develop a budget. Utilization of a bottoms-up approach would not be practical for these type expenses.

Q. Who reviews and approves the budget and forecast?

A. The budget is first reviewed and approved by the Policy Committee of AGLR, which consists of the CEO, CFO, General Counsel, Executive Vice President of Distribution Operations and Senior Vice President of Business Support. Once approved by the Policy Committee, the budget is presented to the Board of Directors of AGLR. The forecast has not been formally reviewed by the Policy Committee and has not been presented to the Board of Directors (the "Board").

Q. Has the 2004 budget been presented to and approved by the Board of Directors?

A. The budget has been presented to the Board of Directors for approval. The Board requested additional review on certain expenses and capital expenditures prior to a resolution approving the 2004 budget. However, based on discussions with members of the Policy Committee, the 2004 income statement and capital expenditure budget for Chattanooga should not be impacted by the Board's request.

Q. Did you review the attrition period budget and forecast as part of the cost of service study?

A. Yes.

Q. How was this review process done?

A. Operating expenses were projected through December 31, 2003 using actual financial data through November 30, 2003 and the forecast for the month of

December, adjusted for one time non-recurring items. This was used as a baseline for projecting the attrition period operating expenses and then compared to the budget and forecast for reasonableness.

Q. How was the December 31, 2003 baseline projected for the reasonableness test?

A. With the exception of payroll, a growth factor of 2% was used to increase most expenses incrementally in 2004 and 2005. The 2% growth factor represents the approved inflation factor used during the 2004-2005 budgeting process. This growth factor is also consistent with the national average increase in the Consumer Price Index from 2001 – 2003. For payroll, a growth factor of 2.5% was used for estimated merit increases. While the actual growth factor used in the preparation of the budget and forecast for exempt and non-exempt employees was 2% and 2.5 %, respectively, non-exempt employees comprise approximately 80% of the total payroll budget for Chattanooga. Therefore, use of 2.5% was deemed appropriate.

Q. Which expenses were not projected using a 2% growth factor for the reasonableness test?

A. Employee benefits, depreciation, AGL Services Company allocations, capitalized expenses and taxes other than income were analyzed based on specific growth factors, assumptions or known circumstances for each expense.

Q. Have you provided the work papers supporting this reasonableness test?

A. Yes. They are included in Minimum Filing Guideline No. 43, which has been filed as part of this proceeding.

Q. Explain the increases between the test period and the attrition period on Schedule 2.

A. The increase in payroll expense of $412,004 is primarily driven by an increase in the number of employees between the test period and the attrition period. Head count for the test period increased from 46 in October 2002 to 56 in September 2003. This number decreased to 54 in December 2003. However, the Company intends to replace the two open positions prior to the start of the attrition period - July 1, 2004. The payroll expense also includes a 2% increase in pay for exempt employees and 2.5% increase for non-exempt employees in 2004 and 2005, resulting in an increase of approximately $90,000. Additionally, there was an increase as a result of a change in the mix of exempt employees and associated pay scales, resulting in an increase of approximately $20,000.

Q. Please continue.

A. The increase in bad debt expense of $375,835 is the result of a higher net charge-off percentage used for the attrition period than the actual charge-off percentage for the test period. The Company used a three year average for the attrition period (October 2000 – September 2003), resulting in a net charge-off percent of 1.0121%. The actual charge off percent for the twelve month test period was 0.6232%.

Q. Will the outcome of Docket No. 03-00209, "Petition for a Declaratory Ruling regarding the Collectibility of the Gas Cost Portion of Uncollectible Accounts under the Purchase Gas Adjustment ("PGA") Rules" have an impact on the Company's bad debt expense?

A. Yes. If the Company receives a favorable Declaratory Ruling, the proposed rate adjustment will decrease by approximately $640,000, which represents the gas cost portion of bad debt expense in the attrition period.

Q. Please explain the increase in distribution expenses.

A. The increase in distribution expenses is due to a Federal Energy Regulatory Commission ("FERC") mandated pipeline integrity program. The estimated cost of the program during the attrition period is $261,432. Richard Lonn provides an explanation of the requirements and purpose of this program in his testimony.

Q. What are "AGL Services Company Allocations"?

A. In October 2000, AGLR became subject to the Public Utility Holding Company Act ("PUHCA" or the "Act") of 1935. In general, the Act was passed to prevent utility holding companies from subsidizing unregulated business activities from profits obtained from their regulated business activities and customers. Additionally, PUHCA restricts public utilities from providing services to one another and requires the maintenance of all accounting procedures, correspondence, memorandum, papers, books and other records in a manner in which such records are auditable. In accordance with the Act, AGLR formed AGL Services Company ("AGSC") to provide shared services to all subsidiaries of AGLR at actual cost. AGSC allocations are the costs for services performed by AGSC employees on behalf and in support of Chattanooga operations. These costs are commonly referred to as allocated costs or charge backs.

Q. Is AGLR in compliance with the above mentioned PUHCA requirements?

A. Yes.

Q. What types of service does AGSC provide to Chattanooga?

A. Services provided by AGSC to Chattanooga are included in Minimum Filing Guideline No. 46, which is included with this filing.

Q. How do the services and related costs provided by AGSC benefit the Chattanooga customer?

A. In today's highly competitive business environment, companies strive to improve efficiencies and reduce costs through synergies and economies of scale while at the same time improving the services provided to customers. This is often achieved by identifying and consolidating those functions that are common in nature with no variation from one affiliated company to the next. Examples of these type functions include payroll, accounts payable and receivable, general accounting, treasury, human resources and most information systems support. There are also those functions that may differ in some instances, but for the most part have a common foundation from which to leverage resources. Examples of these type functions include rates and regulatory compliance, legal support, gas supply and capacity management and customer services. Consolidation of these functions and services into one area or company, in this case AGSC, not only provides a cost savings benefit, but also provides improved customer service and achieves a better, more sound infrastructure for customers to use. These latter two benefits are achieved through a larger and more talented resource pool from which Chattanooga can use at its discretion as an affiliate of AGSC.

Q. How are the allocated costs charged to Chattanooga determined?

A. **In summary, AGSC's total operating expenses are charged back, at cost, to AGLR subsidiaries in three components:**

1. **Direct Charge** – Direct charge costs are allocated to AGLR subsidiaries based on a driver and standard rate. These costs include fleet services, facilities, certain benefit costs, information services and technology and gas supply and capacity management;
2. **Direct Assignment** – AGSC's remaining costs (total operating expenses net of direct charges) are charged back based upon the percentage of time spent by AGSC employees providing services to the Company and the other AGLR subsidiaries. This time is tracked through time card reporting; and
3. **Allocation** – AGSC's remaining costs (total operating expenses net of direct charges and direct assignments) are charged back based upon certain allocation drivers. These remaining costs are associated with unassigned time or time spent providing internal AGSC services.

Q. Why did the AGL Services Company Allocations increase over the attrition period?

A. The increase of $200,165, or 2.89%, in AGSC allocated costs is due to a comparable increase in total allocable expenses at AGSC of 2.85%. Additionally, costs allocated to Chattanooga by AGSC as a percentage of total allocable expenses at AGSC for the test period and attrition period are 5.04% and 5.05 %, respectively. The allocable expenses of AGSC used for comparison purposes exclude corporate costs directly allocated to AGLR. Increased costs at AGSC were primarily related to information services and technology initiatives and an increase in costs for legal support.

Q. What caused the increase in gross receipts tax?

A. The gross receipts tax increased by $166,247 as a result of an increase in the Company's budgeted and forecasted gross revenues. The gross receipts tax was calculated based on the budgeted and forecasted gross revenues before pro forma adjustments. The gross receipts tax was reduced by $22,765 as a result of the pro forma adjustments to reduce revenue and an estimated proposed rate adjustment.

C. DETERMINATION OF RATE BASE

Q. How did you determine the average rate base?

A. The average rate base, which is provided in detail in Schedule 1 of Exhibit MJM-3, was calculated as follows:

1. Utility plant in service, construction work in progress, contributions in aid of construction and the accumulated provision for depreciation were calculated using the account balances as of December 31, 2003. These balances were then projected through the attrition period using the budget for 2004 and forecast for January – June 2005.
2. The accumulated deferred income taxes were calculated using the account balances as of December 31, 2003 and the projected change in the deferred balance through the end of the attrition period.
3. The customer advance for construction account is a fairly static account. Therefore, the balance of the account was based on a 13 month rolling

average from December 2002 - December 31, 2003 with no forecast assumptions.

4. The working capital requirement was calculated as follows:

a. The requirement for lead lag was based on a lead lag study performed by Work and Greer, P.C. This study was then updated on MJM-3 Schedule 3 for Chattanooga's proposed revenue adjustment. The report of Work and Greer, P.C. on the lead lag study is included in Exhibit MJM-3, Schedule 4.

b. The average stored gas inventory was calculated based on the storage volumes as of November 30, 2003. These balances were then projected monthly by applying the same withdrawal and injection volumes for the preceding twelve months (October 2002 – November 2003). For example, the withdrawal volumes used for February 2004 and February 2005 were the same actual volumes withdrawn in February 2003. Likewise, the injected volumes used for June 2004 and June 2005 were the same actual volumes injected in June 2003. The only departure from this methodology was that the ending storage balances at November 2004 were adjusted to agree with the ending storage balances at November 2003. Pricing for the injections was calculated using the NYMEX futures price for natural gas as of January 16, 2004. Pricing for the withdrawals was calculated using the monthly weighted average cost of gas, which was re-calculated each month based on the applicable withdrawals, injections and NYMEX futures price. Additionally, the cost of liquefaction and vaporization was included in the calculation for the LNG storage facility. The twelve month average for the attrition period (July 2004 – June 2005) was then calculated using the monthly projected balances of the stored gas inventory.

c. The deferred rate case costs represent the average balance at the end of the attrition period for the estimated external costs that have been or will be incurred in preparation, filing and completion of this proceeding. Total costs are estimated at $300,000.

d. The customer deposits and accrued interest on customer deposits were calculated using a regression analysis based on the average customer deposits and interest on customer deposits balances from September 2001 through November 2003.

e. The average reserve for uncollectible accounts was calculated using the ratio of the average historical reserve balance to the average historical revenues. The ratio was computed based on the three year period December 2000 – November 2003. This ratio was then applied to the revenues for the attrition period plus the proposed revenue adjustment.

f. The materials and supplies inventory, prepayments and other accounts receivable accounts are fairly static. Therefore, they were based on a 13 month rolling average from December 2002 – December 2003 with no forecast assumptions.

Q. Did the average rate base change between the test period and the attrition period?

A. Yes. The average rate base increased approximately $2.6 million as follows:

1. The working capital requirement increased approximately $0.9 million, primarily due to an increase in the average balance of stored gas inventory, offset by a decrease in cash requirements and other accounts receivable.
2. The net plant balance increased approximately $3.1 million, primarily due to the bare steel/cast iron pipeline replacement program, improvements to the Company's LNG facility and planned expansion of the Company's system.
3. The above two increases were offset partly by a $1.3 million increase in deferred income taxes.

Q. What will be the impact to rate base and the Company's base revenue requirement if the proposed pipeline replacement program is approved?

A. The average rate base will decrease by approximately $2.2 million, and the revenue requirement will decrease by approximately $359,000 if the Company is allowed to recover these costs through the proposed rider.

Q. What will be the impact to rate base and the Company's base revenue requirement if the Company's proposal to include carrying charges related

to stored gas are capitalized and included as part of the value of gas inventory?

A. The average rate base will decease by approximately $13.2 million, and the revenue requirement will decrease by approximately $1.7 million if the Company is allowed to capitalize these costs.

D. COST OF CAPITAL

Q. Please explain Exhibit MJM-4 supporting the Company's capital structure and proposed rate of return.

A. Schedule 1 of the exhibit provides a summary of the Company's ratio of debt components and common equity to total capitalization; Schedule 2 supports the Company's short-term debt ratio of 4.3% to total capitalization; and Schedule 3 supports the Company's long-term debt, preferred stock and common equity ratios to total capitalization at 40.10%, 8.70% and 46.90%, respectively.

Q. How were the cost rates for debt determined in Schedule 1 of MJM-4?

A. The estimated cost of short-term debt includes the cost of AGLR's projected average short-term debt balance through the attrition period. The cost of short-term debt is based on the estimated London Inter-Bank Offer Rate (LIBOR) plus an estimated spread above LIBOR. Additionally, AGLR's costs to maintain its credit faculty have been included in the cost of short-term debt. The spread is based on the estimated interest costs were Chattanooga to have a short-term financing facility in its name. Schedule 2 shows the calculation of the 4.30% short-term debt to total capitalization used in Schedule 1.

Q. How was the cost of long-term debt determined in Schedule 1 of MJM-4?

A. The cost of long-term debt includes the cost of senior notes and medium-term notes within the consolidated capital structure of AGLR. Interest costs and amortization of debt discounts, debt premiums and debt issuance costs (collectively referred to as amortization of debt costs) were projected for the attrition period. The cost projection was calculated using actual interest rates and the current monthly amortization of debt costs on existing debt. If applicable, interest rates and amortization of debt costs were estimated for new issuances of debt. The total cost of long-term debt projected for the attrition period was then divided into the projected ending debt balance at June 30, 2005, resulting in a cost rate of 6.74%.

Q. How was the cost of preferred stock determined?

A. The cost of preferred stock was calculated in the same manner as the cost for long term debt, resulting in a cost rate of 8.54%.

Q. Why was the long-term debt cost based on consolidated AGLR?

A. Chattanooga has no debt in its name and any financing needs are provided through the debt structure of the AGLR consolidated group. Additionally, use of the AGLR consolidated debt cost is consistent with the previous rate case decision for Chattanooga in Docket No. 97-00982.

Q. How was the cost of common equity determined?

A. The calculation of the cost of common equity is discussed in the direct testimony of Dr. Roger Morin.

Q. Please explain the contents of MJM-4, Schedule 2 supporting the Company's short-term debt ratio of 4.3%.

A. Schedule 2 provides the Company's estimated working capital requirement for the attrition period that will be financed using short-term debt. This working capital requirement was then divided into the Company's projected rate base for the attrition period, resulting in a 4.3% ratio of short-term debt to total capitalization.

Q. How was the working capital requirement to be financed by short-term debt estimated?

A. The Company started with the working capital requirement included in the projected attrition period rate base (MJM-4, Schedule 3). Since $9,112,615 of the stored gas inventory included in the rate base working capital requirement is considered to be financed by long-term debt, .this amount was deducted from the working capital requirement in rate base, resulting in the estimated working capital requirement that will be financed through short-term debt. $9,112,615 is the minimum amount of stored gas inventory the Company expects to maintain during the attrition period.

Q. What is the purpose of MJM-4, Schedule 3?

A. Schedule 3 of the Exhibit provides the calculation of the allocation of the remaining 95.70% capitalization to long-term debt, preferred stock and equity. The allocation of the remaining capitalization among these three components was based on a 51% to 49% debt to equity capitalization structure, excluding short-term debt.

Q. Why does the 51% to 49% capital structure exclude short-term debt and how was this capitalization structure determined?

A. The short-term debt was excluded to establish a capital structure consistent with the median capital structure of the peer group of comparable companies used in determining the Company's cost of equity. The comparable peer group was recommended by Dr. Roger Morin and is discussed in his direct testimony. The capital structure of these comparable companies is shown on Schedule RAM 9 filed in support of Dr. Morin's direct testimony.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED TESTIMONY OF
PHILIP G. BUCHANAN
ON BEHALF OF
CHATTANOOGA GAS COMPANY

DOCKET NO. ________

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

A. Philip G. Buchanan, Consultant, Rates and Regulatory, AGL Services Company. My business address is Ten Peachtree Place, Suite 1000, Atlanta, Georgia 30309.

Q. Please describe your education and professional background.

A. I received a B.S. degree in Physics in 1988 from West Georgia College. I was employed by Atlanta Gas Light Company in 1988 as a Field Service Representative. In May 1999, I transferred to the Rates and Regulatory Affairs Department as a rate analyst. I was promoted to my current position of Consultant, Rates and Regulatory in November 2000. I am responsible for supporting rate and regulatory functions for both Atlanta Gas Light Company and Chattanooga Gas Company ("Chattanooga" or the "Company").

Q. Are you sponsoring any exhibits in connection with your testimony?

A. Yes, I am sponsoring EXHIBITS PGB-1, PGB-2, PGB-3, PGB-4, PGB-5, PGB-6, PGB-7, PGB-8, PGB-9 and PGB-10. The purpose of each exhibit will be discussed in my testimony.

Q. Were these exhibits and related schedules prepared by you or under your direct supervision?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose changes to general service rate design, to support the calculation of test period and attrition period revenues, and to propose new rates to recover the attrition period revenue requirement.

Q. How is your testimony organized?

A. My testimony is organized as follows: Section 1 proposes rate design changes including a shift in the level of cost recovery from variable to fixed charges, a decrease in the number of volumetric rate blocks for residential and commercial rate classes, a change in reconnection charge rates, and a change in the commodity charge billing unit from units of volume (Ccf and Mcf) to units of energy (therms and dekatherms). Section 2 describes the process for developing Weather Normalization Adjustment (WNA) Factors for use in the WNA program and for use in adjusting test period consumption for normal weather for the residential, commercial, and multi-family housing (R-4) rate classes. Section 3 discusses the customer forecast used to determine billing units for the attrition period. Section 4 discusses the usage forecast used to determine volumes to be billed in the attrition period. Section 5 discusses the calculation of attrition period margin and revenue under current rates. Section 6 proposes rates to collect the attrition period revenue deficiency.

Q. Please define the test and attrition periods that are referred to in your testimony?

A. The test period is defined as the 12 months ended September 30, 2003. The attrition period is defined as the 12 months ending June 30, 2005.

Section 1

Q. Please outline the rate design changes included in the proposed residential class rates.

A. The Company is proposing to increase the percentage of revenues collected under the fixed customer charge, while lowering the percentage of revenues collected through the commodity, or variable charge. The Company is also proposing to lower the number of rate blocks from 3 to 2.

Q. Please outline the rate design changes included in the proposed commercial class.

A. The Company is proposing to increase the percentage of revenues collected under the fixed customer charge, while lowering the percentage of revenues collected through the commodity, or variable charge. The Company is also proposing to lower the number of rate blocks from 4 to 2.

Q. Is the Company proposing any changes to the rate design for the industrial customer classes?

A. No. The rate design for the current industrial customer classes is considered appropriate without modification. However, the Company is proposing an additional service offered as an experiment for industrial customers. The Semi-Firm Sales Service, or SF-1 tariff is detailed in the testimony of Mr. Steve Lindsey.

Q. Are there any changes to miscellaneous or "other" revenue charges?

A. Yes. The Company is proposing to increase the reconnect charge from $30 to $50 and the seasonal reconnect charge from $30 for residential customers and $45 for commercial customers to $50 for residential and commercial customers.

Q. Are there any other rate design changes?

A. Yes. The Company is proposing to bill all volumetric base charges and PGA charges in therms (for residential, commercial, and multi-family housing (R-4) classes) and dekatherms (for industrial classes), as opposed to the current practice of billing in Ccfs and Mcfs.

Q. Why are you proposing to increase the percentage of revenues collected under the fixed customer charge and to decrease the percentage of revenues collected through the commodity charge for residential and commercial classes?

A. In general, the proposed changes are designed to recover more of the fixed costs of providing delivery service through fixed charges. In operating and maintaining the distribution system, the Company incurs substantial fixed costs, which are independent of normal daily usage. Despite this fact, the Company currently recovers the bulk of its revenue requirements through variable charges. Currently, 74% of residential, multi-family housing (R-4), and commercial revenues are collected through the commodity charge, even though most of the costs incurred to serve these customers are fixed. It is more appropriate to recover fixed costs through fixed charges. Therefore, it is necessary for the fixed customer charge component of residential and commercial rates to be increased.

Q. Are there other disadvantages to recovering fixed costs through variable charges?

A. Yes. Effects from declining use per customer are exacerbated in rate designs where large portions of fixed costs are recovered through volumetric charges.

Q. Please explain.

A. Declining use per customer is a national phenomenon in the natural gas industry. Increases in appliance efficiency, reduced appliance saturation, and more efficient housing characteristics all contribute to natural gas customers using less gas annually. Bruce McDowell of the American Gas Association (AGA) stated in a presentation at the AGA Public Affairs and Marketing Forum on April 23, 2003, that weather normalized use per residential customer has declined 21% in 21 years. Mr. McDowell also stated that annual use per commercial customer levels were 140 Mcfs less in 1999 than in 1979. Chattanooga Gas Company has experienced similar trends. Weather normalized annual use per residential customer averaged 899 Ccfs in 1998. The weather normalized annual use per residential customer for the 12 month test period ending September 2003 was approximately 800 Ccfs. This indicates a decline of 11% in 5 years. Since the Company collects a large portion of its revenue through volumetric charges, declining use per customer increases the vulnerability of the Company's revenues. The Company sets rates based on a forecasted amount of usage. To the extent that this usage declines, rates do not collect the approved level of revenue. This, in turn, compels the Company to file for rate relief sooner than if use per customer was not declining.

Q. Have the effects of declining use per customer been evident in the Company's collection of revenues?

A. Yes. Although customers have been added to the system, base revenue has declined from the level approved in the last rate case. In 1998, current rates were based on 47,499 residential and 7,889 commercial customers and were designed to collect base revenues of $31.5 Million. During the 12 months ending September 2003, the Company had 50,810 residential and 8,177 commercial customers, reflecting a composite annual growth rate of 1.4% for residential and 0.7% for commercial. However, the amount of base revenue collected during the 12 months ending September 2003 declined to $30.0 Million. Much of this decline can be attributed to declining use per customer.

Q. Is the proposed change a more appropriate rate design?

A. Yes. This design change decreases the negative effects of declining use per customer and reduces pressure for the Company to file more frequent requests for rate relief.

Q. What effect would the rate design change have on residential and commercial customers' bills?

A. By shifting cost recovery from the variable component of rates to the fixed component, a greater portion of the bill is fixed. As a result, the customer's bill is less dependent on usage, and, thus, is more stable and predictable.

Q. What rates are the Company proposing for the fixed residential customer charge?

A. Chattanooga is proposing that the residential customer charge be changed to $14 during the months of November through April and remain at the current rate of $7.50 for the months of May through October.

Q. Why does the Company propose a higher fixed charge for residential customers in the winter than in the summer?

A. The majority of residential usage occurs during winter months. The impact of the rate design change is lessened by increasing the fixed charge during times of higher consumption. Lower consumption in summer months will still be reflected in low summer bills.

Q. What rates are the Company proposing for the fixed commercial customer charge?

A. The Company proposes to change the commercial customer charge to $30 during the months of November through April and to $20 during the months of May through October.

Q. **Are the proposed customer charges in line with fixed charges of other gas utilities in Tennessee?**

A. Yes. The proposed customer charge rates are comparable to those of Nashville Gas Company. Residential customer charges recently approved in Docket # 03-00313 for Nashville Gas Company are $13 during winter months and $10 during summer months. General Service customer charges approved for Nashville Gas Company are $29, $75, and $300 for small, medium, and large commercial customers respectively, with no reduction in the summer months.

Q. Why is the Company proposing to lower the number of rate blocks in the residential and commercial classes?

A. The current declining block rate design for residential and commercial customers is difficult for the customer to understand and verify on their bill. Residential usage is currently billed in 3 blocks, which change seasonally twice a year. Commercial usage is currently billed in 4 blocks, which change seasonally twice a year. The Company seeks to simplify the customer's bill by lowering the number of rate blocks.

Q. Please describe the Company's proposed change in the reconnection fee.

A. As summarized earlier, the Company proposes to adjust the reconnection fee from $30 to $50.

Q. Why is this adjustment appropriate?

A. The current charge is insufficient to offset the actual cost of reconnecting a customer. Furthermore, the customers who do not have their services disconnected subsidize the costs incurred by those customers whose service is disconnected and reconnected at a later date. Although the proposed charge of $50 does not entirely recover the cost of reconnection, it mitigates the contribution from other customers not receiving the service.

Q. Please describe the Company's proposed change in the seasonal reconnection fee.

A. The Company proposes to adjust the seasonal reconnection fee to $50 for residential and commercial customers. Currently, the seasonal reconnection fees are $30 for residential customers and $45 for commercial customers.

Q. Why is this adjustment appropriate?

A. As with the reconnection charge discussed above, the current seasonal reconnection charge is insufficient to offset the actual cost of reconnecting a customer. Furthermore, customers who turn off their service seasonally and then reactivate in the fall receive the light-up service at times of high volume of service orders, thus increasing Company overtime costs. The adjustment to the seasonal reconnection fee does not recover the entire cost of reconnection, but it more closely approximates the cost than does the current charge.

Q. Does the Company propose any other billing changes?

A. Yes. As discussed in the testimony of Mr. Steve Lindsey, the Company is proposing to bill volumetric charges in units of energy (therms and dekatherms) rather than units of volume (Ccfs and Mcfs).

Q. Is the Company proposing to bill all volumetric base and PGA charges in therms or dekatherms?

A. Yes. All usage will be measured volumetrically from the meter and multiplied by the actual BTU factor to produce usage in therms or dekatherms, with the exception of the Special Contract usage. The current terms of the Special Contract specify a rate per Mcf of usage.

Q. What BTU factor was used to convert units of volume to units of energy for the attrition period volume forecast and calculation of WNA factors?

A. The BTU factor of 1.01744 was used.

Q. How was this BTU factor calculated?

A. The BTU factor was calculated by the Gas Control department based on daily data from the test period. Daily volumetric throughput and associated BTU contents were multiplied to produce the average BTU content from each pipeline each month during the test period. The average BTU contents from each pipeline were weighted to produce monthly weighted average BTU contents. The 12 monthly BTU content factors were then averaged to produce the annual BTU factor of 1.01744. A summary of this calculation can be seen in EXHIBIT PGB-1.

<u>Section 2</u>

Q. Please describe the general process used to adjust test period usage for residential, commercial, and multi-family housing (R-4) rate classes for normal weather.

A. Usage for the residential, commercial, and multi-family housing customers is adjusted using the same methodology. First, by rate class, an actual use per customer was calculated and regressed against actual degree days to establish a relationship between usage and weather. This process produced Weather Normalization Adjustment (WNA) factors that were used to calculate monthly normalized usage for the test period.

Q. How did the Company define normal weather?

A. The National Oceanic and Atmospheric Administration (NOAA) normal degree days for the 30 year period ending 2000 were used to define normal weather.

Q. How were Weather Normalization Adjustment (WNA) factors calculated for the residential rate class?

A. Historical data of number of customers, actual throughput, actual degree days, and normal degree days were gathered by billing cycle. An average use per customer for each billing cycle was calculated using actual customers and usage. Actual use per customer was regressed against actual degree days by billing cycle to establish a relationship between usage and weather. This relationship is defined by the slope and intercept equation (Y=mX+b) where Y is usage, m is slope or Heat Sensitive Factor, X is the number of degree days, and b is intercept or Base Load. The results of this regression become the Base Load and Heat Sensitive Factors used in the process of normalizing test period usage, forecasting attrition period usage and billing the Weather Normalization Adjustment on customers' bills.

Q. Why was data at the billing cycle level used?

A. By using data at the billing cycle level, actual usage during a billing cycle is associated with the number of degree days for the same time period. This results in a more accurate measurement of the relationship between usage and weather. Also, billing cycle level data produces 252 data points for a 12 month period (21 billing cycles for 12 months) for use in the regression analysis. More data points in regression analysis result in more statistically valid results.

Q. How were the Base Load and Heat Sensitive Factor (WNA factors) used to produce monthly normalized test period usage for residential customers?

A. Normal degree days and days in billing cycle for each cycle in the test period were summed. The total degree days and days in cycle were applied to the slope and intercept equation described above to calculate a normal use per customer for each billing cycle for each month. The normal use per customer in each cycle was then multiplied by the actual number of customers in that cycle to calculate the total normalized usage for the cycle. Normalized billing cycle usage was then aggregated by relative month to produce monthly normalized usage.

Q. How were the WNA factors calculated for the commercial and multi-family housing (R-4) rate classes?

A. WNA factors for commercial and multi-family housing customers were calculated in the same manner as residential customers.

Q. How were the Base Load and Heat Sensitive Factor used to produce monthly normalized test period usage for commercial and multi-family housing customers?

A. Normalized test period usage for commercial and multi-family housing customers was calculated in the same manner as residential customers.

Q. Have the details of the calculation of weather normalized test period consumption for the residential, commercial, and multi-family housing (R-4) rate classes been filed as part of this rate case?

A. Yes. The details are filed as part of the Minimum Filing Guideline number 34.

Q. Have Base Load and Heat Sensitive Factors for the residential class changed since the last rate case?

A. Yes. Residential Base Load and Heat Sensitive Factors calculated in 1997 were 17.224 and 0.208678 (in Ccfs) respectively. Current Base Load and Heat Sensitive Factors are 12.68 and 0.188213 (in Ccfs) respectively (see EXHIBIT PGB-2 for a comparison of current to proposed WNA factors).

Q. Why have these factors changed?

A. The decline in base use and use per degree day is further evidence of declining use per customer as described earlier in my testimony.

Q. Has the commercial class experienced the same pattern?

A. Yes. Commercial Base Load and Heat Sensitive Factors calculated in 1997 were 221.606 and 0.987685 (in Ccfs) respectively. Current Base Load and Heat Sensitive Factors are 168.979 and 0.797363 (in Ccfs) respectively. Again, the change in base usage and use per degree day is evidence of declining use per customer in the commercial class.

Q. Why is it important to update these factors?

A. Updating these factors will result in a more accurate usage forecast, as well as a more accurate WNA program adjustment on customers' bills.

Q. Was usage during the test period by industrial customers normalized?

A. No. Usage by industrial customers is generally not weather dependant and is not subject to weather normalized billing. Test period usage for industrial customers is actual, not weather normalized.

Section 3

Q. Please describe the results of the forecast for customer growth for the residential class.

A. The Company projects a 1.14% increase in annual residential bills for 2004 and 1.09% increase in annual residential bills for 2005. Please see EXHIBIT PGB-3 for the results of the forecast for 2004 and 2005, and the resulting annual residential bills for the attrition period.

Q. How were these growth rates developed?

A. Several factors, such as recent historical growth rates, the composite annual growth rate, and projected housing starts in Chattanooga were taken into consideration in the forecast.

Recent historical growth of bills year-over-year varied from 1.84% in 2001 to 2.27% in 2002. The most recent data from 2003 indicates a growth rate of 0.86% over 2002.

The composite annual residential growth rate from the last rate case in 1998 to the 12 months ending September 2003 is 1.4%. The composite rate is reflective of average growth over 5 years. This average removes the volatility of year over year comparisons.

In its Economic Outlook Indicators for Chattanooga dated October 2003, Economy.Com forecasts an 11.7% decline in single family housing starts for 2004 and a further 7.4% decline in 2005.

Given the most recent annual growth of 0.86%, the composite annual growth rate of 1.4% and the forecast of decline in housing starts, the Company's forecast of 1.14% and 1.09% for 2004 and 2005 respectively is appropriate.

Q. Were any other adjustments made to the residential class forecast?

A. Yes. Adjustments to the forecast were made for the conversion of 119 units from multi-family housing (R-4) to the residential class. The conversion is reflected as an increase in residential billing units beginning June 2004.

Q. Please describe the results of the forecast for customer growth for the commercial class.

A. The Company projects a 1.0% increase in annual commercial bills for 2004 and 1.0% increase in annual commercial bills for 2005. Please see EXHIBIT PGB-3 for the results of the forecast for 2004 and 2005, and the resulting annual commercial bills for the attrition period.

Q. How were these growth rates developed?

A. As with the residential class, several factors were considered to develop the commercial growth rate, such as recent historical annual growth, composite growth, and economic indicators.

Annual bill growth rates varied from 1.53% in 2001 to 1.97% in 2002, and declined to 0.73% in 2003.

The composite annual growth rate from 1998 to the 12 months ending September 2003 was 0.73%. Again, the composite rate reflects average growth over 5 years, which removes the volatility of year over year growth comparisons.

Economy.Com, as of October 2003, forecasts an increase in the national Consumer Price Index for 2004 and 2005, indicating slow but favorable economic growth.

Taking into consideration the historic growth in the commercial class and the favorable economic outlook, the Company feels that its forecast of 1.0% annual growth is aggressive but appropriate.

Q. Please describe the forecast for customer growth for the Multi-family Housing (R-4) class.

Chattanooga currently has 3 Multi-family Housing (R-4) customers with 265 billing units. Company marketing personnel, through discussion with customers, estimate that 2 customers will leave the R-4 class. One customer will be converted to 119 individually metered units in June 2004. This conversion is reflected as a decrease in R-4 customers and units and an increase to residential customers. The second customer is expected to leave Chattanooga's system completely. The loss of this customer is reflected in the R-4 customer and unit forecast as a steady decline of 80 units beginning January 2005 and ending December 2005. This translates into a change in bills from the test period to the attrition period of (793) winter bills and (961) summer bills, as shown in column 4 of Exhibit PGB-4, for a total annual change of (1,754) bills.

Q. Please describe the forecast for the Industrial customers.

The Company projected Industrial customers for the attrition year by adjusting test year actual customer counts, by month, for known gains and/or losses to reflect the most current levels. Based on analysis and market intelligence, the Company's marketing personnel expect future levels of customers to remain the same.

Section 4

Q. How were distribution volumes forecasted for the attrition period for the residential class?

A. For calendar years 2004 and 2005, the Company estimated billing cycle beginning and ending dates. The total number of normal degree days and the total number of days in each cycle was calculated. The WNA factors used in the test period normalization process were used as factors to determine normal attrition period usage. The Base Load factor was multiplied by the number of days in each billing cycle and by the number of customers forecasted for each cycle to determine total base load for the cycle. The Heat Sensitive factor was multiplied by the number of normal degree days for each cycle and by the number of customers forecasted for each cycle to determine the total heat sensitive use for the cycle. Total base load and total heat sensitive load for each cycle were added together to produce total usage for the cycle. Total usage for each billing cycle was aggregated by relative month to produce monthly usage.

Q. Were commercial and multi-family housing (R-4) class distribution volumes forecasted for the attrition period using the same methodology as residential?

A. Yes. While the analysis was performed on the individual rate classes, the process described above was the same.

Q. Do you support an exhibit that compares test period usage to attrition period usage?

A. Yes. Please see EXHIBIT PGB-4, which details the normalization and growth adjustments made to the test period to project the attrition period.

Q. Please discuss how industrial usage was forecasted for the attrition period.

A. Industrial usage for the test period was separated into the I1/T1, L1/T2, SS-1, and Special Contract classes, consistent with data supplied in monthly reports to the TRA. I1/T1 test period monthly volumes were adjusted for the gains and losses of usage of known customers to date with no other adjustments. L1/T2 test period monthly volumes were adjusted for known gains and losses of customers to date as well as a 4% decline in use per customer over the previous year.

Q. How did the Company determine that a 4 percent decline in use per customer for L1/T2 customers was appropriate?

A. Declines in annual average use per customer, over the previous year, for this class have been 11% in 2001, 4% in 2002, and approximately 10% in 2003. A 4% decline in average use per customer annually is a conservative estimate and is deemed appropriate for this forecast.

Q. How did the Company forecast usage volumes for SS-1 customers?

A. Industrial customers have the option of transferring to the SS-1 rate class on a monthly basis. This behavior is dependant on prevailing market conditions each month and, thus, is difficult to project. Actual test period volumes for SS-1 class were used as the forecast for the attrition period.

Q. How did the Company forecast usage volumes for the Special Contract customer?

Test period Special Contract volumes are not expected to change materially during the attrition period, thus, actual test period volumes were used as the forecast for the attrition period

<u>Section 5</u>

Q. Were the volumes forecasted in Section 4 above used to determine attrition period margin and revenue?

A. Yes. The volumes forecasted above for the attrition year were used to determine attrition period margin and revenue under both current and proposed rates.

Q. Proposed rates are billed on a per therm or dekatherm basis. Were attrition period volumes adjusted to reflect the change?

A. Yes. Current rates are set on a per Ccf or Mcf basis. To calculate proposed rates, the volumes (in Ccfs and Mcfs) forecasted in section 4 were multiplied by a BTU factor of 1.01744 (as calculated in EXHIBIT PGB-5) to convert Ccfs and Mcfs to therms and dekatherms respectively. Proposed rates were then calculated on a per therm or per dekatherm basis.

Q. What other billing determinates were used to forecast attrition period margin and revenue?

A. Customer counts and R-4 unit counts forecasted in Section 3 above were also used to determine attrition period margin and revenue. "Other Operating Revenue" billing determinates such as the number of turn-ons, number of meter sets, etc. were also used and will be discussed later in this testimony.

Q. What procedure was used to project base revenue under current rates for the residential and commercial classes?

A. Residential and commercial forecasted monthly usages were allocated within the blocks of each rate class based on previous volumes usage patterns. Forecasted volume for each block was multiplied by current rates to produce projected volumetric revenues. Forecasted customer counts were multiplied by current customer charge rates to produce customer charge revenues.

Q. How were multi-family housing (R-4) revenues projected using current rates?

A. Forecasted monthly volumes and unit counts were multiplied by current rates to produce forecasted revenues.

Q. Please explain how base revenues under current rates were calculated for industrial rate classes?

A. I1/T2, L1/T1, and SS-1 monthly usages were allocated within the blocks of each rate class based on previous class usage patterns. Forecasted monthly volume for each block was multiplied by current rates to produce projected volumetric revenues. Forecasted customer counts were multiplied by current customer charge rates to produce customer charge revenues. Revenues for Special Contracts were calculated using actual volumes from the test period multiplied by the contracted rates to produce revenue under current rates.

Q. Please list the sources of 'other revenue" not associated with base revenue.

A. Other revenue items include revenue from turn-ons, meter sets, reconnects, seasonal reconnects, returned checks, late payment fees, damage billing, and jobbing.

Q. Please explain procedures used to calculate revenue associated with these charges.

A. Historic levels of turn-ons, meter sets, reconnects and seasonal reconnects, returned checks, and jobbing were examined and test period levels were adjusted for growth and multiplied by current rates to forecast the attrition period revenue. Damage billing revenue was forecasted to reflect normal levels of damage billing collections adjusted to reflect the Company's efforts to reduce system damages. Late payment revenue was calculated as a percentage of total operating revenue for the attrition period. The percentage of total revenue used to calculate late payment revenue is consistent with data from the past 3 years.

Q. How were Purchase Gas Adjustment (PGA) revenues projected?

A. The projected PGA rate for each class was applied to forecasted sales volumes to produce PGA revenue. The actual PGA rates in effect at the end of the test period were used as the projected PGA rates.

Q. What was the result of the attrition period margin and revenue forecast under current rates?

A. Total margin for the attrition period under current rates is projected to be $30,196,467. Total operating revenue for the attrition period under current rates is projected to be $93,418,021. Please see column 3 of EXHIBIT PGB-6 for a summary of attrition period base revenue under current rates.

Section 6

Q. What is the Company's revenue requirement for the attrition period?

A. The Company proposes an attrition period base revenue requirement of $34,757,166.

Q. Are existing rates sufficient to recover the revenue requirement?

A. No. The comparison of projected attrition period base revenue under current rates to the projected attrition period revenue requirement yields a base revenue deficiency of $4,560,699. The details of the deficiency are discussed in the testimony of Mr. Michael Morley.

Q. Has the Company developed rates to recover this $4.56 Million deficiency?

A. Yes. The rates necessary to recover this deficiency are presented on EXHIBIT PGB-6. These rates are in the proposed tariffs filed in this proceeding.

Q. What would the impact of these rates be on each customer class?

A. As shown in EXHIBIT PGB-7, the increase in rates for reconnection and seasonal reconnection charges, and the increase in the calculated amount of late payment revenue, account for $88,949 of the revenue deficiency. The residual amount, $4,471,750, is allocated to the firm and industrial rate classes evenly as an increase of approximately 15.3%.

Q. Are the rates shown on EXHIBIT PGB-6 and EXHIBIT PGB-7 those that the Company proposes to place into effect March 1, 2004?

A. No. In this proceeding, the Company is proposing to capitalize carrying charge on stored gas inventory and implement a bare steel and cast iron pipeline replacement tracker as discussed by Mr. Steve Lindsey. The impact of these two proposals would be to remove approximately $2,104,830 from base rates. The required rates to recover the remaining $2,455,869 of base revenue are presented on EXHIBIT PGB-8. These are the rates the Company would prefer to become effective on March 1, 2004 along with the capitalization of carrying charges on stored gas inventory and the bare steel and cast iron pipeline replacement tracker.

Q. What would the impact of these rates be on each customer class?

A. As shown in EXHIBIT PGB-9, the increase in rates for reconnection and seasonal reconnection charges, and the increase in the calculated amount of late payment revenue, account for $75,941 of the revenue deficiency. The residual amount, $2,379,928, is allocated to the firm and industrial rate classes evenly as an increase of approximately 8.2%.

Please see EXHIBIT PGB-10 for a comparison of current rates, proposed as filed rates, and the Company's preferred rates.

Q. As proposed, are the rates preferred by the Company designed to fairly and appropriately recover the residual amount from the firm and industrial rate classes?

A. Yes. As shown in EXHIBIT PGB-9, proposed rates for the firm and industrial rate classes fully recover the residual amount of the requested rate relief.

Q. Does this complete your testimony?

A. Yes, it does.

BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED DIRECT TESTIMONY
of
RICHARD LONN

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO.

Q. Please state your name, position and address.

A. Richard R. Lonn, Director, Regulatory Compliance, AGL Services Company. My business address is 10 Peachtree Place, Location 1365, Atlanta, Georgia 30309

Q. What are your principal responsibilities as Director, Regulatory Compliance?

A. I am responsible for ensuring that all three operating companies (Atlanta Gas Light Company, Virginia Natural Gas, Inc. and Chattanooga Gas Company) are in compliance with all appropriate Federal and State rules and regulations, which includes pipeline safety, OSHA and environmental regulations. This is accomplished through the establishment of operating, safety and environmental manuals and procedures, internal auditing and working with regulators in all three states which we serve.

Q. Please outline your educational and professional training and experience.

A. Attachment _A_ outlines a summary of my educational and professional experience

Q. Have you previously submitted testimony before the Tennessee Regulatory Authority ("TRA") or any other regulatory commission?

A. Yes, I submitted testimony before the Georgia Pubic Service Commission in summer of 2002 as a part of Docket No. 15527-U related to Lost and Unaccounted For Gas.

Q. What is the subject of your testimony?

A. I will present a description of Chattanooga Gas Company's ("Chattanooga" or the "Company") proposed Bare Steel and Cast Iron Pipeline Replacement Program (PRP) tracker including the proposed cost of service impact during the attrition period and the expected tracker recovery for the first two years of the PRP tracker. I will also present a description of Chattanooga's pipeline integrity program.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring Exhibit No. RRL-1, Schedule 1 which contains the estimated expenditures for the PRP. I am also sponsoring Exhibit No. RRL-1, Schedule 2 which contains various schedules to support Chattanooga's cost of service related to the PRP included in the attrition period and the cost of service related to the first two years of the PRP tracker.

Q. Were these exhibits and related schedules prepared under your direction and supervision?

A. Yes.

Q. Please describe the PRP.

A. The PRP is a 10 year plan that will remove all 100 miles of bare steel and cast iron main and related services from the Chattanooga system. The pipe to be replaced was identified using the Company's graphical information system which identifies all of the various types and sizes of main throughout the system. The pipe will be replaced using primarily plastic pipe and some cathodically protected steel for high pressure main. Chattanooga is proposing that the PRP costs be recovered separate from base rates through a tracker.

Q. Why does Chattanooga need to replace its bare steel and cast iron main?

A. Bare steel pipe is a type of steel main that was installed without an effective protective coating. Due to the lack of protective coating, this type of pipe cannot normally be effectively protected against corrosion. Corrosion of metals is a naturally occurring phenomenon which returns the metal to its native or ore state. The gas industry began extensively using pipe with more effective coatings in the late 1950's. Most steel main installed before this time is considered bare steel, although some pipe installed after this is considered bare steel also. Because bare steel pipe cannot be effectively protected it has the potential to leak more often. Therefore, this type of pipe must be leak-surveyed and monitored more frequently than protected pipelines per Federal Code 192.

Q. Please continue.

A. Cast iron pipe pre-dates the use of steel pipe in the gas industry. Prior to the widespread use of steel pipe, cast iron or ductile iron pipe was used exclusively. This type of pipe has many problems associated with its use. Cast iron pipe cannot be welded, so it is installed in individual pieces with a joint between every two pieces of pipe. Cast iron joints shift and leak, creating costly repairs. Cast iron, over time, begins to graphitize, losing its wall integrity and becoming soft and breakable. This has the potential to cause catastrophic failure in the pipeline whenever there is ground movement such as third party excavations or even ground movement due to frost or drought. As virtually all of this pipe is installed in urban areas, this creates additional safety and restoration concerns. Again, this type of pipe must be leak-surveyed and monitored more frequently than protected pipelines per Federal Code 192. Because neither bare steel nor cast iron pipe can be effectively protected against corrosion using cathodic protection, both will degenerate and result in increasing maintenance costs and safety concerns.

Q. What are the benefits of replacing bare steel and cast iron pipe?

A. The primary benefits are reduced escalation of maintenance costs and increased safety on those particular parts of the system. The replacement will result in not having to repair an ever increasing number of leaks related to bare steel and cast iron pipeline and will remove the chance of catastrophic failure associated with cast iron pipe. In the long-term the escalation of the maintenance costs related to the repair of those leaks and the restoration of pavement will be reduced due to the replacement of that pipe.

Q. Are there any other benefits?

A. Yes. Removal of this older pipe from the system will allow Chattanooga to more efficiently operate its system. The newer pipe will be able to handle increased operating pressures which will help to reduce potential pressure delivery problems during high gas demand periods. Increasing system operating pressures will also allow Chattanooga to install less costly smaller diameter pipe when adding to its distribution system. Chattanooga will be able to use smaller diameter pipe because higher pressure systems will allow the smaller pipe to move the same volume of gas as the costly larger diameter pipe. Finally, Chattanooga will be able improve its operations by discontinuing the use of many of the special fittings needed for the repair of the bare steel and cast iron pipe.

Q. What are the estimated costs of the PRP?

A. The costs of the program are summarized on Exhibit No. RRL-1, Schedule 1. The total estimated capital expenditures required to install the new pipe is included in column 5 of Schedule 1 and totals $32,736,213 over the ten year program. The estimated cost of removing the old bare steel and cast iron pipe is included in column 6 and totals $4,347,526 over the ten year program. The estimated total cost of the program is $37,083,739 over ten years.

Q. How will the cost be recovered from customers?

A. The Company is proposing that the PRP cost of service be recovered through a separate revenue tracker. The PRP tracker would have a duration of ten years consistent with the duration of the PRP. At the end of the ten year tracker the un-recovered investment in the PRP would be included in base rates for recovery. However, recovery through the tracker would continue until base rates are adjusted to include the un-recovered investment in the PRP.

Q. Why do you propose to recover the PRP cost of service through a separate revenue tracker?

A. The PRP costs are significant annual non-revenue producing capital expenditures. These expenditures will increase the net utility plant investment for Chattanooga and result in a significant additional revenue requirement throughout the PRP. The net addition to utility plant annually would be approximately $3 million and would increase rate base by approximately 3%. Without a tracker to recover the cost of service Chattanooga will be required to file for rate relief annually. Filing rate cases annually would be an inefficient approach to the recovery of the PRP cost of service and would increase operating expenses for the Company. Chattanooga's estimated cost of filing a rate case is $300,000 and this cost would be included in each annual request for rate relief. The PRP tracker would allow Chattanooga to recover its cost of service by means most efficient for the Company and the TRA.

Q. Mr. Lonn, please describe the operation of the PRP tracker.

A. The PRP tracker would be designed to recover the PRP cost of service incurred during the pipeline replacement period of ten years. The cost of service would include an operating income recovery component, a return on rate base recovery component and a carrying cost component. The total cost of the PRP would be accumulated for each calendar year for recovery. Calendar years would be defined as the "Cost Year" for the PRP. Chattanooga would recover from customers the PRP cost of service for each Cost Year over annual periods beginning each April 1 following a Cost Year. Each recovery period would be referred to as a "Collection Year." The cost of service would be billed to customers per therm of usage based on total throughput. The amount billed per therm would equal the total cost of service/revenue requirement for the Cost Year divided by the actual therm throughput for that Cost Year. Any amount over or under collected during a Collection Year would be included in the calculation of the amount to be collected in the following Collection Year.

Q. Please describe and quantify the calculation of the PRP cost of service and the resulting revenue requirement for the attrition period.

The three components of the cost of service used to calculate the revenue requirement related to the PRP are an operating income component, a return on rate base component and a carrying cost component. Exhibit No. RRL-1, Schedule 2 summarizes the cost of service of the PRP and shows the estimated cost of service for the attrition period and the first two Cost Years. The operating income component includes depreciation expense related to PRP assets less income tax expense effects. As shown on lines 1 through 3, column 1 of Schedule 2, the PRP decreases operating income by $50,977 for the attrition period. The resulting revenue requirement for the attrition period is $84,220.

The return on rate base component is Chattanooga's cost of capital authorized on its rate base or investment in the PRP program. The rate base related to PRP is calculated as cumulative capital expenditures for PRP assets less a deduction for accumulated depreciation and a deduction for accumulated deferred income taxes. The balance in accumulated depreciation is a debit balance due to the fact that the cost of removal included in the accumulated depreciation balance and exceeds the deprecation related to the PRP assets. As shown on lines 5 through 8, column 1 of Schedule 2, the increase in average rate base resulting from the PRP for the attrition period is $2,237,166. The resulting revenue requirement for the attrition period is $275,118.

The carrying cost component is the cost of capital authorized to compensate for the delay in recovery of the cost of service/revenue requirement PRP revenues during the Collection Year. A delay occurs because revenues earned in a Cost Year are not collected under the PRP tracker until the following Collection year. Carrying costs are not included in the attrition year calculation of revenue requirements impact because the revenue requirement for the attrition period is assumed to be collected during the attrition period; therefore, no carrying charges would be incurred. The total revenue requirement related to the PRP for the attrition period is $359,338 and is shown on line 11, column 1. Columns 2 and 3 show the same revenue requirement elements of the PRP for the first two Cost Years. Note, however, that carrying costs are included in the calculation on line 10 because carrying costs are incurred under the PRP tracker due to a delay in recovery of the revenue requirements. The estimated revenue requirements for the Cost Years ending December 2004 and December 2005 are $181,884 and $612,152 respectively.

Q. Please describe the pipeline integrity initiative.

A. In December of 2002 the President signed into law the Pipeline Safety Act of 2002. This Act requires gas companies to take additional steps in several areas to insure the integrity of their transmission pipelines which are normally the largest and most critical pipeline facilities for an LDC. The Pipeline Integrity Initiative was developed in response to the Act.

Q. What does the Pipeline Safety Act of 2002 require?

A. First, it requires gas operators to increase and enhance their public education efforts as they relate to several different groups including emergency responders, excavators, customers and people who live along and near transmission lines. To comply with the Act, Chattanooga is developing a more comprehensive communication plan than was required under previous regulations. Second, Chattanooga will be required to test the integrity of its 6.5 miles of transmission pipeline to determine whether there are anomalies which require additional action. Federal regulations require Chattanooga to either smart pig these facilities, take them out of service to hydrostatically test them or perform a process called direct assessment where Chattanooga will take various close interval electrical readings on the pipe. Chattanooga may actually perform a combination of those processes.

Once Chattanooga has performed one or more of the previously mentioned assessments and interpreted the data, then it will have to dig up the identified anomalies and determine if there is an integrity problem and if there is, take action to repair the faults.

Q. When do these activities have to be performed and what is the impact on costs?

A. The assessment of pipeline integrity must begin by June 2004 and be completed within ten years. Chattanooga plans to complete the process within three years. The total cost of the program is estimated to be $433,600. The estimated cost of the program during the attrition period is $261,432. Both the communication program and assessment program are programs that the Company will have to perform going forward into perpetuity on a 7 year cycle unless Federal Regulations change in the future.

Q. Does this conclude your testimony?

A. Yes

Attachment A

Richard R. Lonn
Ten Peachtree Place **Work: (404) 584-3552**
Suite 1000
Atlanta, GA 30309

PROFESSIONAL EXPERIENCE:

Atlanta Gas Light Company (April 1985 to present)

Director, Regulatory Compliance June 2002 to present

Responsible for directing the activities of 27 employees in support of all three AGLC Resources Operating subsidiaries (Atlanta Gas Light Co., Chattanooga Gas Co. & Virginia Natural Gas) 1,900,000 customers. Same responsibilities as previous position with the addition of:

1. Damage Prevention
2. Facilities Locating

Chief Engineer & Director, Regulatory Compliance Sept 2000 to June 2002

Responsible for directing the activities of 14 employees in support of all three AGL Resources Operating subsidiaries (Atlanta Gas Light Co., Chattanooga Gas Co. & Virginia Natural Gas) 1,800,000 Customers:

1. Regulatory Liaison (Ga, Tn, Va)
2. Compliance with Federal Regulations
3. Gas System Operations Procedures
4. Audits
5. Corrosion System
6. Corporate Safety
7. Operations Training Development
8. Environmental Procedures
9. Leak Surveys/ROW Operations

Director, Engineering Compliance Aug 1999 to Sept 2000

Responsible for directing the activities of 54 employees. Same responsibilities as previous position with the following additions:

1. Codes & Standards
2. Research & Development
3. Lab Operations
4. Corporate Safety
5. Operations Training

Manager, Engineering Support Services **Nov 1998 to Aug 1999**

Responsible for directing the activities of 47 employees who provide a variety of Engineering and Operations Services in support of the Company's 39 local Service Centers and 1,450,000 customers. A listing of these services includes:

1. Right-of-Way Acquisition
2. Leak Surveys
3. System Corrosion Control
4. Right-of-Way Maintenance
5. Communications Support
6. Materials Specifications
7. Operations Procedures
8. Capacity Planning
9. LNG Engineering Support
10. State & Federal Regulations

Manager, Metro Region Operations & Engineering **Feb 1994 to Nov 1998**

Responsible for the directing the activities of 75 employees who provided a variety of Engineering and Operations Services in support of 9 Service Centers in the Metro Atlanta area and 950,000 customers. A listing of these services includes:

1. Distribution Engineering
2. Contractor Locating
3. System Replacements
4. 24 hr Central Dispatching
5. Construction Contracts
6. DOT/Marta Relocation Work
7. System Improvements
8. System Corrosion Control
9. Safety & Operations Training
10. New Customer Support

Division Engineer, Atlanta Division **Aug 1988 to Feb 1994**

Technical Liaison for Division Vice President and 9 Service Centers in the Metro Atlanta area in support of 950,000 customers. Reported directly to Vice President and assisted him and the Service Centers on all Operations and Engineering Issues including Contractor Locating.

Staff Engineer, Planning and Design **Dec 1987 to Aug 1988**

Responsible for review of all designs and proposals for Atlanta and Augusta Divisions of the company. Handled system capacity planning for the company at that time, doing computer based system modeling to determine the need for future system enhancements.

Distribution Engineer, Atlanta and Marietta Service Centers Apr 1985 to Dec 1987

Provided distribution engineering services for the above listed Service Centers. Duties included Engineering in the following areas:

1. Meter Set Design
2. System Improvements
3. New Business
4. DOT relocations
5. System Replacements
6. Field Inspections
7. Materials Specifications
8. Equipment evaluation

Additional Information:

Professional Engineer in the State of Georgia (March 1992, PE # 19848)
Chairman of the Board for the Utilities Protection Center of Ga.
Past Chairman of American Gas Association Customer Service & Utilization Committee
Atlanta United Way Loaned Executive of the Year Finalist – 1987
Past Chairman of Pipeliners of Atlanta

Education:

Bachelor of Civil Engineering
Georgia Institute of Technology
Atlanta, Georgia
(December 1984)

Military: United States Naval Reserve (active)

August 1981 to August 1983
Petty Office 2nd Class (frocked) – Honorably Discharged

BEFORE THE

TENNESSEE REGULATORY AUTHORITY

In Re: Petition of Chattanooga Gas Company To)
Place Into Effect a Revised Natural Gas Tariff) Docket No. 04-00000

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON BEHALF OF

CHATTANOOGA GAS COMPANY

DIRECT TESTIMONY OF DR. ROGER A. MORIN

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CHATTANOOGA GAS COMPANY

DIRECT TESTIMONY OF DR. ROGER A. MORIN

INTRODUCTION AND SUMMARY

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

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on “Utility Finance,” "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. My more recent book on regulatory matters, Regulatory Finance is a voluminous treatise on the application of finance to regulated utilities and was released by the same publisher in late 1994. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit No. RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before more than forty (40) regulatory bodies in North America, including the Tennessee Regulatory Authority (“TRA”), the Federal Energy Regulatory Commission (“FERC”), and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama
Alaska
Alberta
Arizona
British Columbia
California
Colorado
Florida
Georgia
Hawaii
Illinois
Indiana
Iowa
Kentucky
Louisiana
Manitoba
Michigan
Minnesota
Mississippi
Montana
Nevada
New Brunswick
New Jersey
New Orleans
New York
Newfoundland
North Carolina
North Dakota
Ohio
Oklahoma
Ontario
Oregon
Pennsylvania
Quebec
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Washington
West Virginia

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the common equity capital invested in the natural gas distribution business of the Chattanooga Gas Company ("CGC" or the "Company"), which is a wholly-owned subsidiary of AGL Resources ("AGL"). Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDIX ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Exhibits RAM-1 through RAM-9 and Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. I recommend the adoption of a rate of return on common equity of 11.25%. My recommendation is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the plain vanilla CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed three risk premium analyses: (1) a historical risk premium analysis on the natural gas distribution industry, (2) a historical risk premium analysis on the electric utility industry as a proxy for the Company's business, and (3) a study of the risk premiums allowed in the natural gas distribution industry. I also performed DCF analyses on two surrogates for the Company's natural gas distribution business. They are: a group of natural gas distribution utilities and a group of investment-grade combination gas and electric utilities.

My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses, and to the Company's current risk environment which I estimate to exceed that of the industry. My recommended rate of return- is also predicated on a capital structure consisting of 49% common equity capital.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three (3) sections:

I. Regulatory Framework and Rate of Return

II. Cost of Equity Estimates

III. Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized, and the Company's risk profile is evaluated.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity: one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES THE COMPANY'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT COMPANY, AGL RESOURCES?

A. I am treating CGC as a separate stand-alone entity, distinct from its parent company AGL because it is the cost of capital for CGC that we are attempting to measure and not the cost of capital for AGL's consolidated overall activities. Financial theory clearly establishes that the true cost of capital depends on the use to which the capital is put, in this case CGC's natural gas distribution operations in the State of Tennessee. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost, but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on CGC is the return foregone in comparable risk natural gas distribution operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility division such as CGC is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. UNDER TRADITIONAL COST OF SERVICE REGULATION PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate CGC's cost of common equity capital.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON COMMON EQUITY?

A. The basic premise is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN ON COMMON EQUITY?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u>, 262 U.S. 679 (1923).
2. <u>Federal Power Commission v. Hope Natural Gas Company</u>, 320 U.S. 391 (1944).

The <u>Bluefield</u> case set the standard against which just and reasonable rates of return are measured:

"*A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public <u>equal</u>*

> *to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties*." (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

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

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."*

Therefore, the "end result" of the TRA's decision should be to allow CGC the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service.

While utilities like CGC enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual interest payments and preferred dividends. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

II. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RATE OF RETURN ON COMMON EQUITY FOR CGC?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to CGC.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

Q. ARE THERE ANY DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF CHANGE?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the energy utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation and the transition to a more competitive environment. As a result, they may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several energy utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. A similar argument applies to historical risk measures. Historical measures of risk, such as beta, are likely to be downward-biased in assessing the present risk circumstances of the industry.

Q. DR. MORIN, ARE YOU AWARE THAT SOME REGULATORY COMMISSIONS AND SOME ANALYSTS HAVE PLACED PRINCIPAL RELIANCE ON DCF-BASED ANALYSES TO DETERMINE THE COST OF EQUITY FOR PUBLIC UTILITIES?

A. Yes, I am.

Q. DO YOU AGREE WITH THIS APPROACH?

A. While I agree that it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All of these methodologies are accepted and used by the financial community and supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. I submit that a regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price or the cost of equity.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF MORE THAN A SINGLE METHOD?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Brigham, a widely respected scholar and finance academician, asserts:

> *In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some*

> *very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.*[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

> *However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods.....*[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

> *The constant growth formula and the capital asset pricing model are two different ways of getting a handle on the same problem.*[3]

In an earlier article, Professor Myers explains:

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.*[4]

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[1] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 256 (4th ed., Dryden Press, Chicago, 1985)
[2] Id. at p. 348.
[3] R. A. Brealey and S. C. Myers, Principles of Corporate Finance, p. 182 (3rd ed., McGCraw Hill, New York, 1988)

Q. DOESN'T THE BROAD USAGE OF THE DCF METHODOLOGY IN PAST REGULATORY PROCEEDINGS INDICATE THAT IT IS SUPERIOR TO OTHER METHODS?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not always present. One of the leading experts on regulation, Dr. C. Phillips discusses the dangers of relying solely on the DCF model:

> *[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'.*[5]

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology which supplants

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[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67 (Autumn 1978).
[5] C. F. Phillips, The Regulation of Public Utilities Theory and Practice, pp. 376-77 (Public Utilities Reports, Inc., 1988). [Footnotes omitted]

other financial theory and market evidence.

Q. DO THE ASSUMPTIONS UNDERLYING THE DCF MODEL REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is dangerously fragile at this time.

Several fundamental and structural changes have transformed the energy utility industry since the standard DCF model and its assumptions were developed. Deregulation, increased competition triggered by national policy, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, and mergers-acquisitions have all influenced stock prices in ways that deviated substantially from the early assumptions of the DCF model. These changes suggest that some of the raw assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, are of questionable pertinence at this point in time for utility stocks, and that the DCF model should be complemented, at a minimum, by alternate methodologies to estimate the cost of common equity.

Q. IS THE CONSTANT RELATIVE MARKET VALUATION ASSUMPTION INHERENT IN THE DCF MODEL ALWAYS REASONABLE?

A. No, not always. Caution must also be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations. The traditional DCF model is not equipped to deal with surges in market-to-book (M/B) and price-earnings (P/E) ratios. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. That is, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings) ratio, and that the stock price will grow at the same rate as the book value. This must be true if the infinite growth assumption is made.

This assumption is somewhat unrealistic under current conditions. The DCF model is not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by several utility stocks, in recent years.

In short, caution and judgment are required in interpreting the results of the DCF model because of (1) the effect of changes in risk and growth on energy utilities, (2) the fragile applicability of the DCF model to utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at a ROE recommendation.

Q. HOW DID YOU APPLY THE RISK PREMIUM METHOD TO CGC?

A. In order to quantify the risk premium for CGC, I have performed five risk premium studies. The first two studies deal with aggregate stock market risk premium evidence and the other three deal directly with the energy utility industry.

A. CAPM ESTIMATES

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, $(R_M - R_F)$. For the risk-free rate, I used 5.3%. In order to estimate the CAPM return for CGC, I used a beta estimate of 0.77 and a market risk premium estimate of 7.0%. These inputs to the CAPM are explained below.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on thirty-year Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHY DID YOU SELECT THE YIELD ON 30-YEAR TREASURY BONDS AS A PROXY FOR THE RISK-FREE RATE IN THE CAPM ANALYSIS?

A. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the risk premium method. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subjected to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

The level of U.S. Treasury 30-year long-term bond yields prevailing in early December 2003 as reported in the Value Line Investment Survey for Windows (“VLISW”) December 2003 edition was 5.3%, which is my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return which cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

Of course, as a wholly-owned subsidiary of AGL, CGC is not publicly traded, and therefore, proxies must be used. Given the Company's relatively small size, it is reasonable to postulate that CGC possesses an investment risk profile that is at least as risky as that of the average risk publicly-traded natural gas distribution utility company. As a conservative proxy for the Company's beta, I have therefore examined the betas of a sample of publicly-traded natural gas distribution utilities contained in the current edition of the Value Line Investment Survey for Windows software ("VLIS"). In order to minimize the well-known thin trading bias in measuring beta, only those companies whose market capitalization exceeded $500 million were considered. The average beta for the group is 0.73 as shown on page 1 of Exhibit RAM-2. As a second proxy for the Company's natural gas distribution business, I examined the beta for investment-grade combination gas and electric utilities covered by Value Line. This group is discussed later in my testimony. The average beta of these companies is 0.77, as displayed on page 2 of Exhibit RAM-2. By way of additional comparison, the average beta for all the electric utilities covered by Value Line is also 0.77, as displayed on page 3 of Exhibit RAM-2. Based on these results and CGC's relatively small size I shall use 0.77 as my beta estimate.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 7.0%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2003 Yearbook*, compiling historical returns from 1926 to 2002, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.4%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.0%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 7.0% as well. Therefore, I have used 7.0% as a reasonable estimate of the market risk premium.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MARKET RISK PREMIUM ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using the current edition of Value Line's VLISW software. The dividend yield on the aggregate market is currently 2.5%, and the projected dividend and earnings growth rate for the several thousand dividend-paying stocks covered by Value Line averages 7.2% and 11.6%, respectively. Adding the two components together produces an expected return on the aggregate equity market in the range of 9.7% to 14.1%, with a midpoint of 11.9%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.1%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 12.3%. The implied risk premium is therefore 7.0% over long-term U.S. Treasury bonds that are currently yielding 5.3%. It is noteworthy that both the prospective and historical estimates are identical.

As a check on my market risk premium estimate, I examined a recent comprehensive article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[6]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year is then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that

[6] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

year. The table below, drawn from HMMO Table 2, displays the average estimate prospective risk premium (Column 2) for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2%, attesting to the conservative nature of my 7.0% estimate.

Market Risk Premium Estimates

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE COST OF EQUITY FOR THE AVERAGE RISK NATURAL GAS DISTRIBUTION UTILITY USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.3%, a beta of 0.77, and a market risk premium of 7.0%, the CAPM estimate of the cost of common equity for the average risk natural gas distribution utility is: 5.3% + 0.77 x 7.0% = 10.7%. This estimate becomes 11.0% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. This literature is conveniently summarized in Chapter 13 of my book, Regulatory Finance, published by Public Utilities Report Inc. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. These expanded CAPMs typically produce a risk-return relationship that is "flatter" than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings.

The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 5.3% for R_F, a market risk premium of 7.0% for $R_M - R_F$ and a beta of 0.77 in the above equation, the return on common equity is 11.1% without flotation costs and 11.4% with flotation costs.

B. HISTORICAL RISK PREMIUM

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION UTILITY INDUSTRY.

A. As a proxy for the risk premium applicable to CGC, an historical risk premium for the natural gas distribution utility industry was estimated with an annual time series analysis from 1955 to 2001 applied to the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable for periods prior to 1955. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

The average risk premium over the period was 5.7% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.3%, the implied cost of equity for the average natural gas utility from this particular method is 5.3% + 5.7% = 11.0% without flotation costs and 11.3% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.

A. It is reasonable to postulate that the Company's natural gas distribution utility business possesses an investment risk profile similar to that of the electricity delivery business. The electric utility business is a reasonable proxy for the natural gas distribution business at this time because it possesses economic characteristics similar to those of natural gas distribution utilities and has enjoyed virtually identical allowed rates of return, attesting to the risk comparability.

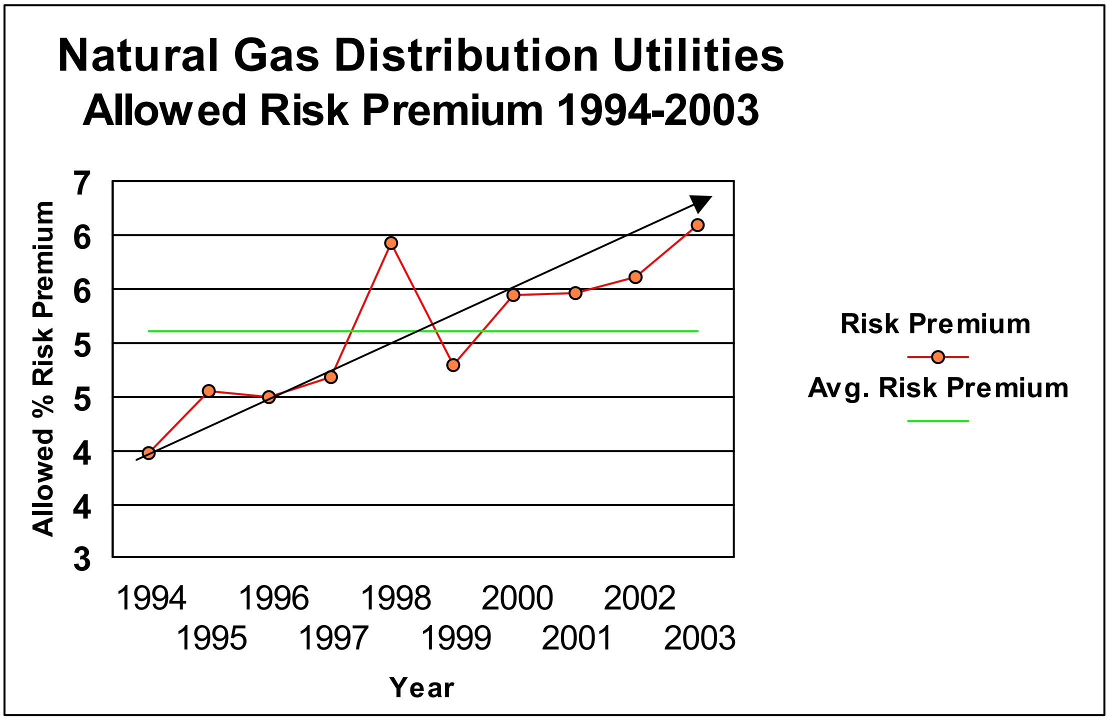
I therefore applied the same historical risk premium analysis to the electric utility industry. An historical risk premium for the electric utility industry was estimated with an annual time series analysis from 1931 to 2001 applied to the electric utility industry as a whole, using Moody's Electric Utility Index as an industry proxy. The analysis is depicted on Exhibit RAM-4. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001 using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

The average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.3%, the implied cost of equity for the average electric utility from this particular method is 5.3% + 5.6% = 10.9% without flotation costs and 11.2% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

C. ALLOWED RISK PREMIUMS

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE NATURAL GAS UTILITY INDUSTRY.

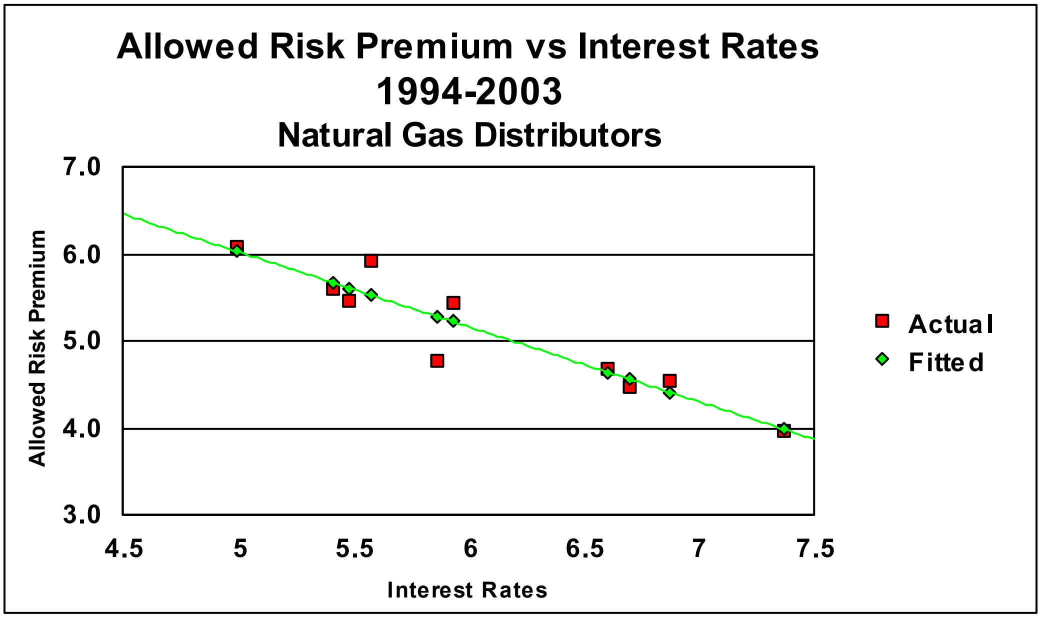
A. To estimate the Company’s cost of common equity, I also examined the historical risk premiums implied in the returns on equity (“ROE”) allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term Treasury yields was 5.1% for the 1994-2003 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. As indicated by the rising arrow on the graph, the escalating trend of the risk premium in response to lower interest rates and rising competition and restructuring is noteworthy.



A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 10.35 - \underset{(t = 7.8)}{0.8626}\ YIELD \qquad R^2 = 0.88$$

The relationship is highly statistically significant as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 5.3% in the above equation suggests that a risk premium estimate of 5.8% should be allowed for the average risk natural gas distribution utility, implying a cost of equity of 11.1% for the average risk utility. Of course, to the extent that CGC is riskier than average, the allowed risk premium applicable to CGC is correspondingly higher.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the various risk premium studies:

Risk Premium	% ROE
CAPM	11.0%
ECAPM	11.4%
Risk Premium Natural Gas	11.3%
Risk Premium Electric Utility	11.2%
Allowed Risk Premium	11.1%

D. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

Where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer

'K_e' from the observed share price, the observed dividend, and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE THE COMPANY'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to two proxies for CGC: a group consisting of widely-traded dividend-paying natural gas distribution companies drawn from the Value Line Gas Distribution Group and a group consisting of investment-grade combination gas and electric utilities. These are the same groups utilized earlier to estimate a proper beta risk measure for CGC.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_o) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the current dividend yields reported in the latest edition of Value Line's VLISW. The vagaries of individual company stock prices are attenuated when using large groups of companies.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO NATURAL GAS DISTRIBUTION UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation because historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE'. That is, $g = b \times ROE$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

I do not generally subscribe to the growth results produced by this particular method for several reasons. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logical trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Finally, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as analysts' growth forecasts[7]. I have therefore placed no reliance on this method.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE NATURAL GAS DISTRIBUTION UTILITY GROUP?

A. The initial group was described earlier in connection with beta estimates, and was displayed on Exhibit RAM-2. The same group was retained for the DCF analysis. However, for purposes of implementing the DCF model, non-dividend paying companies (AmeriGas Partners and Southern Union) were eliminated.

As shown on Column 3 of Exhibit RAM-5, the average long-term growth forecast obtained from the Zacks corporate earnings database is 5.3% for the gas distribution group. Combining this growth rate with the average expected dividend yield of 4.4% shown in Column 4 produces an estimate of equity costs of 9.7% for the gas distribution group. Recognition of

[7] See Vander Weide and Carleton, "Investor Growth Expectations: Analysts vs. History," (The Journal of Portfolio Management, Spring 1988); Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," (Financial Management, Winter 1989).

flotation costs brings the cost of equity estimate to 9.9%, shown in Column 6.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 7.3% instead of the Zacks consensus growth forecast, the cost of equity for the gas distribution group is 11.8%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 12.0%. This analysis is displayed on Exhibit RAM-6.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES?

A. My second group of companies as a proxy for the Company's natural gas business consists of investment-grade combination gas and electric utilities covered in the C. A. Turner Utility Reports, December 2003. Companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Five companies (Duke Power, Alliant Energy, PNM Resources, TECO and TXU) with negative long-term growth projections were eliminated from the DCF analysis. Given the Company's relatively small size, it is reasonable to postulate that the Company's natural gas distribution business possesses an investment risk profile that is at least as risky as investment-grade combination gas and electric utilities. The latter possess economic characteristics similar to those of natural gas distribution utilities, notwithstanding their larger size. They are both involved in the distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital-intensive network with similar physical characteristics. They are both subject to rate of return regulation. The final sample is shown on Page 1 of Exhibit RAM-7.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES GROUP USING THE VALUE LINE GROWTH PROJECTIONS?

A. As shown on Column 2 of page 1 of Exhibit RAM-7, the average long-term growth forecast obtained from Value Line is 5.5% for this group. Adding this growth rate to the average expected dividend yield of 4.3% shown in Column 3 produces an estimate of equity costs of 9.8% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.0%, shown in Column 5. If the two companies whose ROE estimate is less than these companies' cost of long-term debt of approximately 6% (as indicated in the last column of Page 1 of Exhibit RAM-7) are eliminated from the computation, the average ROE estimate for the remaining companies is 10.3%, as shown on Page 2 of Exhibit RAM-7.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES GROUP USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?

A. Using the consensus analysts earnings growth forecast published by Zacks of 5.4% instead of the Value Line forecast, the cost of equity for the group is 8.6%. Allowance for flotation costs brings the cost of equity estimate to 8.8%. This analysis is displayed on page 1 of Exhibit RAM-8. If the three companies whose ROE estimate is less than these companies' cost of long-term debt of approximately 6% (as indicated in the last column of Page 1 of Exhibit RAM-8) are eliminated from the computation, the average ROE estimate for the remaining companies is 9.3%, as shown on Page 2 of Exhibit RAM-8.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for CGC:

DCF STUDY	ROE
Combination Gas & Electrics Zacks Growth	9.3%
Combination Gas & Electrics Value Line Growth	10.3%
Natural Gas Distribution Zacks Growth	9.9%
Natural Gas Distribution Value Line Growth	12.0%

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred; they are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC and the TRA. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, *etc*.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets

$95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE CGC THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, in this case, AGL. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

III. SUMMARY & RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed five risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other three risk premium analyses were performed on aggregate historical and allowed risk premium data from the natural gas distribution and electric utility industry. I also performed DCF analyses on two surrogates for CGC's gas business: a group consisting of investment-grade dividend-paying natural gas distribution utilities and a group of investment-grade combination gas and electric utilities. The results are summarized in the table below.

STUDY	ROE
CAPM	11.0%
ECAPM	11.4%
Historical Risk Premium Electric	11.3%
Historical Risk Premium Natural Gas	11.2%
Allowed Risk Premium Electric Utilities	11.1%
DCF Natural Gas Analysts' Growth	9.9%
DCF Natural Gas Value Line Growth	12.0%
DCF Combination Gas & Electrics Zacks Growth	9.3%
DCF Combination Gas & Electric Value Line Growth	10.3%

The central tendency of the various results is clearly 11%, as indicated by the mean of 10.8%, the median result of 11.1% and truncated mean of 10.9%.

Q. DID YOU ADJUST THESE RESULTS TO ACCOUNT FOR THE FACT THAT CGC IS RISKIER THAN THE AVERAGE NATURAL GAS DISTRIBUTION UTILITY?

A. Yes, I have. The cost of equity estimates derived from the various comparable groups reflect the risk of the average natural gas distribution utility. To the extent that these estimates are drawn from a group of less risky and larger companies, the expected equity return applicable to the riskier and smaller CGC is downward-biased. CGS's investment risks are discussed below. I conservatively estimate the bias to be on the order of 25 basis points. I have therefore increased my ROE estimate of 11.00% for the average risk natural gas distribution utility to 11.25% in order to account for CGC's higher relative risks and smaller size.

Q. PLEASE DESCRIBE HOW YOU ASSESSED CHATTANOOGA GAS COMPANY'S CURRENT RISK ENVIRONMENT.

A. It is convenient to disaggregate a company's risk into two broad components: business risk and financial risk.

TOTAL RISK = BUSINESS RISK + FINANCIAL RISK

Business risk refers to the relative variability of operating profits induced by the external forces of demand for and supply of the firm's products (demand and supply risk), by the presence of fixed costs (operating leverage), by the extent of diversification or lack thereof of services, and by the character of regulation (regulatory risk):

BUSINESS RISK = DEMAND RISK + SUPPLY RISK + REGULATORY RISK

A further distinction is frequently made between short-term and long-term business risks. Financial risk refers to the additional variability of earnings induced by the employment of fixed cost financing, that is, debt and preferred stock capital.

Relative to other local gas distribution companies ("LDCs"), CGC possesses above average demand risk, average supply risk, above average financial risks principally because of its small size, and average regulatory risks. The net result, in my judgment, is that CGC's overall risk slightly exceeds that of other LDCs.

Q. PLEASE DESCRIBE THE BUSINESS RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY IN RECENT YEARS.

A. Yes. The traditional role of LDCs, as intermediaries between pipelines and end-customers has changed drastically in the past several years. Because of policy initiatives enacted by regulators at both the federal and state levels, the business risk environment has changed significantly and the level of risk has increased. Competition in the natural gas industry has increased from both the input and output ends of the intermediation process.

On the one hand, customers have alternative means of filling their energy needs (demand risk). On the other hand, supplies of gas have become riskier due to price and regulatory uncertainty and the gradual removal of barriers to competition by federal policy (supply risk). The LDC is caught in the middle. It has become more difficult to forecast demand, market behavior, financing requirements, earnings, and cash flows.

Q. PLEASE EXPLAIN WHY THE DEMAND RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the output end, competition prevails from alternative energy sources in the gas companies' important markets, especially in the industrial market. Given this increasingly competitive environment, the existing fuel alternatives, and a fragile rate structure, there is a potential incentive for these large volume customers to leave the gas distributor's network and seek alternative energy sources. When these large volume industrial customers represent an important proportion of total revenues, and/or the interruptible demand component from these industrial customers is large, the loss of any or all of these customers has serious financial consequences for gas distributors. Competition from fossil fuel remains high, and oil prices continue to be volatile.

Investors are uncertain as to the final impact of competitive forces which have penetrated the industry and as to the final regulatory reaction to these developments. Uncertainty regarding the impact of more competition in traditionally monopolistic markets increases long-term business risks of the regulated firm in these markets.

Investors and bond rating agencies are aware that the LDC industry is riskier and more vulnerable, especially for those LDCs with a high dependence on a high-volume industrial customer base. For the shorter-term, the LDC industry's vulnerability is enhanced by the current economic slowdown, and by the uncertain timing and magnitude of economic recovery.

Q. ARE THE DEMAND RISKS FACED BY CGC SIMILAR TO THOSE OF OTHER GAS DISTRIBUTION UTILITIES?

A. No, I believe they are higher. While it is true that unlike several LDCs in the industry, CGC does not have overlapping service territories with other LDCs and faces limited competition in the industrial market, the Company faces competition from electricity, oil, coal, and propane in its predominantly residential and commercial market.

The competition is especially severe from electricity for two reasons. First, in the region of Tennessee where the Company operates, electricity prices are highly competitive. Second, the heat load in the residential market areas it service is materially less than that for most gas distribution utilities in the country. These factors, combined with sustained high gas prices and aging appliances ripe for replacement, render electricity a viable alternative. In fact, the usage per residential customer has declined and continues to decline.. In a nutshell, the demand for increased gas volumes is virtually non-existent, and as a result the Company's demand risks exceed those of the industry.

Q. PLEASE EXPLAIN WHY THE SUPPLY RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the input end, the traditional buy-and-sell historical relationship between the regulated LDC and the pipeline supplier has ended, and a dramatic fundamental restructuring of this historical relationship has occurred.

Prior to 1975, long-term gas purchase contracts contained largely fixed prices with specific escalator indices set for the entire term of the contracts. From 1975 to 1986, government involvement in the natural gas industry led to government administered prices. Prior to 1986, uniform pricing did not permit differentiation of delivery conditions in gas purchase contracts. LDCs therefore had little price or contracting risk nor were they required to make choices as to the composition of gas supply portfolios.

Since deregulation, natural gas prices and delivery conditions are subject to market forces, and LDCs are now responsible for making decisions regarding prices, contract differentiation, and supply portfolio composition. The provision of gas supplies to its customers is therefore subject to greater risk of approval of these activities by the regulators. This risk is currently acute for two reasons. First, the continued evolving roles of LDCs in providing gas supplies to various customer groups who have several supply alternatives in a deregulated market complicate the decision process. Whether a LDC intends to be a competitive supplier or is required by regulation to be a supplier of last resort implies a very different set of prices, contract provisions, and portfolio choices.

Second, the rules of the game remain uncertain. This creates the risk that the decisions made by the LDC may not be acceptable to the regulators in hindsight.

Moreover, deregulation brings with it the ability for producers and other natural gas marketers to sell within the service area of CGC and other LDCs creating great uncertainty as to the size of market to be supplied. This risk and the reliance upon other parties for the security of supply and supply planning create a radically different supply risk for LDCs under deregulation.

Broad policy initiatives mandated by the FERC, which addressed open access and take-or-pay (TOP) resolution and were instituted under Order Nos. 436 and 500, and the comparability of service in Orders 636 and 637, have increased and will continue to increase the level of risk associated with CGC's gas supply acquisition function. CGC used to experience this increased risk indirectly but now contends with this risk directly as a result of the divestiture of pipeline supplier's merchant function and the permanent assignment of upstream capacity, which expands CGC's options for obtaining upstream capacity and supply and enables the Company to become a direct customer of other pipelines.

All aspects of the Company's business risks have been affected radically as a result of these various policy initiatives, and will continue to be affected. Supply-related risks have been particularly enhanced. The risks of gas procurement and reliable supply, transportation from production areas to the market, contract negotiations, accounting, and FERC-imposed surcharges have shifted from the merchant pipeline or others to the LDC. As a result, new competitive risks have appeared. For example, LDCs' customers have the opportunity to connect directly to the pipeline and convert their requirements to transportation service. The same business conditions that have the potential to cause this bypass risk can also cause end-customers to shift to alternative fuels when the price of gas is driven upward. In essence, the producers and the pipeline affiliates see the LDC's historical customers as fair game and are aggressively pursuing gas sales or transportation agreements with large commercial customers and major industrial facilities. In a nutshell, the risks of gas supply, transportation from production areas, and contract uncertainties previously assumed by the pipeline have become significant risks for the LDC such as CGC.

This fundamental restructuring reached its climax with the implementation of FERC Order 636, which fundamentally altered the natural gas industry by mandating total unbundling of transmission from sales, shifting risk to the LDC segment of the gas business.

In my judgment, CGC's supply risks are comparable to those of other gas distribution utilities, while its demand risks are higher, as discussed earlier. The net result is that the Company’s business risks are higher than those of the industry.

Q. PLEASE COMMENT ON THE REGULATORY AND FINANCIAL RISKS FACED BY CGC AT THIS TIME.

A. Regulatory risks have remained unchanged, and are similar to those of the industry. Take-or-pay (“TOP”) exposure is absent. The TRA has allowed full pass-through of TOP. With regard to bypass, the TRA has approved special tariffs for large industrial customers with alternative competitive energy sources. Allowed returns have generally proved to be fair and reasonable.

Because of its relatively small size, in my judgment, CGC’s financial risks are higher than those of the industry. CGC possesses small revenue and asset bases, both in absolute terms and relative to other utilities. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is in excess of 5% over the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

In conclusion, in my judgment, CGC's total investment risk is higher than the industry at this time. I have therefore increased my recommended return by 25 basis points, that is, from 11.00% to 11.25% in order to recognize CGC's higher relative risk. The 25 basis points adjustment is based on utility bond yield spreads differentials between A-rated and Baa-rated bonds and on observed beta differentials.

The CAPM formula was also referenced to approximate the return (cost of equity) differences implied by the differences in the betas between the average natural gas utility company and CGC. The basic form of the CAPM, as discussed earlier in my testimony, states that the return differential is given by the differential in beta times the market risk premium, (R_M - R_F). Because I consider CGC's beta to be approximately 0.77, that is to be 0.03 higher than the natural gas industry utility average of 0.73, the return differential implied by the difference of 0.04 in beta is given by 0.04 times (R_M - R_F). Using an estimate of 7.0% for (R_M - R_F), the return adjustment is at least 25 basis points.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING CGC'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of CGC, it is my opinion that a just and reasonable return on the common equity capital of CGC's natural gas distribution operations in the state of Tennessee at this time is 11.25%.

Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON CGC'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for CGC is predicated on the adoption of the Company's test year capital structure consisting of 49% common equity capital and 51% debt capital.

Q. DID YOU EXAMINE THE REASONABLENESS OF THE COMPANY'S TEST YEAR CAPITAL STRUCTURE?

A. Yes, I did. I have compared CGC's test year capital structure with investor-owned natural gas LDCs' capital structures adopted by regulators. The September 2003 edition of Regulatory Research Associates' "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 49% for 2003, the same as the Company's test year capital structure. I have also examined the actual capital structures of comparable risk investor-owned natural gas LDCs. As shown on Exhibit RAM-9, the median common equity ratio of comparable risk natural gas LDCs, the same group of companies used earlier in my testimony when applying the DCF model and estimating beta coefficients, is also 49%.

Finally, I have compared the Company's test year debt ratio of 51% to the capital structure benchmark contained in Standard & Poor's Rating Criteria for electric and gas utilities. The debt ratio benchmark for a single "A" bond rating is 43.0% – 49.5% for a utility with a Business Risk Position of 4.0, the same as Atlanta Gas Light, CGC's sister operating natural gas utility. Of course, CGC has no bond rating assigned by bond rating agencies in view of its small size. The 51% test year debt ratio lies slightly outside the benchmark for a single strong "A" bond rating, which I consider optimal from both ratepayers' and utilities with the same business investors' viewpoints.

If the TRA imputes a capital structure consisting of substantially more (less) debt than the test year capital structure, the higher (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the TRA ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

Q. DR. MORIN, DO YOU CONSIDER IT SOUND PUBLIC POLICY TO PROVIDE A RATE OF RETURN INCENTIVE TO ENERGY UTILITIES?

A. Yes, I do. One serious potential limitation of traditional rate of return/rate base regulation is that an efficient utility company that has achieved superior performance and has managed to mitigate risk and manage its business for the benefit of its customers is awarded a lower ROE than an inefficient utility company that has experienced poor performance, mismanaged risk, and not benefited its customers, and yet that utility is granted a higher ROE. I do not believe such a policy is in the interest of ratepayers, to the contrary.

To the extent that the principal objective of regulation is to act as a substitute for the market place and emulate the returns for industries in the competitive market, the provision of incentive returns is a socially desirable goal of regulation. I consider it sound public policy to provide utilities with a rate of return incentive to reduce costs, achieve productivity gains, and provide more reliable service, and to reward those utilities that have achieved such goals. The reverse is true, of course. Such a return increment provides an incentive for efficiency by allowing the company to keep some excess return. With such a return incentive, management has the opportunity to earn a fair rate of return and, more importantly, has far more incentive to perform efficiently, because the company has more to gain in the form of higher returns. Benefits accrue to investors and ratepayers, the former in the form of enhanced profitability, and the latter in the form of reduced costs. Lower costs and/or higher quality service than otherwise would be the case accrue to ratepayers because a higher return can only be achieved by cost reductions and efficiency gains that in turn reduce the going-in costs of service in subsequent rate cases.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.