# Large Filing Separator Sheet

Case Number : 08-72-GA-AIR
08-73-GA-ALT
08-74-GA-AAM
08-75-GA-AAM

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A. Schedule C-8 sets forth, for comparative purposes, projected expenses for this case and Columbia's most recent rate cases. This schedule further provides for the identification of these expenses by type of expenditure which includes the following:

Rate of Return Exhibits and Testimony
Preparation of Rate Case Data
Publish Legal Notices
Class Allocation Exhibits & Testimony
Depreciation Study
Infrastructure Consultant
Miscellaneous Expense
Legal Expense

**Q. Why is the projected expense for this case higher than the most recent two cases?**

A. The estimated increase in rate case expense results from the need to provide support for the numerous changes proposed by Columbia in this case, which includes several proposed changes in rate design; establishment of an Infrastructure Replacement Program designed to address various safety issues; the replacement of an aging distribution system and installation of automatic meter reading devices on all meters located inside customer premises. In addition, this filing further includes a request for the establishment of Rider DSM that will provide for the development of a demand side management program to be made available to customers. These proposed changes resulted in the need to obtain experts to provide expert testimony and studies, which can be used by the Commission to evaluate these proposals. These additional experts will address the rate design and need for the systematic replacement of Columbia's aging distribution system. Finally, due to complexity of this case, Columbia will also use, to a limited degree, outside counsel.

**Q. Why did Columbia use a three year period for the amortization of rate case expense?**

A. The use of a three-year period for recovery of these expenses was selected due to the fact that its impact is less than nine-tenths of one cent per Mcf on customers and results in the annual recovery of rate case expenses comparable to that approved by the Commission in Columbia's most recent cases.

**Q. Please describe Schedule C-9.**

A. Schedule C-9 details, by type of expenditure, all test year and adjusted test year labor, benefits and labor related taxes. The adjustments shown on Schedule C-9 for determination of adjusted test year expenses were taken directly from Schedules C-3.8, C-3.9, C-3.10 and C-3.18.

**Q. Please describe Schedule C-9.1.**

A. Schedule C-9.1 shows for the most recent five calendar years and test year, man hours, labor dollars, employee benefits, payroll taxes and employee levels. In addition Schedule C-9.1 shows, for those same time periods, operation and maintenance expense labor dollars and ratio of expensed labor dollars to total labor dollars; employee benefits expensed and ratio of employee benefits expensed to total employee benefits costs; and payroll taxes expensed and ratio of payroll taxes expensed to total payroll taxes. The test year ratios shown on Schedule C-9.1 were the ratios used by Mrs. Noel in the development of the adjustments shown on Schedules C-3.8, C-3.9, C-3.10 and C-3.18.

**Q. Please describe Schedule C-10.**

A. Schedule C-10 sets forth the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to compute the revenue deficiency. This factor was computed based on an effective gross receipts tax rate of 4.7448% (in recognition of the fact that exempt sales will not be subject to payment of the gross receipts tax) and a federal income tax rate of 35%. No further adjustments are required since these are the only items currently impacted by the change in base rates.

**Q. Please describe Schedule C-11.1.**

A. Schedule C-11.1 shows comparative balance sheets for the five most recent calendar years and date certain. The source of the information shown on these schedules was Columbia's annual reports and books.

**Q. Please describe Schedule C-11.2.**

A. Schedule C-11.2 shows comparative income statements for the most recent five calendar years and test year. The source of the information shown on these schedules was Columbia's annual reports, books and financial plan. The amounts shown for test year Net Operating Income correspond to those amounts set forth on Schedule C-2.1.

**Q. Please describe Schedules C-12.1.**

A. Schedule C-12.1, Page 1 of 2, shows, by revenue class for the most recent five calendar years and test year, sales revenue, transportation revenue, average number of customers, customers served at end of year, average revenue per customer sales and average revenue per customer transportation. Schedule C-12.1, Page 2 of 2, shows, by revenue class for the next five calendar years, projected sales revenue, projected transportation revenue, projected average number of customers, projected number of customers served at end of year, projected average revenue per customer sales and projected average revenue per transportation customer. The source of this data was Columbia's records and financial plan.

**Q. Please describe Schedule C-12.2.**

A. Schedule C-12.2 would normally show the information shown on Schedule C-12.1 for the jurisdiction. This schedule was not completed by Columbia since all of Columbia's sales and transportation revenue are jurisdictional.

**Q. Please describe Schedules C-12.3.**

A. Schedule C-12.3, Page 1 of 2, shows, by revenue class for the most recent five calendar years and test year, sales volumes, transportation volumes, average number of customers, customers served at end of year, average volumes delivered to a sales customer and average volumes delivered to a transportation customer. Schedule C-12.3, Page 2 of 2, shows, by revenue class for the next five calendar years, projected sales volumes, projected transportation volumes, projected average number of customers, projected number of customers served at end of year, projected average volumes delivered a sales customer and projected average volumes delivered per transportation customer. The source of this data was Columbia's financial plan.

**Q. Please describe Schedule C-12.4.**

A. Schedule C-12.4 would normally show the information shown on Schedule C-12.1 for the Jurisdiction. This schedule was not completed by Columbia since all of Columbia's sales and transportation volumes delivered are jurisdictional.

**Q. Please describe Schedule C-13.**

A. Schedule C-13 is An Analysis of Reserve for Uncollectible Accounts for the most recent three years. The ratios shown on this schedule were not used by Columbia in its computation of the revenue requirement in case.

**Q. Why the information on Schedule C-13 not used by Columbia in this case?**

A. These ratios were not used due to the fact that bad-debt expense reflected on Columbia's books is now determined based on recoveries made through the Uncollectible Expense Tracker.

**RATES AND TARIFFS**

**Q. Please explain the proposed tariff change with respect to the applicability of Columbia's Gross Receipts Tax Rider.**

A. Columbia's current tariff limits the applicability of its Gross Receipts Tax Rider to "all gas cost recovery charges billed by Columbia under rate schedules SGS, GS and LGS, except that this rider shall not be billed to those customers statutorily exempted from payment of gross receipts taxes." This rider was applied this way due to the inclusion in base rates of a gross receipts tax level on the balance of the revenue requirement at time base rates were established in Columbia's Case No. 94-987-GA-AIR. Columbia's proposed tariffs provide for the applicability of this tax to all customers, with the exception of gas costs billed on behalf of Retail Natural Gas Suppliers and certain customers exempt from payment of gross receipts taxes, through the removal of all gross receipts taxes from the base rates and the computation of the gross receipts tax on revenues as the last step in the computation of the bill. This change ensures taxes are collected on a dollar per dollar basis with no potential for over or under recovery.

**Q. Please describe Schedule E-4.**

A. Schedule E-4 is multiple page summary of revenue at current and proposed rates by rate schedule and revenue class. The source of information for these schedules is Schedule E-4.1 with the exception of flexed revenue amounts the source of which is Columbia's WPE-4.1a through WPE-4.1d. work papers and "Other Revenue" which comes directly from Columbia's financial plan.

**Q. Please describe Schedule E-4.1.**

A. Schedule E-4.1 shows the derivation of annualized revenue at current and proposed rates for revenue class served under that rate schedule.

**Q. Please describe the format used by Columbia for development of Schedule E-4.1.**

A. Schedule E-4.1 is comprised of 64 pages with revenue at current rates being derived on all odd pages and revenue at proposed rates shown on the even numbered pages. Those pages which show revenue at current rates show the applicable rate schedule; number of bills; throughput at the various break points; most current rates; revenue at most current rates; percent of revenue to total revenue excluding gas costs; revenue increase requested; percent of revenue increase less gas costs; gas costs revenue where applicable; total revenue at current rates; and total revenue percent of increase. Those pages which show revenue at proposed rates show the applicable rate schedule; number of bills; throughput at the various break points; proposed rates; revenue at proposed rates; percent of revenue to total revenue excluding gas cost revenue; gas costs revenue where applicable; and total revenue at proposed rates.

**Q. Why did Columbia use the number of bills rather than the number of customers for computation of revenue at current and proposed rates?**

A. The use of test year customer numbers would have resulted in an understatement of the revenue generated at current and proposed rates shown on Schedule E-4.1 since customers must pay the customer charge regardless of days of service. This treatment can result in the collection of more than one customer charge for a premise during the billing cycle and the understatement of annualized revenue if not recognized. The use of bills produces a revenue level representative of current and future billings under Columbia's current and proposed tariff.

**Q. Does Schedule E-4.1 reflect the use of test year normalized test year throughput?**

A. Yes. However, the normalized test year throughput reflects the use of throughput determined on a twenty-year basis. These throughput estimates were provided by Mr. Gresham who has filed testimony in support of their use in this proceeding.

**Q. Please explain the process used to forecast volumes by rate schedule.**

. This process starts with the volumes provided by Mr. Gresham. Mr. Gresham provides projected throughput by type of service and revenue class. The various types of service are: (1) sales service; (2) traditional transportation service; and, (3) full requirements transportation service. The various classes are residential, commercial and industrial. Forecasted residential volumes, both sales and full requirements, are allocated, by months to rate schedules, based on most recent twelve months history and the rate schedule the customers are on at time of the forecast.

**Q. How is the forecast for commercial volumes by rate schedule prepared?**

A. This process again starts with Mr. Gresham's forecast, and the large volume forecast for certain large sales and large traditional transportation customers. Projected throughput for small volume customers is determined through the subtraction of the large volume forecast for Mr. Gresham's forecast and spread proportionally between Gas Measurement Billing ("GMB") and Distributive Information System ("DIS") based on actual physical flow. DIS bills those sales and transportation customers that do not have any unique billing requirements. The GMB system is used to bill both sales and full requirements transportation customers that have special meter reading equipment or needs under the tariff. DIS volumes are then spread proportionally by rate schedule based on the most recent twelve months of physical flow and the rate schedule the customer is on at the time of the forecast. GMB volumes are spread proportionally by customer based on the most recent twelve months of physical flow and which rate schedule the customer is on at the time of the forecast.

**Q. Were industrial volumes forecasted in the same manner as commercial?**

A. Yes with the exception that DIS volumes are determined on a customer by customer basis.

**Q. How were the various billing blocks shown on these schedules determined for customers billed through Columbia's DIS System?**

A. A bill frequency is created for each rate schedule at the usage levels that coincide with the rate blocks of each rate schedule. The Ogive method is used to create the bill frequencies. Ogive is a statistical term for a distribution curve in which the frequencies are cumulative. This method has been used by Columbia since the 1950s and continues to be highly accurate to within .5% of actual billings.

**Q. How were the consumption levels used for the determination of annualized revenues at current and proposed rates for customers billed through the GMB and GTS billing systems determined?**

A Consumption levels, by rate schedule, are determined through the aggregation of individual customer information on a month-by-month, customer-by-customer basis, ensuring accuracy. This is possible because of the relatively small number of customers billed in these systems.

**Q How was the revenue from the various trackers shown on E-4.1 determined?**

A. The revenue generated from these trackers was based on applicability of the tracker under Columbia's current and proposed tariff. For example under Columbia's current tariff the gross receipts tax rider is only applicable in the case of a sales customer and then only applied to the gas cost component of the bill whereas under the proposed tariff the gross receipts tracker is applicable to all charges. All tracker generated revenue was computed in this manner.

**Q. Please describe Schedule E-5.**

A. Schedule E-5 is a typical bill comparison at various consumption levels that shows current bill and proposed bill at each consumption level; dollar increase; percent of increase and total bill including gas cost where applicable.

**PROJECTED FINANCIAL DATA**

**Q. Please describe Schedule F-1.**

A. Schedule F-1 is a projected income statement, at current rates, for the twelve month period beginning nine months from the date Columbia filed its Application. Because Columbia's Application was filed on March 3, 2008, Schedule F-1 is for the period December 1, 2008 through November 30, 2009. The source of the data used for preparation of Schedule F-1 is Columbia's 5-Year financial plan.

**Q. What is Schedule F-1A?**

A. Schedule F-1A is a projected income statement, for the twelve month period beginning nine months from the date Columbia filed its Application. Because Columbia's Application was filed on March 3, 2008, Schedule F-1A is for the period December 1, 2008 through November 30, 2009. The source of the data used for preparation of Schedule F-1A is Columbia's 5-Year financial plan has been adjusted to provide for the additional revenue that will be produced if the Commission approves the full $87.8 million increase.

**Q. Please describe Schedule F-2.**

A. Section F-2 is Columbia's projected rate base for the twelve month period beginning nine months from the date Columbia filed its application. As previously noted the twelve month period would be December 1, 2008 through November 30, 2009. Rate Base is typically set at the mid-point of the collection year. In this case, the mid-point for the collection year would be May 31, 2009. The source of data used for the development of the rate base is Columbia's 5-Year financial plan with the change in net plant and service being the difference between the forecasted May 31, 2009 levels and the actual December 31, 2007 balance used to prepare the case. Schedule F-2 further assumes there is no change in the working capital requirement from that shown in the rate case and an increase in non-investor sources of funds equal to the change in deferred taxes during the December 31, 2007 through May 31, 2009.

**Q. What is Schedule F-2A?**

A. Schedule F-2A is Columbia's projected rate base for the twelve month period beginning nine months from the date Columbia filed its Application, assuming the Commission approves all of the $87.8 million dollar increase requested in the rate case Application. Schedule F-2A is identical to Schedule F-2 because Columbia does believe the receipt of the full increase requested will have a significant impact on its rate base at that point.

**Q. Please describe Schedule F-2.1 and Schedule F-2.1A.**

**A.** Schedule F-2.1 and F-2.1A show the projected plant in service at the date certain These schedules were combined since Columbia does not believe the receipt of the full increase in rates requested will have a significant impact on it rate base at that point.

**Q. Please describe Schedule F-3.**

A. Schedule F-3 is Columbia Gas of Ohio Inc.'s projected capital structure at the date certain assuming no increase in base rates is authorized. The source of this information was Columbia's 5-Year financial plan.

**Q. Please describe Schedule F-3A.**

A. Schedule F-3A is Columbia Gas of Ohio Inc.'s projected capital structure at the date certain assuming 100% of the $87.8 million requested increase in base rates is authorized. The source of this information used to prepare this schedule was Columbia's 5-Year financial plan adjusted for the impact of the receipt of the full increase requested.

**Q. Please describe Schedule F-4.**

A. Schedule F-4 is Columbia's projected statement of changes in financial position for the twelve month period beginning nine months from the date Columbia filed its Application assuming no increase in rates. As previously noted, the twelve month period would be December 1, 2008 through November 30, 2009. The source of the information used to prepare this schedule was Columbia's 5-Year financial plan.

**Q. What is Schedule F-4A?**

A. Schedule F-4A is Columbia's projected statement of changes in financial position for the twelve month period beginning nine months from the date Columbia filed its Application assuming 100% of $87.8 million requested increase in rates is authorized. As previously noted, the twelve month period would be December 1, 2008 through November 30, 2009. The source of the information used to prepare this schedule was Columbia's 5-Year financial plan adjusted for impact of the increase in revenue and an offsetting impact in short-term debt.

**ALTERNATIVE REGULATION PLAN**

**Q. Please describe the elements that comprise Columbia's alternative regulation plan.**

A. This alternative regulation plan consists of two separate rate recovery mechanisms. The first rate recovery mechanism will provide Columbia with the ability to track and recover, on an annual basis, the costs of implementing an Infrastructure Replacement Program ("IRP"), and will be referred to as Rider IRP. The second rate recovery mechanism will provide Columbia with the ability to recover the costs of implementing a Demand Side Management ("DSM") program, and will be referred to as Rider DSM.

**Q. Please describe Rider IRP.**

A Rider IRP consists of three components. The first component will recover the costs associated with the replacement of natural gas risers that are prone to failure, along with the costs associated with the future installation, maintenance, repair and replacement of customer service lines that have been determined by Columbia to present an existing or probable hazard to persons and property. This is addressed by Columbia witness Roy.

The second component will recover the costs associated with Columbia's Accelerated Mains Replacement Program ("AMRP"). Columbia witnesses Roy and Vitale discuss the AMRP.

The third component will recover the costs associated with Columbia's installation of Automatic Meter Reading Devices ("AMRD"). Columbia witness Bohrer discusses the AMRD.

Under the three components of Rider IRP, Columbia proposes to recover costs incurred in: (1) the future installation, maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia to present an existing or probable hazard to persons and property; (2) the orderly and systematic replacement of, over a period of approximately three years, certain risers identified by the Commission's Staff as prone to failure; (3) Columbia's replacement of all priority pipe in its distribution system over a period of twenty-five years; (4) Columbia's replacement of company-owned and customer-owned metallic service lines identified by Columbia during the replacement of all priority pipe; and, (5) the installation of AMRDs on all meters located inside residences and small commercial facilities, as well as on inaccessible outside meters, served by Columbia.

Explanation Of Infrastructure Replacement Program

**Q. Please provide an explanation of the process proposed by Columbia for establishment of rates through the IRP mechanism.**

A. The Application filed by Columbia in Case No. 08-0073-GA-ALT provides for Columbia's filing by November 30 of each year its initial Rider IRP tariffs and supporting schedules for the Rider IRP to become effective the following May.

Columbia's Rider IRP filing will be comprised of three independent studies. This approach will provide for the development of independent revenue requirement studies for Columbia's AMRP; Riser and AMRD programs. Each revenue requirement study will be computed in the same manner, based on the costs of the specific program. The revenue requirement for each program will be allocated to each applicable rate schedule through the use of the specific allocation basis identified in the IRP Application filed in Case No. 08-0073-GA-ALT. The allocated revenue requirement for each rate schedule will then be divided by the actual bills sent to customers served under the applicable rate schedules during the previous calendar year to determine the rate impact per customer per month for that program. Rider IRP, for each rate schedule, will then be determined through the aggregation of the results calculated independently for each of the programs that comprise the IRP.

The supporting schedules will contain a combination of nine months of actual data and three months of projected data through December. By the following February 28 Columbia will file an updated application with schedules supporting the proposed IRP Rider based on actual costs accumulated through the previous December. These filings will include all accounting and billing record details needed by Staff to enable it to analyze and audit the schedules and issue a Staff Report of Investigation.

Subject to Commission approval, Rider IRP will become effective by May 1 following the February filing of an application as described herein unless: a) the Commission acts otherwise to delay the effective date of the IRP rider; b) the Staff determines that Columbia's application to increase Rider IRP is unjust or unreasonable; or c) any other party granted intervention by the Commission files an objection that is not resolved to the satisfaction of the Commission.

**Q. Will this same process be used in subsequent years for adjustment of the IRP Tracker Rate?**

A. Yes. Columbia will revise Rider IRP each year through the use of a similar process with one addition. It will include a true-up in future filings of revenues estimated to revenues collected. By November 30, 2009, and succeeding Novembers, Columbia will file a pre-filing notice containing estimated IRP schedules for the IRP rider to become effective the following May. The estimated schedules will contain a combination of actual and projected data for the calendar year in which the pre-filing notice is filed. By the following February 28 Columbia will file an updated application with schedules supporting the proposed IRP rider based on the costs accumulated through the end of the calendar year ending December 31, as adjusted for the associated gross receipts tax obligation.

**Q. Has a similar process been previously adopted by the Commission?**

A. Yes. The Commission's Opinion and Order issued May 30, 2002 in Case No. 01-1228-GA-AIR, et al[1], adopted a Stipulation and Agreement, which, among other things, approved a similar process for the Cincinnati Gas & Electric Co.

**Q. How will Columbia account for its investment in its Infrastructure Replacement Program?**

A. Columbia's investment in its IRP will be capitalized in a sub-account of Account 101, Plant in Service. This investment will be retained in this account for consideration for recovery of and return on in future rate proceedings.

**Q. How will Columbia determine the value of its investment in its IRP for purposes of calculating the value of these assets for rate accounting and rate making purposes?**

A. This investment will be valued (capitalized) at Columbia's actual costs of replacement or repair where the work is performed by Columbia or its contractor.

**Q. Does the proposed tracker mechanism requested by Columbia is this case provide for return on and return of these capitalized investment in addition to related operation and maintenance expenses?**

A. Yes.

[1] Case Nos. 01-1228-GA-AIR, In the Matter of the Application of Cincinnati Gas & Electric Company for an Increase in Rates; Case No. 01-1478-GA-ALT, In the Matter of the Cincinnati Gas & Electric Company for Approval of an Alternate Rate Plan for Gas Distribution Service; and Case No. 01-1539-GA-AAM, In the Matter of the Cincinnati Gas & Electric Company for Approval to Change Accounting Methods.

**Q. Please summarize the various types of costs for which Columbia seeks recovery through the IRP Rider.**

A. The IRP Rider mechanism for which Columbia requests Commission approval in this proceeding provides for a return on and return of its investment in the IRP and related costs such as deferred program operation and maintenance expenses; deferred depreciation expense; deferred property taxes; post-in service carrying costs; and related gross receipts taxes.

**Q. What types of operation and maintenance expenses will Columbia seek recovery of through the IRP Tracker?**

A. The rates established through this IRP process will provide for recovery of those amounts deferred by Columbia in accordance with its application filed in Case No. 08-0074-GA-AAM.

**Q. How will Columbia account for operation and maintenance expenses to be deferred in the future in accordance with Columbia's application filed in Case No. 08-0074-GA-AAM?**

A. These expenses will be recorded in special sub-accounts of 182 – Other Regulatory Assets or recovery through future IRP filings.

**Q. What is the proposed treatment of these deferred operation and maintenance expenses in Columbia's IRP tracker filings?**

A. Columbia's IRP tracker filings will provide for the recovery of all deferred operation and maintenance expenses for each calendar year over a one year period. The use of a one-year period for recovery of its deferred operation and maintenance expenses was selected since these expenses are anticipated to be incurred by Columbia, on an ongoing basis, over the life of the programs.

**Q. What is PISCC and why should Columbia be permitted recovery of these charges over the life of the IRP asset upon which they are incurred?**

A. PISCC charges are interest costs incurred by Columbia between the time the asset is placed into service for customer use and the time Columbia starts to earn a return on its investment. PISCC shall be calculated and deferred on all investment between the dates the property was placed into service and the date recovery of the investment commences[2]. The PISCC rate shall be determined annually based on the Columbia Gas of Ohio's weighted cost of debt. The PISCC rate shall be exclusive of the equity component and there will be no compounding of PISCC. PISCC shall be identified and segregated into special sub-accounts of Account 101 – Plant in Service until such amounts on Columbia's books are reviewed and verified by Staff during its investigation in an IRP or base rate case proceeding. It is appropriate to account for these costs in this manner for recovery through the IRP mechanism since these are program costs from which customers benefit.

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[2] The in-service date for the determination of PISCC on plant acquired through the reimbursement of customers will be the date that reimbursement is remitted to a customer.

**Q. How will PISCC be recognized in the development of the IRP filings?**

A. The *IRP* recovery provides for recovery of these costs over the life of the asset associated with the costs that were incurred.

**Q. Why is it appropriate for Columbia to defer for recovery of deferred depreciation expense on its investment in the IRP?**

A. These are costs incurred by Columbia from which customers benefit that would result in a reduction in Columbia earnings absent this treatment. Columbia witnesses Bohrer and Roy discuss the customer benefits.

**Q. What is the basis upon which deferred depreciation costs will be deferred and what depreciation rates will be utilized?**

A. Deferred depreciation expense shall be calculated each month based on Columbia's average investment in the IRP at the applicable Commission-approved depreciation rate(s) and recorded in special sub-accounts of 182 – Other Regulatory Assets.

**Q. Will the Rider IRP filings provide for recovery of deferred depreciation expense over the life of the asset(s) upon which the depreciation is determined?**

A. Yes.

**Q. Why is it appropriate for Columbia to defer for recovery through the IRP mechanism property taxes to be paid on its investment in the IRP?**

A. These are costs incurred by Columbia from which customers benefit that would result in a reduction in Columbia earnings absent this treatment. These costs would not have been incurred by Columbia absent its implementation of the IRP.

**Q. What is the basis upon which deferred property taxes will be determined and what tax rate will be utilized?**

A. Deferred property tax expense shall be calculated each month based on Columbia's previous December 31 plant balance at Columbia's current composite property tax rate and recorded in special sub-accounts of 182 – Other Regulatory Assets on 1/12 basis each month.

**Q. Will Columbia's Rider IRP filings provide for recovery of deferred property tax expense over the life of the asset(s) upon which determined?**

A. Yes.

**Q. Will Columbia's proposed Rider IRP provide for recovery of its additional gross receipts tax obligation if the Commission approves its request for establishment of a gross receipts tracker applicable to total bill?**

A. No. Columbia will recover gross receipts tax incurred through its IRP through the Gross Receipts Tracker. This conclusion is based on the assumption that the Commission's approval of this tariff change for establishment of the Gross Receipts Tracker as proposed is provided for in the Commission's Opinion and Order issued in Case No. 08-0072-GA-AIR. Columbia's Rider IRP will have to provide for recovery of the additional gross receipts tax obligation absent the Commission's approval of the proposed change.

**Q. How will the responsibility for the revenue requirement be distributed between the rate schedules?**

A. Columbia will propose the recovery of IRP costs from customer classes based on cost incurrence. Individual program costs will be allocated to rate schedules to be converted to a monthly fixed charge through the division of the allocated costs by the applicable annual billings for the most recent calendar period. This impact on individual rate schedules for each program will then be aggregated for determination of Rider IRP with cost responsibility to the individual rate classes being assigned as follows:

| Program | Cost Allocation Basis[3] | Rate Schedule(s) Allocated |
|---|---|---|
| Replacement of Risers Prone to Failure. | Account 380 - Investment in Service Lines | SGS, SGTS, FRSGTS<br>GS, GTS, FRGTS |
| Assumption of Financial Responsibility for Repair or Replacement of Customer-owned Service Lines | Account 380 - Investment in Service Lines | SGS, SGTS, FRSGTS<br>GS, GTS, FRGTS |
| Accelerated Main Replacement Program | Account 376 - Investment in Mains | All Rate Schedules |
| Installation of AMR Devices | Account 381 - Meters | SGS, SGTS, FRSGTS<br>GS, GTS, FRGTS |

**Q. What is the purpose of the Section G?**

A. Pursuant to Rules 4901:1-19(C)(2)(h) and (i), Ohio Administrative Code, a company filing an alternative rate plan under Section 4929.05, Ohio Revised Code, is required to submit comparable projected financial data to that contained in Section F of the Commission's Standard Filing Requirements, throughout the proposed term of the rate plan under the assumptions the plan is adopted, and under the assumption that the plan is not adopted. Columbia's Request for Waivers, which was approved by the Commission on March 5, 2008, included a request for modification of this requirement to the extent that comparable "Section G" schedules be provided through the end of the 5-Year financial plan period with full revenue requirements study being provided for the full 25 year term of the proposed Infrastructure Replacement Program. Revenue from Columbia's proposed IRP program will not start being received until May 1, 2009 at the earliest date. As

[3] The plant investment used for allocation of costs will be that set forth in Exhibit E-3.2 in Columbia's rate case application.

a result all "G" schedules will only be provided for the calendar years 2009 through 2012 – which is the end of Columbia's current 5-year planning period.

As explained earlier, Columbia's IRP is comprised of an AMRP, Riser, and AMRD programs. Schedules G-1 through Schedule G-4 provide the measurement of the impact of the IRP, under the assumption the plan is approved and the plan is not approved, through the aggregation of the impact of each of three programs that comprise the IRP. Schedule G-5 shows the development of the revenue requirement for the AMRP for the term of the program. Schedule G-5 reflects the use of the term "Section" (Section I – Section XV) in addition to "Schedule" as a means to identify each specific section that comprises Schedule G-5. The identification of individual sections was required for the purpose of providing through testimony a detailed description of the development the AMRP revenue requirement. For example, Schedule G-5, Section XV, provides a list of the assumptions used while Schedule G-5, Section I, shows the Development of Rate Base and Revenue Requirement for the AMRP. Schedule G-6 shows the development of the revenue requirement for Columbia's Riser Program with Schedule G-7 showing the development of the AMRD revenue requirement.

**Q. Was the rate base and revenue requirement for the individual programs that comprise the IRP computed in the same manner?**

A. Yes. Columbia has proposed the use of the same formulas and accounting for determination of individual revenue requirements for each program.

**Q. Why has Columbia elected to compute individual revenue requirements for each program given the fact the revenue requirement calculation will be performed in the same manner for each program?**

A. The development of the revenue requirement for each program independently better provides Columbia with the ability to allocate the costs to those customers that benefit from that program.

**Q. Please describe Schedule G-1.**

A. Schedule G-1 shows projected income statements for each of the calendar years 2009 through 2012 .These income statements reflect the Commission's approval of the alternative rate plan as requested. The source of the data used for preparation of Schedule G-1 is Columbia's 5-Year Financial Plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case;
The additional revenue produced by the alternative rate plan; and
The adjustment of expenses which are a function of revenue.

**Q. What is Schedule G-1A?**

A. Schedule G-1A shows for comparative purposes projected income statements for the calendar years 2009 through 2012. These income statements reflect the assumption that the alternative rate plan is not approved by the Commission. The source of the data used for preparation of Schedule G-1A was again Columbia's 5-Year financial plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case; and
The adjustment of expenses which are a function of revenue.

The impact of the Commission's approval of the alternative rate plan on gross revenue and operating income can be determined through a simple comparison of Schedules G-1 and G-1A.

**Q. Please explain Schedule G-2.**

A. Schedule G-2 shows the projected rate base for each of the calendar years 2009 through 2012 if the alternative rate plan is approved. Columbia selected the midpoint of the calendar year for determination of rate base. The decision to use the midpoint was made to provide all parties with the ability to compute a rate of return based on the average investment in place to serve customers during each of the calendar years. The source of the information used to compute rate base was Columbia's 5-Year financial plan. Following is list of key assumptions used in the development of the original cost rate base for each of the calendar years:

Net Plant Investment is based on the average of the beginning and ending balances.
No change in the Working Capital Allowance from that requested in the rate case.
The change in Other Rate Base Items results from the change in deferred taxes.

**Q. What is Schedule G-2A?**

A. Schedule G-2A shows for comparative purposes a projected original cost rate base for the calendar years 2009 through 2012 if the alternative rate plan is not approved. This schedule is identical to G-2 because this investment in Columbia's system must be made regardless of the type of revenue recovery mechanism approved by Commission.

**Q. Please describe Schedule G-2.1.**

A. Schedule G-2.1 shows the projected plant in service for each major property grouping for each of the calendar years 2009 through 2012 if the alternative rate plan is approved.

**Q. What is Schedule G-2.1A?**

A. Schedule G-2.1A shows the projected plant in service, by major property grouping, for the calendar years 2009 through 2012 if the alternative rate plan is not approved. This schedule is identical to G-2.1 because Columbia must make this investment in its system regardless of the type of revenue recovery mechanism approved by Commission.

**Q. Please describe Schedule G-3.**

A. Schedule G-3 shows the projected capital structure of Columbia Gas of Ohio at the mid-point of each of the calendar years 2009 through 2012 if the alternative rate plan is approved. The source of the information used for development of this schedule is Columbia's 5-year financial plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case;
The additional revenue produced by the alternative rate plan; and
The adjustment of expenses which are a function of revenue.

**Q. What is Schedule G-3A?**

A. Schedule G-3A shows for comparative purposes Columbia Gas of Ohio's projected capital structure at the date certain for the calendar years 2009 through 2012 if the alternative rate plan is not approved. The source of the information used for development of this schedule is Columbia's 5-year financial plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case;
The adjustment of expenses which are a function of revenue; and
No change in current tax rates.

The impact of the Commission's approval of the alternative rate plan on equity and short-term debt can be determined through a simple comparison of Schedules G-3 and G-3A.

**Q. Please describe Schedule G-4.**

A. Schedule G-4 is a projected statement of changes in financial position for each of the calendar years if the alternative rate plan is approved. The source of information used in the development of this schedule was Columbia's 5-year financial plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case;
The additional revenue produced by the alternative rate plan;
The adjustment of expenses which are a function of revenue; and.
Reduction of short-term debt by the change in net income.

**Q. What is Schedule G-4A?**

A. Schedule G-4A shows for comparative purposes a statement of changes in financial position for each of the calendar years 2009 through 2012 if the alternative rate plan is not approved. The source of the information used for development of this schedule is Columbia's 5-year financial plan which has been adjusted as follows:

The addition of the $87.8 million requested in the rate case.
The adjustment of expenses which are a function of revenue.

The impact of the Commission's approval of the alternative rate plan on net income and short-term debt can be determined through a simple comparison of Schedules G-4 and G-4A.

**Q. What is the purpose of Schedule G-5?**

A. This schedule shows the projected impact of Columbia's proposed AMRP segment of the Infrastructure Replacement Program for the term of the program. Schedule G-5 provides for the computation of the annual impact of the AMRP through a study developed on a rate making basis and the determination of the projected impact of that change in revenue requirement on customers for the term of the program. Schedule G-6 is comprised of following:

| Section | Description |
|---|---|
| 1 | Computation of Revenue Requirement |
| 2 | Plant Additions |
| 3 | Cumulative Plant Additions |
| 4 | Cost of Removal |
| 5 | Retirements |
| 6 | Annual Provision for Depreciation |
| 7 | Computation of Deferred Depreciation & Amortization |
| 8 | Computation of Post-In-Service Carrying Charges |
| 9 | Computation of Deferred Income Taxes |
| 10 | Annualized Depreciation on Retirements |
| 11 | Computation of Annualized Property Taxes |
| 12 | Computation & Amortization of Deferred Property Taxes |
| 13 | Flow-Through of O& M Savings |
| 14 | Computation of Projected Impact Per Customer |
| 15 | Assumptions Used In Preparation of Study |

**Q. Please describe Schedule G-5, Section I.**

A. Section I is a summary of the revenue requirement for the term of the IRP. The revenue requirement shown in Section I, for each year, is the level of recovery to become effective May 1 of the calendar year in which it is shown. The rate base upon which the return and related taxes are computed in development of the revenue requirement is investment made by Columbia through December 31 of the prior calendar year.

**Q. What are the various components of revenue requirement shown in Section I?**

A. The revenue requirement includes return on investment and related taxes; depreciation; property taxes; and operation and maintenance expenses.

**Q. What rate of return was used in the development of revenue requirement?**

A. The rate of return used for development of the revenue requirement was 9.12%. This is the return requested by Columbia in the rate case Application and supported by the testimony of Mr. Moul.

**Q. Will the rate of return used for calculation of the revenue requirement be changed to reflect the return authorized by the Commission in this rate case if the Commission issues an order that provides for the approval of rate of return different from that requested by Columbia?**

A. Yes. Columbia's IRP proposal provides for the use of a rate of return based on the capital structure and cost of capital authorized by the Commission in this case.

**Q. What do you mean by "Pre-tax Rate of Return?"**

A. Pre-tax rate of return is the rate of return further adjusted for impact of associated federal income taxes. The pre-tax rate of return provides for recognition of the fact that Columbia must pay federal income taxes on the equity component. Recognition of this obligation to pay federal taxes on equity is provided for through the multiplication of the weighted cost of equity by 53.846%, which is the ratio of federal tax to net income. The development of the pre-tax rate of return is shown at the bottom of each of the pages that comprise Section I.

**Q What is Deferred Depreciation Amortization?**

A. This is the amortization of depreciation deferred by Columbia between the time the asset was placed into service and recovery of asset commences.

**Q. How was the amount computed for inclusion in revenue requirement?**

A. This amount was computed through the multiplication of the balance at December 31 of previous year by the applicable depreciation rate approved by the Commission.

**Q. What is annualized depreciation expense?**

A. Annualized depreciation expense is the expense that Columbia will incur during the twelve months the new IRP rate will be in effect. This expense was computed through the multiplication of plant in service at December 31 of the previous year by the applicable depreciation rate approved by the Commission.

**Q What is Deferred Property Tax Expense Amortization?**

A. This is the amortization of property taxes deferred by Columbia between the time the asset was placed into service and recovery of asset commences.

**Q. How was amount computed for inclusion in revenue requirement?**

A. This amount was computed through the multiplication of the balance at December 31 of the previous year by the applicable depreciation rate approved by the Commission.

**Q. What is annualized property tax expense?**

A. Annualized property tax expense is the ongoing property tax expense that Columbia will incur during the twelve months the new IRP rate will be in effect. This expense was computed through the multiplication of the assessed value of plant in service at December 31 of the previous year by the applicable property tax rate.

**Q. What is included in the operation and maintenance component of the revenue requirement?**

A. Operation and maintenance expenses will include expenses incurred through the notification and education of customers. In addition, this component will provide for the pass through to customers of all reductions in costs directly related to the program such as the reduction is maintenance costs produced by the replacement of Priority Pipe (as defined in witness Roy's testimony) and leak repair costs.

**Q. What is basis for inclusion of the costs in the development of the revenue requirement?**

A. Columbia's request for recovery of theses expenses is based on the fact that these are prudent, necessary, business related expenses directly resulting from implementation of the IRP.

**Q. Will Columbia's annual IRP filings provide for recognition of any reduction in other expenses?**

A. Yes. Columbia will recognize in the determination of the revenue requirement any reduction in annualized depreciation and property tax expenses resulting from the retirement of property replaced as well as any reductions in meter reading costs previously noted.

**Q. How will Columbia recover the deferred PISCC set forth in Section I?**

A. These costs will be capitalized and recovered as part of Columbia's expense. The PISCC amounts shown on this exhibit were to specifically identify of the impact of PISCC on the revenue requirement.

**Q. What are the various components of rate base shown in Section I?**

A. Rate base includes gas plant in service less reserve for depreciation; plus deferred depreciation and deferred property taxes; less deferred income taxes. All rate base items reflect the use of the cumulative balance at December 31 of the prior year.

**Q. What is the source of the Plant in Service balance(s) set forth in Section I?**

A. The Plant in Service balances contained in Section I were carried forward from Section III which shows the Cumulative Plant in Service balance at December 31 of each year. The Cumulative Plant in Service balance(s) set forth in Section III is the aggregation of annual investment in its IRP for each year shown in Section II. The source of Columbia's annual investment in the IRP was its current capital budget extended to reflect estimates beyond the term of the current budget provided by the Engineering Department.

**Q. What is the source of Reserve for Depreciation Balance(s) set forth in Section I?**

A. The Reserve for Depreciation balance(s) contained in Section I were carried forward from Section IV which shows computation of annual depreciation and Cumulative Reserve for Depreciation balance at December 31 of each year.

**Q. What is the source of Net Deferred Depreciation Balance(s) set forth in Section I?**

A. The Net Deferred Depreciation balance(s) contained in Section I were carried forward from Section VII which shows computation of the deferred depreciation each year and Cumulative Deferred Depreciation balance at December 31 of each year.

**Q. What is the source of Net Regulatory Asset – PISCC Balance(s) set forth in Section I?**

A. The Net PISCC balance(s) contained in Section I were carried forward from Section VIII which shows computation of the deferred PISCC; Cumulative Gross PISCC Balance; Annual Amortization of PISCC; Cumulative Amortized PISCC Balance(s); and Cumulative Net PISCC balance at December 31 of each year.

**Q. What is the source of Net Deferred Tax Balance(s) – Property Tax Balance(s) set forth in Section I?**

A. The Net Deferred Tax Balance(s) – Property Taxes contained in Section I were carried forward from Section XII which shows computation of the Deferred Property Taxes – Gross; Cumulative Deferred Property Taxes – Gross; Annual Amortization of Deferred Property Taxes; Cumulative Amortized Deferred Property Tax Balance(s); and Cumulative Net Deferred Property Taxes – Net FIT Offset at December 31 of each year.

**Q. What is the source of Deferred Taxes – Liberalized Depreciation set forth in Section I?**

A. The Deferred Taxes – Liberalized Depreciation contained in Section I were carried forward from Section IX which shows the computation of this non-investor source of funds through a determination of the impact of tax depreciation on federal income taxes with the cumulative balance for each December 31 being carried forward to Section I.

**Q. What is basis for inclusion of these items in the development of the rate base?**

A. Recognition of each of these items in the determination of rate base properly measures the net investment of Columbia' directly resulting from implementation of the IRP.

**Q. Please describe Section II.**

A. Section II shows, by calendar year, Columbia's projected investment in plant additions for the AMRP component of its IRP. The source of this information is Columbia's capital budget for 5-year financial plan estimates beyond the term of the current budget provided by the Engineering Department.

**Q. Please describe Schedule G-5, Section III**

A. Section III shows, by calendar year, Columbia's cumulative projected investment in plant additions for the AMRP component of its IRP. The source of this information is Section II.

**Q. Please describe Schedule G-5, Section IV.**

A. Section IV is a place holder in recognition of costs that may be incurred by Columbia resulting from the need to remove plant currently in service as part of a betterment process. It was included to illustrate Columbia's IRP filings will provide for recognition of this additional investment. Columbia's revenue requirement assumes no impact for the purpose of development of this study.

**Q. Please describe Schedule G-5, Section V.**

A. Section V is a place holder to recognize that Columbia's IRP filings will provide for the impact of retirements. These retirements will not have an impact on rate base because the impact of retirements is reflected in determination of both cumulative plant in service and cumulative reserve for depreciation. However, these retirements will result in a reduction in depreciation expense and property taxes that will be recognized in IRP filings and an equivalent reduction in the revenue requirement.

**Q. Please describe Schedule G-5, Section VI.**

A. Section VI shows the projected depreciation for each calendar year; cumulative reserve for depreciation; and annualized depreciation. Annual depreciation equals the sum of the average investment for the current year multiplied by the applicable depreciation rate, plus an amount determined through the multiplication of prior years' cumulative plant balance at December 31 by the applicable depreciation rate. The cumulative reserve for depreciation was determined through the addition of prior year end cumulative balance and the current year's depreciation. Annualized depreciation was determined through the multiplication of cumulative plant additions at December 31 of the prior year by the applicable depreciation rate.

**Q. Please describe Schedule G-5, Section VII.**

A. Section VII shows the projected deferred depreciation for each calendar year; the cumulative deferred depreciation; the amortization of the cumulative deferred depreciation; cumulative amortization of deferred depreciation; and the net deferred depreciation balance. Deferred depreciation for each calendar year is the sum of: (1) the multiplication of prior years plant additions by the applicable depreciation rate; (2) the division of the product of part (1) by 365; (3) the multiplication of the result of (2) by 120; plus the result of; (4) the division of current year plant additions by 2; and, (5) the multiplication of the result of (4) by the applicable depreciation rate. Cumulative deferred depreciation was determined through the addition of the prior year end cumulative deferred depreciation balance and the current year's deferred depreciation. The amortization of deferred depreciation for each calendar year is the product of the multiplication of the prior year end balance at December 31 by the applicable depreciation rate. Cumulative amortization of deferred depreciation was determined through the addition of the cumulative balance at the end of the prior year plus the current year amortization; with the net cumulative balance being the difference between the cumulative deferred depreciation – gross and the cumulative amortization of deferred depreciation.

**Q. Please describe Schedule G-5, Section VIII.**

A. Section VIII shows: (1) the gross PISCC amounts for each calendar year; (2) the cumulative PISCC balance at December 31 each year; (3) the amortization of PISCC; (4) the cumulative balance of amortized PISCC; and, (5) the net cumulative PISCC balance.

**Q. How was PISCC calculated for each calendar year?**

A. These amounts were calculated through: (1) multiplication of the previous year plant additions by the applicable cost of debt; (2) the division of the product of (1) by 365; (3) the multiplication of the result of (2) by 120; plus (4) the division of current year plant additions by 2; (5) the multiplication of the result of (4) by the applicable cost of debt; and, (6) the sum of the results of steps 3 and 5.

**Q. Was the cumulative PISCC balance for the current year determined through the addition of the prior year's December 31 cumulative balance and current year amount?**

A. Yes.

**Q. How was the amortization of PISCC for the calendar year calculated?**

A. The amortization of PISCC for each calendar year was calculated through the multiplication of the cumulative prior year end balance by the applicable depreciation rate.

**Q How was the cumulative amortized PISCC determined?**

A. The cumulative amortized balance was developed through the addition of the cumulative balance at December 31 of the prior year and the current year amount.

**Q How was the Net Cumulative amortized PISCC determined?**

A. The net cumulative amortized balance was developed through the subtraction of the cumulative amortized balance from the gross cumulative balance.

**Q. Please describe Schedule G-5, Schedule IX.**

A. Schedule IX shows the development of the Accumulated Deferred Tax Balance used in the development of rate base.

**Q. How was the cumulative deferred tax balance calculated?**

A. This balance was calculated through the addition of the balance at December 31 of the prior year and the current year change.

**Q. How was the change for each calendar year determined?**

A. The change was developed through the multiplication of the difference between current year tax depreciation and book depreciation by 35%.

**Q. Please describe Schedule G-5, Section X.**

A. Schedule X is place holder in recognition of the reduction in the revenue requirement produced by recognition of the impact of retirements on annualized depreciation and property taxes.

**Q. Please describe Schedule G-5, Section XI.**

A. Schedule XI shows the computation of annualized property taxes. This calculation reflects the calculation of assessed value and multiplication of assessed value by the projected composite property tax rate.

**Q. Please describe Schedule G-5, Section XII.**

A. Schedule XII shows: (1) gross deferred property taxes for each calendar year; (2) the balance of cumulative deferred property taxes at December 31 each year; (3) amortized deferred property taxes for each calendar year; (4) cumulative amortized deferred property taxes at December 31 each year; (5) net cumulative deferred property taxes before the recognition of an Federal Income Tax offset; and, (6) net cumulative deferred property taxes after the tax offset.

**Q. How was the deferred balance for each year calculated?**

A. The deferred balance for each year was determined through: (1) the division of the current year tax obligation by 365 and (2) the multiplication of the result by 120. Gross deferred property taxes were then developed through the addition of cumulative balance at December 31 of the prior and the current year deferral.

**Q. How was the amortization of the deferred tax balance for each year calculated?**

A. The amortization was determined through (1) the multiplication of the cumulative deferred balance at December 31 of the year before the previous year by the applicable deprecation rate; (2) the division of the product by 365; (3) the multiplication of the result by 120; plus (4) the multiplication of the prior December 31 cumulative balance by the applicable depreciation rate; (5) the division of the result by 365; (6) the multiplication of the result of 5 by 245; and, (7) the addition of the results obtained in (3) and (6).

**Q. Was the cumulative amortization determined through the addition of the prior December 31 balance and the current year amortization?**

A. Yes.

**Q. How was the net deferred property tax balance before recognition of the federal income tax offset determined?**

A. These balances were determined through the subtraction of the cumulative amortized balance from the gross cumulative deferred property tax balance.

**Q. Was the Deferred Property Taxes – Net FIT Offset calculated through the multiplication of Net Deferred Property Tax Balance by 65%?**

A. Yes.

**Q, Please describe Schedule G-5, Section XIII.**

A. Schedule XIII is a place holder included in recognition of anticipated reductions in operation and maintenance expenses produced by the IRP.

**Q. Please describe Schedule G-5, Section XIV.**

A. Schedule XIV shows the computation of the projected impact of the IRP program per customer.

**Q. What was the basis used for assignment of the revenue requirement?**

A. The basis used for allocation of the revenue requirement was the applicable gross plant in service contained in Mr. Feingold's Class Cost of Service Study.

**Q. How was this gross plant used to allocate the revenue requirement?**

A. The applicable gross plant investment for each rate schedule shown in Mr. Feingold's Class Cost of Service Study was used to develop allocation factors for each rate schedule through the division of the gross plant assigned the rate schedule by Mr. Feingold by the total of gross plant for all groups that benefit from the AMRP. The revenue requirement was then allocated to rate schedules through the multiplication of total revenue requirement by the applicable allocation factor.

**Q. How was the cost per customer per month developed?**

A. The cost per customer per month was developed through the division of the allocated revenue requirement by total number of bills for the applicable rate schedule.

**Q. Please describe Schedule G-5, Section XV.**

A. Schedule XV sets forth the key assumptions used in the development of each of the IRP studies.

**PROPOSED DEMAND SIDE MANAGEMENT PROGRAM ("DSM")**

**Q. Did include in your preparation of the "G" Schedule(s) the impact of Columbia's proposed DSM program?**

A. No. The Joint Stipulation and Recommendation filed in Case Nos. 04-221-GA-GCR, et al provides that Columbia will file an application, cooperatively developed by Columbia, OCC, Commission Staff and other interested stakeholders, by July 1, 2008, for approval of a comprehensive energy efficiency program for all residential customers. For this reason Columbia did not include the impact of the DSM program due to the fact is in the development stage with limited information available to identify the overall impact of the program.

**Q. Was Schedule G-7 calculated in the same manner as G-5?**

A. Yes.

**PROPOSED CHANGE IN ACCOUNTING METHOD**

**Q. Please describe the accounting changes provided for in the Amended Stipulation and Recommendation filed on December 28, 2007 in Case No. 07-478-GA-UNC.**

A. The accounting changes provided for in the Amended Stipulation and Recommendation filed by Columbia, Staff and OCC in Case 07-0478-GA-UNC are as follows:

a. Authorization for Columbia to capitalize its investment in risers and service lines as replaced, including those lines replaced by customers for which customers are reimbursed pursuant to the July 11 Entry in Case No. 04-478-GA-UNC and the Stipulation.

b. Authorization to record as a regulatory asset the related depreciation, incremental property taxes and PISCC to be recovered through the IRP Rider at later date.

c. Authorization to modify its accounting to provide for the deferral of customer notification and education expenses in special sub-accounts of Account 182-Other Regulatory Assets for recovery through the IRP.

d. The deferral of expenses that result from Columbia compliance with the Commission's directives in Case No. 05-463-GA-COI and its performance of the riser survey with the exception of certain costs identified in the Stipulation as costs incurred during the riser survey and riser and service line testing as costs for work performed in the field that, while not directly recommended by the Staff Report in Case No. 05-563-GA-COI, namely leak surveying and atmospheric corrosion testing, were economical and practical to perform while work crews were deployed in the field. The excluded costs consist of activities that would have been conducted in 2007 absent the riser survey and are required by Pipeline Safety Regulations.

**Q. Why does Columbia continue to request the aforementioned accounting treatment in Case No. 07-478-GA-UNC?**

A. The modification of Columbia's accounting as provided for the Amended Joint Stipulation and Recommendation filed in Case No. 07-478-GA-UNC provides customers with the numerous benefits identified in Columbia's Application filed in Case No. 07-478-GA-UNC through the provision of Columbia with authority required to account for and recover prudent, necessary business expenses in future IRP filings or rate case proceedings. Columbia continues to request approval of this accounting treatment because as of the date of the filing of this testimony the Commission has yet to act upon the stipulation filed in Case No. 07-478-GA-UNC.

**Q. Please describe the accounting changes requested by Columbia in Case No. 08-0074-GA-AAM.**

A. The accounting changes requested by Columbia in Case No. 08-0074-GA-AAM are as follows:

a. Approval of the authority to modify its accounting as set forth in the Amended Stipulation and Recommendation filed in Case No. 07-478-GA-UNC.

b. Authority to capitalize its investment resulting from the replacement of metallic service lines identified by Columbia during the replacement of all Priority Pipe, as well as the authority to assume financial responsibility for such repair or replacement of service lines;

c. Authority to capitalize and include for recovery through Rider IRP Columbia's investment made as part of its AMRP. This includes all investment made by Columbia through the replacement of Priority Pipe; the movement of meters located inside customer premises outside; and the replacement of all metallic service lines.

d. Authority for installation and capitalization of automatic meter reading devices on all meters located inside residences, as well as on inaccessible outside meters;

e. Authority to record as a regulatory asset for recovery through Rider IRP the related depreciation, incremental property taxes on all investments for which it requests a return on and return of its investment through Rider IRP between the date the property is placed into service and the date recovery of the investment commences. All deferred expenses shall be identified in a sub-account of Account 182, Other Regulatory Assets, and will not be subject to any carrying charges. Columbia further requests authority to accrue in Account 101, Gas Plant in Service, and Post-In-Service Carrying Charges on all investment between the dates the property was placed into service and the date recovery of the investment commences.

f. Authority to modify Columbia's accounting to provide for the deferral of customer education expenses related to the AMRP and AMRD programs in special sub-accounts of Account 182-Other Regulatory Assets for recovery through the Rider IRP.

g. Authority to modify Columbia's accounting to provide for the deferral of all DSM program expenses in special sub-accounts of Account 182-Other Regulatory Assets for recovery through the Rider DSM. DSM program expenses to be deferred will be those expenses incurred by Columbia through Columbia's implementation of comprehensive, ratepayer funded, cost-effective, energy efficiency programs made available to all residential and commercial customers during the years 2009 through 2011. Columbia will file an application, cooperatively developed by Columbia, Commission Staff, the OCC and other interested stakeholders by July 1, 2008 through which approval of a DSM program will be requested.

**Q. Why should the Commission approve the accounting treatment by Columbia requested in Case No. 08-0074-GA-AAM?**

A. The Commission's approval of Columbia's proposed accounting changes as provided for in Case No. 08-0074-GA-AAM will result in the numerous benefits produced by Columbia's IRP and DSM programs set forth in the testimony of other Columbia witnesses. Columbia's implementation of these programs will require the Commission's approval of the above-referenced accounting changes contained in the Amended Stipulation and Stipulation filed by the parties in Case No. 07-748-GA-UNC, as well as the additional changes requested in Case No. 08-0074-GA-AAM.

**Q. Please describe Supplemental Exhibit S-1.**

A. Schedule S-1 is multiple page document that shows Columbia's Five-Year Capital Expenditures Budget. Schedule S-1, Page 1 is a summary of capital expenditures for each calendar year (2008 – 2012) into various categories used by Columbia. These categories include New Business; Age and Condition (Replacement); Mandatory (Public Improvement); Support Service; and Corporate Capital Allocation. Schedule S-1, Page 2 through 4, set forth individual projects included in Columbia's expenditure budget with an estimated project costs greater of at least $250,000. The source of the information is Columbia's approved capital expenditures budget.

**Q. Please describe Schedule S-2.**

A. Schedule S-2 multiple page document that sets forth Columbia's Five Year Financial Plan Forecast for the period 2008 – 2012. This schedule includes, by calendar year the following:

Forecasted Income Statements
Forecasted Balance Sheets
Forecasted Changes in Financial Position
Assumptions

The source of the information used for preparation of these documents is Columbia Five Year Financial Plan.

**Q. Does this conclude your Prepared Direct Testimony?**

A. Yes, it does.

Columbia Exhibit No.

**BEFORE**
**THE PUBLIC UTILTIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service. | ) ) ) ) | Case No. 08-0072-GA-AIR |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges. | ) ) ) ) | Case No. 08-0073-GA-ALT |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods. | ) ) ) | Case No. 08-0074-GA-AAM |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Revise its Depreciation Accrual Rates. | ) ) ) | Case No. 08-0075-GA-AAM |

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**PREPARED DIRECT TESTIMONY OF**
**PAUL R. MOUL**
**ON BEHALF OF COLUMBIA GAS OF OHIO, INC.**

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- [ ] **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**
- [ ] **OPERATING INCOME**
- [ ] **RATE BASE**
- [ ] **ALLOCATIONS**
- [x] **RATE OF RETURN**
- [ ] **RATES AND TARIFFS**
- [ ] **OTHER**

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**March 17, 2008**

**BEFORE**

***THE PUBLIC UTILITIES COMMISSION OF OHIO***

| | | |
|---|---|---|
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service. | ) ) ) ) | Case No. 08-0072-GA-AIR |
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| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods. | ) ) ) | Case No. 08-0074-GA-AAM |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Revise its Depreciation Accrual Rates. | ) ) ) | Case No. 08-0075-GA-AAM |

**PAUL R. MOUL**
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Summary of the testimony dealing with the determination of Cost of Equity for Columbia Gas of Ohio, Inc.

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**March 17, 2008**

| GLOSSARY OF ACRONYMS AND DEFINED TERMS | |
|---|---|
| **ACRONYM** | **DEFINED TERM** |
| AFUDC | Allowance for Funds Used During Construction |
| $\beta$ | Beta |
| b | represents the retention rate that consists of the fraction of earnings that are not paid out as dividends |
| b x r | Represents internal growth |
| CAPM | Capital Asset Pricing Model |
| CCR | Corporate Credit Rating |
| CEG | Columbia Energy Group |
| DCF | Discounted Cash Flow |
| FERC | Federal Energy Regulatory Commission |
| FOMC | Federal Open Market Committee |
| g | Growth rate |
| GCR | Gas Cost Recovery Mechanism |
| IGF | Internally Generated Funds |
| LDC | Local Distribution Companies |
| Lev | Leverage modification |
| LT | Long Term |
| M&A | Merger and Acquisition |
| MLP | Master Limited Partnerships |
| MPL | Minimum pension liability |
| OCI | Other Comprehensive Income |
| PUC | Public Utility Commission |
| PUCO | Public Utilities Commission of Ohio |
| PUHCA | Public Utility Holding Company Act |
| r | represents the expected rate of return on common equity |
| Rf | Risk-free rate of return |
| Rm | Market risk premium |
| s | Represents the new common shares expected to be issued by a firm |

| GLOSSARY OF ACRONYMS AND DEFINED TERMS | |
|---|---|
| **ACRONYM** | **DEFINED TERM** |
| s x v | Represents external growth |
| S&P | Standard & Poor's |
| v | represents the value that accrues to existing shareholders from selling stock at a price different from book value |

## PREPARED DIRECT TESTIMONY OF PAUL R. MOUL

### INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A: My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

**Q. What is the purpose of your testimony?**

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Public Utilities Commission of Ohio ("PUCO" or the "Commission") should recognize in the determination of the revenues that Columbia Gas of Ohio, Inc. ("Columbia" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Attachments PRM-1 through PRM-14. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely. My testimony is based upon my first hand knowledge of Columbia consisting of information obtained from meetings with the Company's management and Company-specific data, which is widely disseminated within the financial community.

**Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?**

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.50%. As shown on Attachment PRM-1, I have presented the weighted average cost of capital for the Company, which is 9.12%. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and provides the Company with the ability to attract capital on reasonable terms.

**Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?**

A. The Company is wholly-owned subsidiary of Columbia Energy Group ("CEG"), which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). The Company is part of an integrated natural gas system which is comprised of five retail gas distribution companies serving 2.2 million customers in five states. NiSource was created on April 14, 1999, as part of the acquisition of CEG by NIPSCO Industries, Inc., the former name of NiSource. NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), Bay State

Gas Company and its subsidiary Northern Utilities, Inc., and other energy investments.

The Company provides natural gas distribution service to approximately 1.4 million customers located in the central portion of Ohio extending from Lake Erie to the Ohio River. Throughput to its customers in 2006 was represented by approximately 40% to residential customers, approximately 24% to commercial customers, and approximately 36% to industrial customers. Overall, throughput on the Columbia system consists of approximately 31% to sales customers and 69% to transportation customers. Columbia obtains its gas supplies from producers and marketers and transports this gas through eight interstate pipelines and one intrastate pipeline. The Company has storage arrangements with two storage providers to supplement flowing gas.

**Q. How have you determined the cost of common equity in this case?**

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for à natural gas utility, such as Columbia. In this regard, I have considered four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

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

A. The Commission should consider the ratesetting principles that I have set forth in Appendix B. In this regard, the Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, support reasonable credit quality, and allow the Company to raise capital on reasonable terms.

**Q. What factors have you considered in measuring the cost of equity in this case?**

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of ten utility companies. The proxy group consists of companies that: (i) are engaged in the distribution of natural gas or gas distribution and the delivery of electricity, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) operate in the New England, Middle Atlantic and South Atlantic regions of the U.S., (v) are not currently the target of a merger or acquisition, and (vi) in the case of the combination utilities, they do not have a significant amount of electric generation that is unregulated. The companies in the proxy group are identified on page 2 of Attachment PRM-3. I will refer to these companies as the "Proxy Group" throughout my testimony.

**Q. How have you performed your cost of equity analysis with the market data for the Proxy Group?**

A. I have applied the models/methods for estimating the cost of equity using the average data for the Proxy Group. I have not measured separately the cost of equity for the individual companies within the Proxy Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

**Q. Please summarize your cost of equity analysis.**

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

| | Proxy Group |
|---|---|
| DCF | 11.27% |
| RP | 11.47% |
| CAPM | 14.07% |
| Comparable Earnings | 13.90% |
| Average | 12.68% |
| Median | 12.69% |
| Mid-point | 12.67% |

Focusing upon the market model approaches of the cost of equity (i.e., DCF, RP and CAPM), the average equity return is 12.27% (11.27% + 11.47% + 14.07% = 36.81% ÷ 3). The results for the DCF and RP methods are 11.37% (11.27% + 11.47% = 22.74% ÷ 2). From all these measures, I recommend that the Commission set the Company's rate of return on common equity at 11.50%. My recommended cost of equity of 11.50% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events.

## NATURAL GAS RISK FACTORS

**Q. What factors currently affect the business risk of the natural gas utilities?**

A. The competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing and open access for gas transportation mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCR mechanism. Higher and volatile gas costs may result in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. While improved rate design can mitigate the impact of declining average use for small customers, the loss of load due to conservation, fuel switching or plant closures cannot be mitigated for large customers.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end-users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

**Q. Does the Company face competition in its natural gas business?**

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as Columbia, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

**Q. How does the Company's throughput to large volume users affects its risk profile?**

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. Test year throughput to the Company's industrial customers represents 33% of total throughput. Indeed, the Company's ten largest customers represent 33.6 million Mcf of throughput, or approximately 37% of the industrial class of customers. The business lines of these customers are in petroleum refining, chemicals, steel, glass, automotive assembly, education and food processing. Throughput to the manufacturing business segment is especially vulnerable in this economic environment. Large volume users, which have traditionally used transportation service, also have the ability to bypass the Company's system. The Company has identified 64.7 million Mcf of throughput that is susceptible to bypass. The Company has been able to offer special contracts to customers representing 63.6 million Mcf to avoid bypass. An additional 14.5 million Mcf is susceptible to fuel switching.

Success in this segment of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory. As these firms search for cheaper labor, or go out of business, load can be lost for large customers, as well as the out-migration of high paying jobs associated with these customers. This puts fixed cost recovery at risk. Some of that loss can be offset by economic growth, but the Company faces potential net negative growth and lost margins.

Q. **Please indicate how its construction program affects the Company's risk profile.**

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company had 3,995 miles (or approximately 20%) of its distribution mains constructed of cast iron, wrought iron and unprotected steel pipe as of year-end 2006. Also, the Company has 174,002 (or approximately 13%) of its services constructed of unprotected steel. The Company projects its construction expenditures will be approximately $677,900,000 in the period 2008-2012. Over this five-year period, these capital expenditures will represent approximately 57% ($677,900,000 ÷ $1,187,243,000) of its net utility plant at December 31, 2007. Given its large construction expenditures forecast for the future, the Commission should be supportive of the Company's cash flow needs by adopting its proposal for a 25-year program of infrastructure rehabilitation. A fair rate of return represents a key to a financial profile that will provide the

Company with the ability to raise the capital necessary to meet its capital needs on reasonable terms.

**Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?**

A. Yes. Most of the Company's residential customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. For these sales, the Company's revenues are subject to variations caused by weather abnormalities. In addition, the Company has determined that its residential margin (both customer charge and volumetric) has declined steadily as described in the pre-filed direct testimony of Mr. Russell A. Feingold. These declining margins are reflective of lower average use per residential customer. As a result of this situation, the Company is proposing to implement a straight fixed variable rate design.

**Q. Does your cost of equity analysis and recommendation take into account the Company's conservation program and rate design proposal?**

A. Yes. As part of this case, the Company is proposing to implement an aggressive conservation program, and implement rate design changes. My cost of equity analysis that provides an 11.50% rate of return on common equity takes these measures into account.

**Q. How have you addressed this issue?**

A. The gas distribution companies in my Proxy Group already have various forms of regulatory mechanisms that are intended to stabilize revenue, which in some cases are directed to temperature variations and others to margin reconciliation. These regulatory mechanisms are designed to assure recovery of the fixed costs for the gas distribution companies. Many of these mechanisms are intended to address the same issues as the Company's proposal of straight fixed variable rate design. Some of the combination companies also have these mechanisms, or they are proposing them. As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items such as infrastructure investment. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of tracking mechanisms in the LDC business.

**Q. How should the Commission respond to the issues facing the natural gas utilities and in particular Columbia?**

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to the risk related to earnings attrition even with its proposed change in rate design, since costs are rising each year. This leaves the Company in the situation that its ability to earn the allowed return is in jeopardy even with enhanced rate design.

**FUNDAMENTAL RISK ANALYSIS**

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

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

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

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Attachment PRM-3.

**Q. What criteria did you employ to assemble the Proxy Group?**

A. I previously enumerated the criteria that I employed to assemble the Proxy Group.

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

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

**Q. How do the bond ratings compare for Columbia, the Proxy Group, and the S&P Public Utilities?**

A. Presently, Columbia has no bond rating because its debt is owned by an affiliate. The corporate credit rating ("CCR") for Columbia's ultimate parent, NiSource, is BBB- from Standard and Poor's Corporation ("S&P"), and the Long Term ("LT") issuer rating is Baa3 from Moody's Investors Services ("Moody's"). The S&P rating for NiSource was recently downgraded on December 18, 2007. S&P noted that while the business risk profile of NiSource was "Excellent," it rated its financial profile as "Aggressive." In making its credit assessment, S&P noted: "The rating on NiSource and its subsidiaries reflects NiSource's newly aggressive capital-spending program, which will result in negative free cash flow and increased debt levels, reversing years of deleveraging." The ratings for NiSource are at the bottom of the investment grades. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Proxy Group is an A from S&P and A2 from Moody's. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

**Q. How do the financial data compare for Columbia, the Proxy Group, and the S&P Public Utilities?**

A. The broad categories of financial data that I will discuss are shown on Attachments PRM-2, PRM-3, and PRM-4. The data cover the five-year period 2002-2006. The important categories of relative risk may be summarized as follows:

<u>Size.</u> In terms of capitalization, Columbia is approximately one-quarter of average size of the Proxy Group, and much smaller than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm.

<u>Market Ratios.</u> Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to

say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for Columbia because NiSource owns its stock. The five-year average price-earnings multiple for the Proxy Group was fairly similar to that of the S&P Public Utilities. The five-year average dividend yields were somewhat higher for the Proxy Group as compared to the S&P Public Utilities. The average market-to-book ratios were fairly similar for the Proxy Group and the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 60.5% for Columbia, 50.3% for the Proxy Group, and 41.2% for the S&P Public Utilities. For rate of return purposes in this case, the NiSource consolidated capital structure will be used, which contains a larger proportion of debt capital as compared to the Columbia capital structure.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common

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

equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.332 (7.1% ÷ 21.4%) for Columbia, 0.047 (0.5% ÷ 10.7%) for the Proxy Group, and 0.159 (1.7% ÷ 10.7%) for the S&P Public Utilities. Columbia has greater risk due to its higher earnings variability as compared to the Proxy Group and S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 87.8% for Columbia, 88.4% for the Proxy Group, and 84.0% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC)") was 7.11 times for Columbia, 3.71 times for the Proxy Group, and 2.89 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not

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

been a significant concern for Columbia, the Proxy Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 95.3% for Columbia, 89.3% for the Proxy Group, and 110.1% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. [3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .84 as the average for the Proxy Group (see page 2 of Attachment PRM-3), and .95 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-4).

**Q. Please summarize your risk evaluation.**

A. The risk of Columbia parallels that of the Proxy Group in certain respects. However, its much more variable earned returns suggest higher risk for the Columbia. On balance, the risk factors average out, indicating that some risk

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[3] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix I. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

factors are higher, some are lower, and others are about the same, which indicates that the cost of equity for the Proxy Group would provide a reasonable basis for measuring the Company's cost of equity for this case.

## CAPITAL STRUCTURE RATIOS

**Q. Please explain the selection of capital structure ratios for Columbia.**

A. Usually, where the operating public utility raises its own debt directly in the capital markets, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. As all of the Company's long-term debt is owned by an affiliate, the historical practice of the Commission has been to employ the parent company consolidated capital structure ratios. This approach has been followed in this case for Columbia.

**Q. Does Attachment PRM-5 provide the capitalization and capital structure ratios of NiSource Inc.?**

A. Yes. Attachment PRM-5 presents the parent company's capitalization and related capital structure ratios. The December 31, 2007 capitalization corresponds with the date certain in this case. I should note that there is a small difference in the NiSource common equity account shown on my Attachment PRM-5 and the Company's Schedule D-1 that was filed previously. In my Attachment PRM-5, I have the final retained amount for NiSource that reflects a late accounting adjustment that was reflected in the Form 10-K that was filed with the SEC. The final retained amount shown on Attachment PRM-5 had no affect on the Company's overall rate of return that is proposed in this case. On attachment PRM-5, I have made two adjustments to the NiSource capital structure for ratesetting purposes in this case. I have adjusted the parent company's capital structure to remove the pollution control bonds of Northern Indiana Public Service Company ("NIPSCO"), the debt of non-regulated subsidiaries, and the accumulated other comprehensive income ("OCI").

**Q. Please describe these adjustments.**

A. Adjustments are required when using the NiSource consolidated capital structure for ratesetting purposes. The eliminations that are necessary include: (i) the removal of the tax exempt debt issued on behalf of NIPSCO that was used for the construction of environmental control facilities at its electric generation plants, (ii) elimination of the debt issued by the non-regulated subsidiaries of NiSource, and (iii) the removal of the accumulated OCI from the common stock equity,.

The NiSource consolidated capital structure includes debt issued by governmental authorities that was lent to NIPSCO. The pollution control bonds issued by NIPSCO totaled $254 million at December 31, 2007 and should be excluded in computing capital structure for this case. These securities are obligations that provided funding for the construction by NIPSCO of specific pollution control facilities. The debt was issued by a government authority and the proceeds were held by a trustee and were dispersed to NIPSCO under a loan agreement between the government entity and NIPSCO for the payment of the construction costs of certain pollution control facilities. That is to say, these debt obligations were used exclusively to finance specific assets that are unassociated with Columbia.

In addition, the debt of the non-regulated subsidiaries must be removed from the NiSource consolidated capital structure. The debt of NDC Douglas Properties (a real estate endeavor) in the amount of $13 million at December 31, 2007 is unrelated to utility operations.

I have also removed the accumulated OCI from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. While the accumulated OCI for NiSource has its roots in many of these categories, the majority of the balance of OCI relates to MPL and unrealized gains on cash flow hedges. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base of any of the NiSource utility subsidiaries. As required by SFAS Nos. 87 and 130, a MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of the trust fund assets. As such, MPL arises from a decline in stock market values and a decline in interest rates, which reduces the value of the trust fund assets and increases the present value calculation of the pension benefit obligation. Hence, the accumulated OCI must be excluded from the common stock equity, because it represents a contingent liability. In addition, NiSource uses a variety of derivative instruments (exchange traded futures and options, physical forwards and options, and financial commodity swaps) to effectively manage its commodity price risk. If certain conditions are met, a derivative may be specifically designated as a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, or a hedge of the exposure to variable cash flows of a forecasted transaction. For subsidiaries that utilize derivatives for cash flow hedges, unrealized gains and losses are recorded to OCI and are recognized in earnings concurrent with the disposition of the hedged risks. Most of this balance is reflected on the balance sheets of non-regulated companies. In order to hedge the anticipated future purchase of gas from the gas supplier, Columbia Energy Services, a wholly owned subsidiary of Columbia Energy Group, entered into commodity swaps priced at the locations designated for physical delivery. These swaps are designated as cash flow hedges of the anticipated purchases. As such, these unrealized gains attributable to non-regulated activities are appropriately excluded from the capital structure for setting regulated rates of return.

**Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?**

A. I will adopt the Company's test year-end capital structure ratios of 50.49% long-term debt and 49.51% common equity. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

## COST OF LONG-TERM DEBT

**Q. What cost rate have you assigned to the debt portion of the NiSource capital structure?**

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on Attachment PRM-6, I have computed the actual embedded cost rate of long-term debt at December 31, 2007. In calculating the embedded cost of long-term debt, I have recognized the cost associated with the early redemption of the high cost CEG debentures that were called prior to maturity. To call that debt, CEG paid the debentures holders a premium to surrender those debt obligations prior to maturity. These premiums represented an investment made by CEG to reduce its overall cost of capital. As such an adjustment is required for the Company to recover its costs so customers could receive the cost savings resulting from these refinancings. Because the reduced interest costs are reflected in the lower cost of capital, it is necessary that the Company recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium and the amortization of the premium provides the return of that investment as a part of the embedded cost rates of capital.

I will adopt the 6.79% embedded cost of long-term debt at December 31, 2007, as shown on Attachment PRM-6. This rate is related to the amount of long-term debt shown on Attachment PRM-6 which provides the basis for the 50.49% long-term debt ratio.

## COST OF EQUITY – GENERAL APPROACH

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

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships between Columbia, the Proxy Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity indicated by the models.

It also is important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Proxy Group and have arrived at a cost of equity of 11.50% for Columbia.

## DISCOUNTED CASH FLOW ANALYSIS

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

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

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

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

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

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended January 2008, the monthly dividend yields of the Proxy Group are shown graphically on Attachment PRM-7. The monthly dividend yields shown on Attachment PRM-7 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ending January 2008, the average dividend yield was 3.82% for the Proxy Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 3.88% and 3.95%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.88% for the Proxy Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs, while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Proxy Group. I have adjusted the six-month average dividend yield in three different, but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix E. That adjusted dividend yield is 4.01% for the Proxy Group.

**Q. Please explain the underlying factors that influence investor's growth expectations.**

A. As noted previously, investors are interested principally in the future growth of its investment (i.e., the price per share of the stock). As I explain in Appendix E, future earnings per share growth represents its primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis also can be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

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

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing its capital gains expectations with its dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

**Q. What company-specific data have you considered in your growth rate analysis?**

A. I have considered the growth in the financial variables shown on Attachment PRM-8 and PRM-9. The bar graph provided on Attachment PRM-8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Proxy Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM-8, historical growth in earnings per share was in the range of 3.50% to 4.17% for the Proxy Group.

Attachment PRM-9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Attachment PRM-9 for the Proxy Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

**Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?**

A. Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

**Q. What specific evidence have you considered in the DCF growth analysis?**

A. As to the five-year forecast growth rates, Attachment PRM-9 indicates that the projected earnings per share growth rates for the Proxy Group are 6.41% by IBES/First Call, 6.82% by Zacks, 6.21% by Reuters/Market Guide, and 6.37% by Value Line. The Value Line projections indicate that earnings per share for the Proxy Group will grow prospectively at a more rapid rate (i.e., 6.37%) than the dividends per share (i.e., 4.15%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

**Q. What conclusion have you drawn from these data?**

A. Ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm; however, the circumstances of the Proxy Group mandate that the greater emphasis be placed upon projected earnings per share growth. Rather, projections of future earnings growth provide the principal focus of investor expectations. Such projections will accommodate the rise in commodity prices and the trend toward tariff provisions that accommodate the decoupling of revenues from sales. Indeed, for natural gas distribution utilities, they have entered a new transition phase which could impact the future growth in earnings. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth.[4] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represent a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First

[4] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould.

Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company Act, merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell its shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth, as shown on Attachment PRM-9 provide a range of growth rates of 6.21% to 6.82%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 6.25% is within the array of earnings per share growth rates shown by the analysts' forecasts. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As I previously indicated, the restructuring and consolidation now taking place in the utility industry will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts and will enhance the growth prospects for the future. As such, a 6.25% growth rate will accommodate all these factors.

**Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?**

A. Only if the capital structure ratios are measured with the market value of debt and equity. If book values are used to compute the capital structure ratios, then an adjustment is required.

**Q. Please explain why.**

A. If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and use those results in computing the weighted average cost of capital with a book value capital structure, those results will not reflect the degree of financial risk associated with the capital structure shown by the market capitalization. When the price diverges from book value, the potential exists for a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity upward to make the return consistent with the book value capital structure. Provisions for this risk difference were made by the Pennsylvania Public Utility Commission in the following cases:

- January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-00016339 -- 60 basis points adjustment.
- August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750 -- 80 basis points adjustment.
- January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis points adjustment.
- August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis points adjustment.
- December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-00049255 -- 45 basis points.
- February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398 -- 70 basis points adjustment.

It must be recognized that in order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification. As I will explain later in my testimony, the results of the DCF model can be modified to account for differences in risk when the book value capital structure contains more financial leverage than the market value capital structure.

**Q. Is your leverage adjustment dependent upon the market valuation or book valuation from an investor's perspective?**

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P+g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Proxy Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilizes the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Since the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus a term(s) reflecting the increase in financial risk resulting from the use of leverage in the capital structure. Multiple terms are used in the case of both debt and preferred stock. The resulting return is the one that is necessary for the utility to earn on its own book value capital structure to reflect the financial risk that varies from the return that applies to the market value capital structure.

**Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?**

A. No. My leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. My leverage adjustment deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from its cost of equity. Stock prices above book value are common for utility stocks, and indeed non-regulated stock prices exceed book values by even greater margins. In this regard, according to the Barron's issue of February 11, 2008, the major market indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of 2.55 times book value which is below the market multiple of other indices. For example, the S&P 500 index trades at 2.64 times book value, the S&P Industrial index is at 3.22 times book value, and the Dow Jones Industrial index is at 3.66 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of its cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

**Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's capitalization?**

A. The capital structure ratios measured at the utility's book value show more financial leverage, and higher risk, than the capitalization measured at its market values. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different -- in this instance, much lower -- from that shown by the book value capitalization. Hence, it is necessary to develop a cost of equity that reflects the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Proxy Group that is related to the 52.33% common equity ratio using book value has higher financial risk than the 65.68% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

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

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. Simply stated, my leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. There can be no dispute that a firm's financial risk varies with the relative amount of leverage contained in its capital structure. As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.79% (11.05% - 10.26%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

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

A. As explained previously, I have utilized a six-month average dividend yield ("$D_1$ /$P_0$") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot."). The factor used to develop the modification that would account for the flotation costs adjustment is provided in Attachment PRM-10 and Appendix F. Therefore, a flotation costs adjustment must be applied to the DCF result (i.e., "k") that provides an additional increment to the rate of return on equity (i.e., "K").

**Q. What DCF cost rate have you calculated?**

A. The resulting DCF cost rate is:

| | $D_1/P_0$ | + | $g$ | + | $lev.$ | = | $k$ | $x$ | $flot.$ | = | $K$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Proxy Group | 4.01% | + | 6.25% | + | 0.79% | = | 11.05% | x | 1.02 | = | 11.27% |

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.22% (11.27% - 11.05%) to the rate of return on common equity for the Proxy Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant.

## RISK PREMIUM ANALYSIS

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

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix H. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. As with other models of the cost of equity, the Risk Premium approach has its limitations, including an accurate assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

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

A. In my opinion, a 6.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Attachment PRM-11. For the twelve months ended January 2008, the average monthly yield on Moody's A-rated index of public utility bonds was 6.08%. For the six and three-month periods ended January 2008, the yields were

6.11% and 6.05%, respectively. During the twelve-months ended January 2008, the range of the yields on A-rated public utility bonds was 5.85% to 6.30%.

**Q. What forecasts of interest rates have you considered in your analysis?**

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix G. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on February 1, 2008, and the yield spread of 1.50%. For comparative purposes, I also have shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

| | | Blue Chip Financial Forecasts | | | A-rated Public Utility | |
|---|---|---|---|---|---|---|
| | | Corporate | | 30-Year | | |
| Year | Quarter | Aaa-rated | Baa-rated | Treasury | Spread | Yield |
| 2008 | 1st | 5.2% | 6.3% | 4.2% | 1.50% | 5.70% |
| 2008 | 2nd | 5.1% | 6.2% | 4.1% | 1.50% | 5.60% |
| 2008 | 3rd | 5.2% | 6.3% | 4.2% | 1.50% | 5.70% |
| 2008 | 4th | 5.3% | 6.4% | 4.3% | 1.50% | 5.80% |
| 2009 | 1st | 5.5% | 6.5% | 4.5% | 1.50% | 6.00% |
| 2009 | 2nd | 5.6% | 6.6% | 4.6% | 1.50% | 6.10% |

**Q. Are there additional forecasts of interest rates that extend beyond those shown above?**

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2007 publication, the Blue Chip published forecasts of interest rates are reported to be:

| | Blue Chip Financial Forecasts | | | | |
|---|---|---|---|---|---|
| | Corporate | | 30-Year | A-rated Public Utility | |
| Averages | Aaa-rated | Baa-rated | Treasury | Spread | Yield |
| 2009-13 | 6.0% | 7.0% | 5.2% | 1.50% | 6.70% |
| 2014-18 | 6.1% | 7.0% | 5.3% | 1.50% | 6.80% |

Given these forecast interest rates, a 6.00% yield on A-rated public utility bonds represents a reasonable expectation.

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

A. Appendix H provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities, rather than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Proxy Group.

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

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Attachment PRM-12, the indicated risk premiums for the various time periods analyzed are 5.37% (1928-2006), 6.40% (1952-2006), 5.61% (1974-2006), and 5.83% (1979-2006). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals, and removes some of the more distant data from the analysis.

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

A. Yes. First, the terminal year of my analysis presented in Attachment PRM-12 represents the returns realized through 2006. Second, the selection of the initial year of each period was based upon the events that I described in Appendix H. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo.

Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

**Q. What conclusions have you drawn from these data?**

A. Using the summary values provided on page 2 of Attachment PRM-12, the 1928-2006 period provides the lowest indicated risk premium, while the 1952-2006 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.72% (5.61% + 5.83% = 11.44% ÷ 2) is shown from data covering the periods 1974-2006 and 1979-2006. Therefore, 5.72% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Proxy Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Proxy Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.25% represents a reasonable common equity risk premium in this case. This represents approximately 92%

(5.25% ÷ 5.72% = 0.92) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Proxy Group compared to the S&P Public Utilities.

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

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

| | *i* | + | *RP* | = | *k* | + | *flot.* | = | *K* |
|---|---|---|---|---|---|---|---|---|---|
| Proxy Group | 6.00% | + | 5.25% | = | 11.25% | + | 0.22% | = | 11.47% |

## CAPITAL ASSET PRICING MODEL

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

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

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

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

**Q. What betas have you considered in the CAPM?**

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Attachment PRM-13, the average beta is .84 for the Proxy Group.

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

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

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

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at its market values, the beta would become .63 for the Proxy Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of 1.01 for the Proxy Group associated with book value capital structure. The betas and their corresponding common equity ratios are:

| Market Values | | Book Values | |
|---|---|---|---|
| Beta | Common Equity Ratio | Beta | Common Equity Ratio |
| 0.84 | 65.68% | 1.01 | 52.33% |

The leveraged beta that I will employ in the CAPM cost of equity is 1.01 for the Proxy Group.

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

A. For reasons explained in Appendix G, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Attachment PRM-13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended January 2008, the average yield was 4.86%, as shown on page 3 of that schedule. For the six- and three-months ended January 2008, the yields on 20-year Treasury bonds were 4.69% and 4.49%, respectively. During the twelve-months ended January 2008, the range of the yields on 20-year Treasury bonds was 4.35% to 5.29%. As shown on page 4 of Attachment PRM-11, forecasts published by Blue Chip on February 1, 2008 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.1% to 4.6% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.2% from 2009 through 2013 and 5.3% for 2014 to 2018. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 4.50% risk-free rate of return for CAPM purposes.

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

A. As developed in Appendix I, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 10.10%). For the historically based market premium, I have used the arithmetic mean. The resulting market premium is 8.30% (6.5% + 10.10% = 16.60% ÷ 2), which represents the average market premium using historical and forecast data.

**Q. Are there adjustments to the CAPM results that are necessary to fully reflect the rate of return on common equity?**

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. There would be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, Proxy Group has an average market capitalization of its equity of $3,515 million, which would make them a mid-cap portfolio. The mid-cap market capitalization would indicate a size premium of 0.97%. Absent such an adjustment, the CAPM would understate the required return.

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

A. Using the 4.50% risk-free rate of return, the leverage adjusted beta of 1.01 for the Proxy Group, the 8.30% market premium, the size adjustments, and the flotation cost adjustment, the following result is indicated.

| | *Rf* | + | *ß* | x ( | *Rm-Rf* | ) + | *size* | = | *k* | + | *flot.* | = | *K* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Proxy Group | 4.50% | + | 1.01 | x ( | 8.30% | ) + | 0.97% | = | 13.85% | + | 0.22% | = | 14.07% |

## <u>COMPARABLE EARNINGS APPROACH</u>

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

A. The technical aspects of the Comparable Earnings approach are set forth in Appendix J. Because regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms.

The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

**Q. How have you implemented the Comparable Earnings approach?**

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix J for definitions) of comparability designed to reflect the risk of the Proxy Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Proxy Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Attachment PRM-14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

**Q. What data have you used in your Comparable Earnings analysis?**

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because, the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 14.3% using the median value as shown on page 2 of Attachment PRM-14. The forecast rates of return, as published by Value Line, are shown by the 13.5% median values also provided on page 2 of Attachment PRM-14.

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

A. The average of the historical and forecast median rates of return is:

| | *Historical* | *Forecast* | *Average* |
|---|---|---|---|
| Comparable Earnings Group | 14.30% | 13.50% | 13.90% |

## CONCLUSION ON COST OF EQUITY

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is 11.50% for the Company. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

**Q: Does this conclude your Prepared Direct Testimony?**

A: Yes.

**BEFORE**
**THE PUBLIC UTILTIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service. | )<br>)<br>)<br>) | Case No. 08-0072-GA-AIR |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges. | )<br>)<br>)<br>) | Case No. 08-0073-GA-ALT |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods. | )<br>)<br>) | Case No. 08-0074-GA-AAM |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Revise its Depreciation Accrual Rates. | )<br>)<br>) | Case No. 08-0075-GA-AAM |

**EXHIBIT TO ACCOMPANY**
**PREPARED DIRECT TESTIMONY OF**
**PAUL R. MOUL**
**ON BEHALF OF COLUMBIA GAS OF OHIO, INC.**

Columbia Gas of Ohio, Inc.
Index of Attachments

**NiSource Inc. and Subsidiaries**
Proposed Rate of Return
Actual at December 31, 2007

| Type of Capital | Ratios | Cost Rate | Weighted Cost Rate |
|---|---|---|---|
| Long-term Debt | 50.54% | 6.79% | 3.43% |
| Common Equity | 49.46% | 11.50% | 5.69% |
| Total | 100.00% | | 9.12% |

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its proposed rate of return:

| | |
|---|---|
| Pre-tax coverage of interest expense based upon a 35.0000% composite federal and state income tax rate ( 12.18% ÷ 3.43% ) | 3.55 x |
| Post-tax coverage of interest expense ( 9.12% ÷ 3.43% ) | 2.66 x |

Columbia Gas Of Ohio, Inc.
Capitalization and Financial Statistics
2002-2006, Inclusive

| | 2006 | 2005 | 2004 (Millions of Dollars) | 2003 | 2002 | |
|---|---|---|---|---|---|---|
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 1,036.7 | $ 853.5 | $ 777.5 | $ 758.6 | $ 741.2 | |
| Short-Term Debt | $ - | $ 105.5 | $ 125.9 | $ 194.6 | $ - | |
| Total Capital | $ 1,036.7 | $ 959.0 | $ 903.4 | $ 953.2 | $ 741.2 | |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Capital: | | | | | | |
| Long-Term Debt | 40.2% | 36.0% | 39.6% | 40.5% | 41.4% | 39.5% |
| Common Equity [1] | 59.8% | 64.0% | 60.4% | 59.5% | 58.6% | 60.5% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 40.2% | 43.1% | 48.0% | 52.6% | 41.4% | 45.1% |
| Common Equity [1] | 59.8% | 56.9% | 52.0% | 47.4% | 58.6% | 54.9% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity | 12.6% | 15.0% | 24.4% | 28.4% | 26.6% | 21.4% |
| Operating Ratio [2] | 92.7% | 91.5% | 86.5% | 84.1% | 84.0% | 87.8% |
| Coverage incl. AFUDC [3] | | | | | | |
| Pre-tax: All Interest Charges | 6.71 x | 4.96 x | 7.19 x | 8.97 x | 7.79 x | 7.12 x |
| Post-tax: All Interest Charges | 4.61 x | 3.55 x | 5.05 x | 6.17 x | 5.47 x | 4.97 x |
| Coverage excl. AFUDC [3] | | | | | | |
| Pre-tax: All Interest Charges | 6.67 x | 4.95 x | 7.17 x | 8.96 x | 7.78 x | 7.11 x |
| Post-tax: All Interest Charges | 4.57 x | 3.54 x | 5.03 x | 6.16 x | 5.46 x | 4.95 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 1.3% | 0.4% | 0.5% | 0.2% | 0.2% | 0.5% |
| Effective Income Tax Rate | 36.7% | 35.6% | 34.6% | 35.1% | 34.2% | 35.2% |
| Internal Cash Generation/Construction [4] | 72.4% | 156.0% | 82.6% | 51.6% | 113.9% | 95.3% |
| Gross Cash Flow/ Avg. Total Debt [5] | 13.4% | 33.0% | 32.7% | 36.9% | 45.5% | 32.3% |
| Gross Cash Flow Interest Coverage [6] | 3.52 x | 5.44 x | 6.42 x | 7.17 x | 6.65 x | 5.84 x |
| Common Dividend Coverage [7] | x | x | 1.53 x | 1.23 x | 1.79 x | 1.52 x |

See Page 2 for Notes.

Columbia Gas of Ohio, Inc.
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) Excluding the Transitional Funding Obligations that were issue for stranded generating assets, and whose debt service is covered through dedicated revenue collections.
(2) Excluding Parent Company Receivable and Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Utility COMPUSTAT

Proxy Group
Capitalization and Financial Statistics [1]
2002-2006, Inclusive

| | 2006 | 2005 | 2004 (Millions of Dollars) | 2003 | 2002 | Average |
|---|---|---|---|---|---|---|
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 4,397.9 | $ 4,097.4 | $ 3,999.0 | $ 3,673.9 | $ 3,542.1 | |
| Short-Term Debt | $ 227.8 | $ 243.4 | $ 172.6 | $ 236.4 | $ 214.0 | |
| Total Capital | $ 4,625.7 | $ 4,340.8 | $ 4,171.6 | $ 3,910.3 | $ 3,756.1 | |
| Market-Based Financial Ratios | | | | | | |
| Price-Earnings Multiple | 18 x | 13 x | 16 x | 16 x | 16 x | 16 x |
| Market/Book Ratio | 181.4% | 181.2% | 170.9% | 163.9% | 157.6% | 171.0% |
| Dividend Yield | 3.9% | 3.9% | 4.2% | 4.6% | 4.5% | 4.2% |
| *Dividend Payout Ratio* | 69.1% | 49.6% | 66.0% | 74.3% | 76.2% | 67.0% |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Capital: | | | | | | |
| Long-Term Debt | 47.1% | 46.9% | 48.7% | 48.5% | 51.3% | 48.5% |
| Preferred Stock | 1.1% | 1.1% | 1.2% | 1.1% | 1.3% | 1.2% |
| Common Equity [2] | 51.8% | 52.0% | 50.1% | 50.4% | 47.4% | 50.3% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 52.3% | 51.4% | 52.5% | 54.5% | 54.8% | 53.1% |
| Preferred Stock | 1.0% | 1.1% | 1.1% | 1.1% | 1.3% | 1.1% |
| Common Equity [2] | 46.7% | 47.6% | 46.4% | 44.4% | 43.9% | 45.8% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity [2] | 11.0% | 9.8% | 11.0% | 11.1% | 10.6% | 10.7% |
| Operating Ratio [3] | 89.7% | 90.1% | 88.3% | 87.3% | 86.4% | 88.4% |
| Coverage incl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.65 x | 3.87 x | 4.08 x | 3.85 x | 3.23 x | 3.74 x |
| Post-tax: All Interest Charges | 2.68 x | 2.79 x | 2.89 x | 2.74 x | 2.38 x | 2.70 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.64 x | 2.75 x | 2.85 x | 2.71 x | 2.34 x | 2.66 x |
| Coverage excl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.61 x | 3.85 x | 4.05 x | 3.83 x | 3.21 x | 3.71 x |
| Post-tax: All Interest Charges | 2.64 x | 2.77 x | 2.86 x | 2.72 x | 2.36 x | 2.67 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.61 x | 2.73 x | 2.82 x | 2.68 x | 2.33 x | 2.63 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 3.8% | 0.0% | 2.3% | 2.9% | 1.2% | 2.0% |
| Effective Income Tax Rate | 18.0% | 38.0% | 37.7% | 38.1% | 37.6% | 33.9% |
| Internal Cash Generation/Construction [5] | 73.5% | 68.9% | 99.4% | 122.8% | 82.0% | 89.3% |
| Gross Cash Flow/ Avg. Total Debt [6] | 18.4% | 17.4% | 21.7% | 24.0% | 19.9% | 20.3% |
| Gross Cash Flow Interest Coverage [7] | 3.92 x | 4.08 x | 4.81 x | 4.97 x | 3.79 x | 4.31 x |
| Common Dividend Coverage [8] | 2.92 x | 2.93 x | 3.92 x | 4.32 x | 3.80 x | 3.58 x |

See Page 2 for Notes.

Proxy Group
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Proxy Group includes companies that (i) are engaged in the distribution of natural gas distribution or gas distribution and the delivery of electricity, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) operate in the New England, Middle Atlantic , and South Atlantic regions of the U.S., (v) are not currently the target of a merger or acquisition, and (vi) in the case of the combination utilities, do not have a significant amount of electric generation that is unregulated.

| | | Corporate Credit Ratings | | Stock | S&P Stock | Value Line |
|---|---|---|---|---|---|---|
| Ticker | Company | Moody's | S&P | Traded | Ranking | Beta |
| ATG | AGL Resources, Inc. | A3 | A- | NYSE | A- | 0.85 |
| CHG | CH Energy Group | A2 | A | NYSE | A- | 0.90 |
| ED | Consolidated Edison | A1 | A | NYSE | B+ | 0.75 |
| NJR | New Jersey Resources Corp | Aa3 | A+ | NYSE | A | 0.85 |
| GAS | NICOR, Inc. | A1 | AA | NYSE | B | 0.80 |
| NU | Northeast Utilities | Baa1 | BBB | NYSE | B | 0.75 |
| NST | NSTAR | A1 | A+ | NYSE | A- | 0.95 |
| POM | Pepco Holdings | Baa2 | BBB | NYSE | B | 0.85 |
| SJI | South Jersey Industries, Inc. | Baa2 | BBB+ | NYSE | B+ | 0.85 |
| WGL | WGL Holdings, Inc. | A2 | AA- | NYSE | B+ | 0.85 |
| | Average | A2 | A | | B+ | 0.84 |

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2002-2006, Inclusive

| | 2006 | 2005 | 2004 (Millions of Dollars) | 2003 | 2002 | Average |
|---|---|---|---|---|---|---|
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 15,146.0 | $ 14,261.2 | $14,164.3 | $ 14,259.5 | $13,850.0 | |
| Short-Term Debt | $ 516.4 | $ 480.8 | $ 279.5 | $ 266.9 | $ 913.6 | |
| Total Capital | $ 15,662.4 | $ 14,742.0 | $14,443.8 | $ 14,526.4 | $14,763.6 | |
| Market-Based Financial Ratios | | | | | | |
| Price-Earnings Multiple | 18 x | 16 x | 15 x | 13 x | 14 x | 15 x |
| Market/Book Ratio | 206.6% | 201.8% | 182.4% | 150.6% | 152.2% | 178.7% |
| Dividend Yield | 3.5% | 3.5% | 3.8% | 4.2% | 5.0% | 4.0% |
| Dividend Payout Ratio | 56.3% | 57.2% | 70.3% | 58.8% | 72.8% | 63.1% |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Captial: | | | | | | |
| Long-Term Debt | 54.1% | 55.6% | 57.4% | 59.3% | 60.4% | 57.4% |
| Preferred Stock | 1.1% | 1.3% | 1.5% | 1.6% | 1.8% | 1.5% |
| Common Equity [2] | 44.7% | 43.2% | 41.0% | 39.1% | 37.8% | 41.2% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 56.1% | 57.7% | 59.0% | 60.7% | 63.1% | 59.3% |
| Preferred Stock | 1.1% | 1.2% | 1.5% | 1.6% | 1.7% | 1.4% |
| Common Equity [2] | 42.8% | 41.1% | 39.5% | 37.7% | 35.2% | 39.3% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity [2] | 12.3% | 11.4% | 11.5% | 10.0% | 8.1% | 10.7% |
| Operating Ratio [3] | 81.2% | 85.2% | 84.4% | 84.8% | 84.5% | 84.0% |
| Coverage incl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.42 x | 3.20 x | 3.02 x | 2.57 x | 2.41 x | 2.92 x |
| Post-tax: All Interest Charges | 2.64 x | 2.54 x | 2.42 x | 2.12 x | 1.99 x | 2.34 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.61 x | 2.50 x | 2.38 x | 2.07 x | 1.95 x | 2.30 x |
| Coverage excl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.38 x | 3.17 x | 2.99 x | 2.53 x | 2.37 x | 2.89 x |
| Post-tax: All Interest Charges | 2.60 x | 2.51 x | 2.39 x | 2.08 x | 1.95 x | 2.31 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.56 x | 2.47 x | 2.35 x | 2.03 x | 1.90 x | 2.26 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 2.4% | 0.9% | 3.0% | 1.7% | 2.6% | 2.1% |
| Effective Income Tax Rate | 32.4% | 31.3% | 26.2% | 40.3% | 29.0% | 31.8% |
| Internal Cash Generation/Construction [5] | 95.6% | 108.3% | 127.0% | 127.8% | 91.8% | 110.1% |
| Gross Cash Flow/ Avg. Total Debt [6] | 23.8% | 21.3% | 21.1% | 20.8% | 19.0% | 21.2% |
| Gross Cash Flow Interest Coverage [7] | 4.57 x | 4.42 x | 4.42 x | 4.42 x | 4.07 x | 4.38 x |
| Common Dividend Coverage [8] | 4.41 x | 4.41 x | 5.00 x | 5.27 x | 4.23 x | 4.66 x |

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

**Standard & Poor's Public Utilities**

Company Identities [1]

| | Ticker | Credit Rating [2] Moody's | S&P | Common Stock Traded | S&P Stock Ranking | Value Line Beta |
|---|---|---|---|---|---|---|
| Allegheny Energy | AYE | Baa3 | BB+ | NYSE | B- | 1.85 |
| Ameren Corporation | AEE | A2 | BBB+ | NYSE | A- | 0.75 |
| American Electric Power | AEP | Baa2 | BBB | NYSE | B | 1.20 |
| CMS Energy | CMS | Ba1 | BB | NYSE | C | 1.45 |
| CenterPoint Energy | CNP | Baa3 | BBB | NYSE | B | 0.65 |
| Consolidated Edison | ED | A1 | A | NYSE | B+ | 0.65 |
| Constellation Energy Group | CEG | A3 | BBB+ | NYSE | B | 0.95 |
| DTE Energy Co. | DTE | Baa1 | BBB | NYSE | B+ | 0.70 |
| Dominion Resources | D | Baa1 | BBB | NYSE | B+ | 0.95 |
| Duke Energy | DUK | Baa2 | BBB | NYSE | B+ | 1.20 |
| Edison Int'l | EIX | Baa1 | BBB+ | NYSE | B | 1.05 |
| Entergy Corp. | ETR | Baa2 | BBB | NYSE | B+ | 0.85 |
| Exelon Corp. | EXC | A3 | BBB+ | NYSE | B+ | 0.80 |
| FPL Group | FPL | A1 | A | NYSE | A- | 0.80 |
| FirstEnergy Corp. | FE | Baa2 | BBB | NYSE | B+ | 0.75 |
| Integrys Energy Group | TEG | A1 | A- | NYSE | B | 0.85 |
| Keyspan Energy | KSE | A3 | A | NYSE | B | 0.85 |
| NICOR Inc. | GAS | A1 | AA | NYSE | B | 1.15 |
| NiSource Inc. | NI | Baa2 | BBB | NYSE | B | 0.80 |
| PG&E Corp. | PCG | Baa1 | BBB | NYSE | B | 1.10 |
| PPL Corp. | PPL | Baa1 | A- | NYSE | B | 1.00 |
| Pinnacle West Capital | PNW | Baa2 | BBB- | NYSE | A- | 0.90 |
| Progress Energy, Inc. | PGN | Baa1 | BBB | NYSE | B+ | 0.80 |
| Public Serv. Enterprise Inc. | PEG | Baa1 | BBB | NYSE | B+ | 0.90 |
| Questar Corp. | STR | A2 | A- | NYSE | A- | 0.90 |
| Sempra Energy | SRE | A2 | A | NYSE | B | 1.00 |
| Southern Co. | SO | A2 | A | NYSE | A- | 0.65 |
| TECO Energy | TE | Baa2 | BBB- | NYSE | B- | 1.00 |
| TXU CORP | TXU | Baa3 | BBB- | NYSE | B | 1.05 |
| Xcel Energy Inc | XEL | A3 | BBB+ | NYSE | B | 0.80 |
| Average for S&P Utilities | | Baa1 | BBB+ | | B | 0.95 |

Note: [1] Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.
[2] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

**NiSource Inc. and Subsidiaries**
Capitalization and Related Capital Structure Ratios
Actual at December 31, 2007

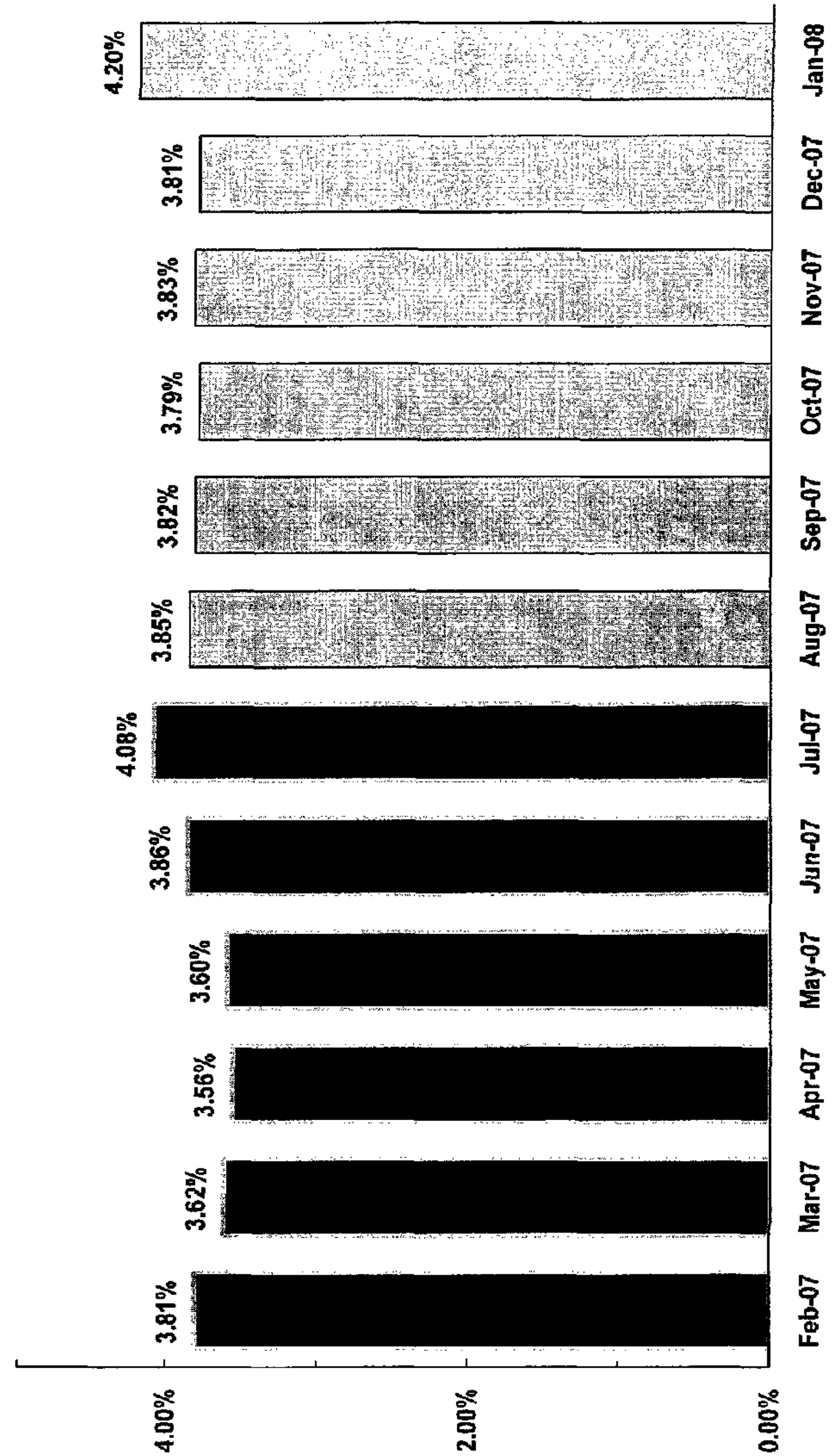
| Type of Capital | Amount Outstanding | Percent |
|---|---|---|
| Long-term Debt | $ 5,174,465,920 [1] | 50.54% |
| Common Equity | | |
| Common Stock | 2,752,895 | |
| Additional Paid in Capital | 4,011,050,341 | |
| Retained Earnings | 1,074,352,338 [2] | |
| Treasury Stock | (23,288,169) | |
| Total Common Equity | 5,064,867,405 | 49.46% |
| Total capital | $ 10,239,333,325 [3] | 100.00% |

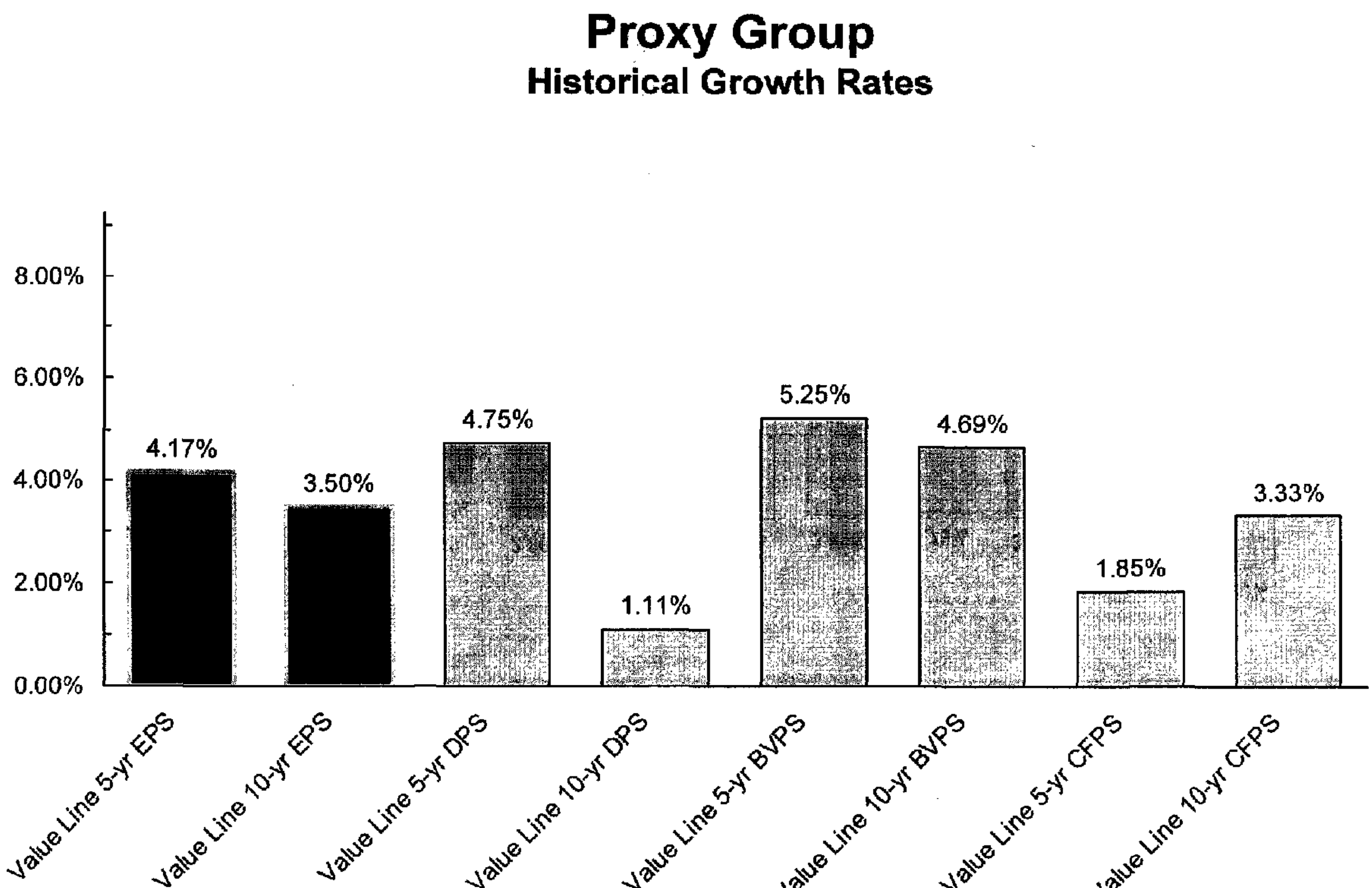
Notes:
[1] Long-term debt excludes debt of non-regulated subsidiaries and pollution control bonds of Northern Indiana Public Service Company.
[2] Common equity excludes Accumulated Other Comprehensive Income ("OCI).
[3] Total capital reflects an adjustment to equity that was booked subsequent to filing the D schedules.

**NiSource Inc. and Subsidiaries**
Embedded Cost Of Long-Term Debt
Actual at December 31, 2007

| Debt Issue Type and Coupon Rate | Coupon Rate | Date Issued (Day/Month/Year) (A) | Maturity Date (Day/Month/Year) (B) | Principal Amount (C) | Face Amount Outstanding (D) | Unamort. (Discount) or Premium (E) | Unamort. Debt Expense (F) | Unamort. Loss on Reacquired Debt (G) | Carrying Value (H=D+E-F-G) | Annual Interest Cost (I) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Medium Term Notes** | | | | | | | | | | |
| **Northern Indiana - Series E:** | | | | | | | | | | |
| Series E | 7.360% | 6-Jun-97 | 8-Jun-09 | $ 1,000,000 | $ 1,000,000 | | | | $ 1,000,000 | $ 73,500 |
| Series E | 7.590% | 10-Jun-97 | 12-Jun-17 | 22,500,000 | 22,500,000 | | | | 22,500,000 | 1,707,750 |
| Series E | 7.020% | 4-Aug-97 | 4-Aug-17 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 351,000 |
| Series E | 7.400% | 26-Aug-97 | 30-Aug-22 | 10,000,000 | 10,000,000 | | | | 10,000,000 | 740,000 |
| Series E | 7.690% | 6-Jun-97 | 6-Jun-27 | 20,000,000 | 20,000,000 | | | | 20,000,000 | 1,538,000 |
| Series E | 7.690% | 6-Jun-97 | 27-Jun-27 | 33,000,000 | 33,000,000 | | | | 33,000,000 | 2,537,700 |
| Series E | 7.160% | 4-Aug-97 | 4-Aug-27 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 358,000 |
| | | | | | | $ (501,951) | | | (501,951) | 49,456 |
| Northern Indiana - Series C: | | | | | | | | | | |
| Series C | 6.830% | 6-Jul-93 | 8-Jul-08 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 341,500 |
| Series C | 6.830% | 6-Jul-93 | 8-Jul-08 | 4,000,000 | 4,000,000 | | | | 4,000,000 | 273,200 |
| Series C | 6.830% | 6-Jul-93 | 8-Jul-08 | 3,000,000 | 3,000,000 | | | | 3,000,000 | 204,900 |
| Series C | 6.820% | 9-Jul-93 | 9-Jul-08 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 136,400 |
| Series C | 6.790% | 20-Jul-93 | 21-Jul-08 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 135,800 |
| Series C | 6.810% | 20-Jul-93 | 21-Jul-08 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 136,200 |
| Series C | 6.730% | 26-Jul-93 | 28-Jul-08 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 336,500 |
| Series C | 6.750% | 26-Jul-93 | 28-Jul-08 | 1,000,000 | 1,000,000 | | | | 1,000,000 | 67,500 |
| Series C | 7.320% | 6-Jul-93 | 6-Jul-11 | 8,000,000 | 8,000,000 | | | | 8,000,000 | 585,600 |
| Series C | 7.290% | 16-Jul-93 | 18-Jul-11 | 8,700,000 | 8,700,000 | | | | 8,700,000 | 634,230 |
| Series C | 7.270% | 20-Jul-93 | 20-Jul-11 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 145,400 |
| Series C | 7.350% | 8-Jul-93 | 8-Jul-13 | 7,500,000 | 7,500,000 | | | | 7,500,000 | 551,250 |
| Series C | 7.350% | 8-Jul-93 | 8-Jul-13 | 7,500,000 | 7,500,000 | | | | 7,500,000 | 551,250 |
| Series C | 7.210% | 22-Jul-93 | 22-Jul-13 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 360,500 |
| Series C | 7.160% | 17-Aug-93 | 19-Aug-13 | 30,000,000 | 30,000,000 | | | | 30,000,000 | 2,148,000 |
| | | | | | | (3,149,126) | | | (3,149,126) | 512,856 |
| Bay State | | | | | | | | | | |
| Notes | 9.200% | 5-Jun-91 | 6-Jun-11 | 8,500,000 | 8,500,000 | (245,912) | | | 8,254,088 | 820,584 |
| Notes | 6.490% | 15-Dec-95 | 15-Dec-25 | 10,000,000 | 10,000,000 | (1,535,986) | | | 8,464,014 | 764,824 |
| Notes | 6.260% | 11-Feb-98 | 15-Feb-28 | 30,000,000 | 30,000,000 | (3,854,554) | | | 26,145,446 | 2,069,928 |
| Northern Utilites | | | | | | | | | | |
| Notes | 6.930% | 29-Sep-95 | 1-Sep-08 | 833,000 | 833,000 | | | | 833,000 | 57,727 |
| Notes | 6.930% | 29-Sep-95 | 1-Sep-10 | 1,667,000 | 1,667,000 | (245,000) | | | 1,422,000 | 175,523 |
| Capital Markets | | | | | | | | | | |
| | 7.790% | 16-Apr-97 | 18-Apr-08 | 5,000,000 | 5,000,000 | | | | 5,000,000 | 389,500 |
| | 7.720% | 16-Apr-97 | 17-Apr-09 | 10,000,000 | 10,000,000 | | | | 10,000,000 | 772,000 |
| | 7.850% | 27-Mar-97 | 27-Mar-17 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 157,000 |
| | 7.860% | 27-Mar-97 | 27-Mar-17 | 30,000,000 | 30,000,000 | | | | 30,000,000 | 2,358,000 |
| | 7.820% | 31-Mar-97 | 3-Apr-17 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 156,400 |
| | 7.820% | 31-Mar-97 | 3-Apr-17 | 10,000,000 | 10,000,000 | | | | 10,000,000 | 782,000 |
| | 7.820% | 31-Mar-97 | 3-Apr-17 | 10,000,000 | 10,000,000 | | | | 10,000,000 | 782,000 |
| | 7.930% | 1-Apr-97 | 3-Apr-17 | 2,000,000 | 2,000,000 | | | | 2,000,000 | 158,600 |
| | 7.940% | 1-Apr-97 | 3-Apr-17 | 1,000,000 | 1,000,000 | | | | 1,000,000 | 79,400 |
| | 7.990% | 31-Mar-97 | 1-Apr-22 | 6,000,000 | 6,000,000 | | | | 6,000,000 | 479,400 |
| | 7.990% | 31-Mar-97 | 1-Apr-22 | 8,000,000 | 8,000,000 | | | | 8,000,000 | 639,200 |
| | 7.990% | 31-Mar-97 | 1-Apr-22 | 6,000,000 | 6,000,000 | | | | 6,000,000 | 479,400 |
| | 7.990% | 5-May-97 | 5-May-27 | 29,000,000 | 29,000,000 | | | | 29,000,000 | 2,317,100 |
| | | | | | | (1,523,669) | | | (1,523,669) | 107,570 |
| **Senior Notes:** | | | | | | | | | | |
| **Capital Markets** | 6.780% | 1-Dec-97 | 1-Dec-27 | 3,000,000 | 3,000,000 | | | | 3,000,000 | 203,400 |
| NiSource Finance Corp. | | | | | | | | | | |
| Notes - Floating | 5.585% | 23-Nov-04 | 23-Nov-09 | 450,000,000 | 450,000,000 | (990,000) | | | 449,010,000 | 25,672,500 |
| Notes | 7.875% | 15-Nov-00 | 15-Nov-10 | 1,000,000,000 | 1,000,000,000 | (3,224,280) | | | 996,775,720 | 79,886,000 |
| Notes | 5.210% | 28-Nov-05 | 28-Nov-12 | 315,000,000 | 315,000,000 | (1,091,325) | | | 313,908,675 | 16,624,876 |
| Notes | 5.400% | 15-Jul-03 | 15-Jul-14 | 500,000,000 | 500,000,000 | (1,737,270) | | | 498,262,730 | 27,267,000 |
| Notes | 5.380% | 28-Nov-05 | 28-Nov-16 | 230,000,000 | 230,000,000 | (900,833) | | | 229,099,167 | 12,443,000 |
| Notes | 5.410% | 28-Nov-05 | 28-Nov-16 | 90,000,000 | 90,000,000 | (361,364) | | | 89,638,636 | 4,910,000 |
| Notes | 5.250% | 18-Sep-05 | 15-Sep-17 | 450,000,000 | 450,000,000 | (14,571,521) | $ 2,446,875 | | 432,981,604 | 25,188,100 |
| Notes | 5.450% | 16-Sep-05 | 15-Sep-20 | 550,000,000 | 550,000,000 | (18,142,936) | 3,483,333 | | 528,373,731 | 31,897,900 |
| Notes | 5.890% | 28-Nov-05 | 28-Nov-25 | 265,000,000 | 265,000,000 | | 1,181,458 | | 263,818,542 | 15,674,750 |
| Notes | 6.400% | 28-Aug-07 | 15-Mar-18 | 800,000,000 | 800,000,000 | (735,775) | 5,034,247 | | 794,229,979 | 51,765,227 |
| Hedging Fees | | | | | | | 668,467 | | (668,467) | 232,524 |
| Senior Unsecured Notes | 6.150% | 19-Feb-03 | 1-Mar-13 | 345,000,000 | 345,000,000 | | | | 345,000,000 | 21,217,500 |
| **Total Long-Term Debt** | | | | 5,359,200,000 | 5,359,200,000 | (52,751,701) | 12,814,379 | - | 5,293,633,920 | 340,956,226 |
| **Fixed to Variable Rate Swap Activity** | | | | | | | | | | |
| Receive Fixed 7.875% payments | | | | (660,000,000) | (660,000,000) | - | - | - | (660,000,000) | (51,975,000) |
| Pay Variable 6M LIBOR = 4.74%+3.08% | | | | 660,000,000 | 660,000,000 | - | - | - | 660,000,000 | 51,612,000 |
| Receive Fixed 5.4% payments | | | | (500,000,000) | (500,000,000) | - | - | - | (500,000,000) | (27,000,000) |
| Pay Variable 6M LIBOR = 5.39%+0.78% | | | | 500,000,000 | 500,000,000 | - | - | - | 500,000,000 | 30,850,000 |
| **Unamortized loss on reacquired CEG debt** | | | | - | - | - | - | $ 89,335,000 | (89,335,000) | 9,008,000 |
| **Current Maturities** | | | | (29,633,000) | (29,633,000) | - | - | - | (29,633,000) | (2,079,227) |
| **Total** | | | | $ 5,329,567,000 | $ 5,329,567,000 | $ (52,751,701) | $ 12,814,379 | $ 89,335,000 | $ 5,174,465,920 | $ 351,371,999 |
| **Embedded Cost of Long-Term Debt (I / H)** | | | | | | | | | | 6.7905% |

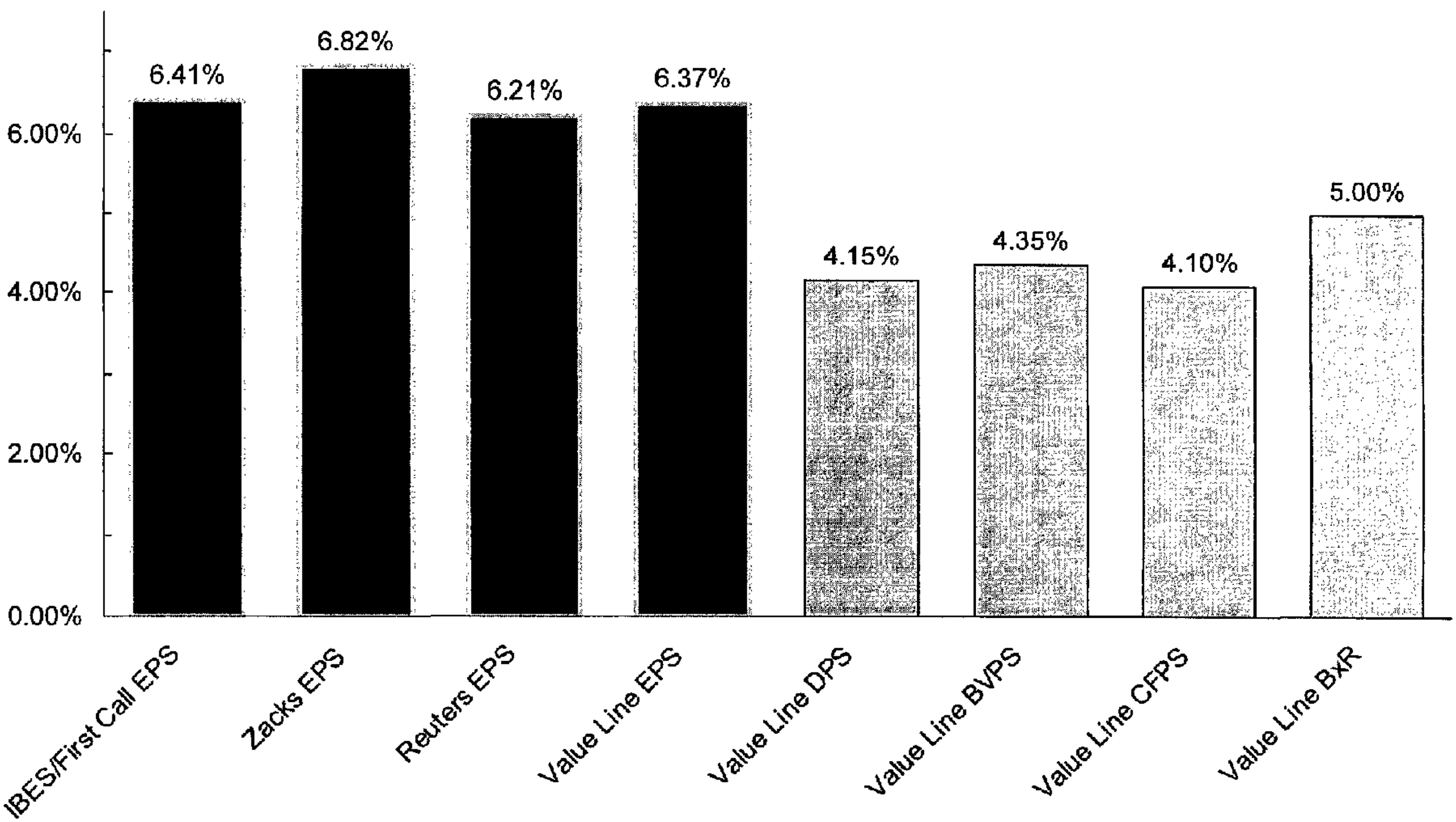
## Proxy Group
### Monthly Dividend Yield






Earnings per Share=EPS
Book Values per Share=BVPS
Dividends per Share=DPS
Cash Flow per Share=CFPS
Percent Retained to C[illegible] Equity=BxR

# Proxy Group
## Five-Year Projected Growth Rates




Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

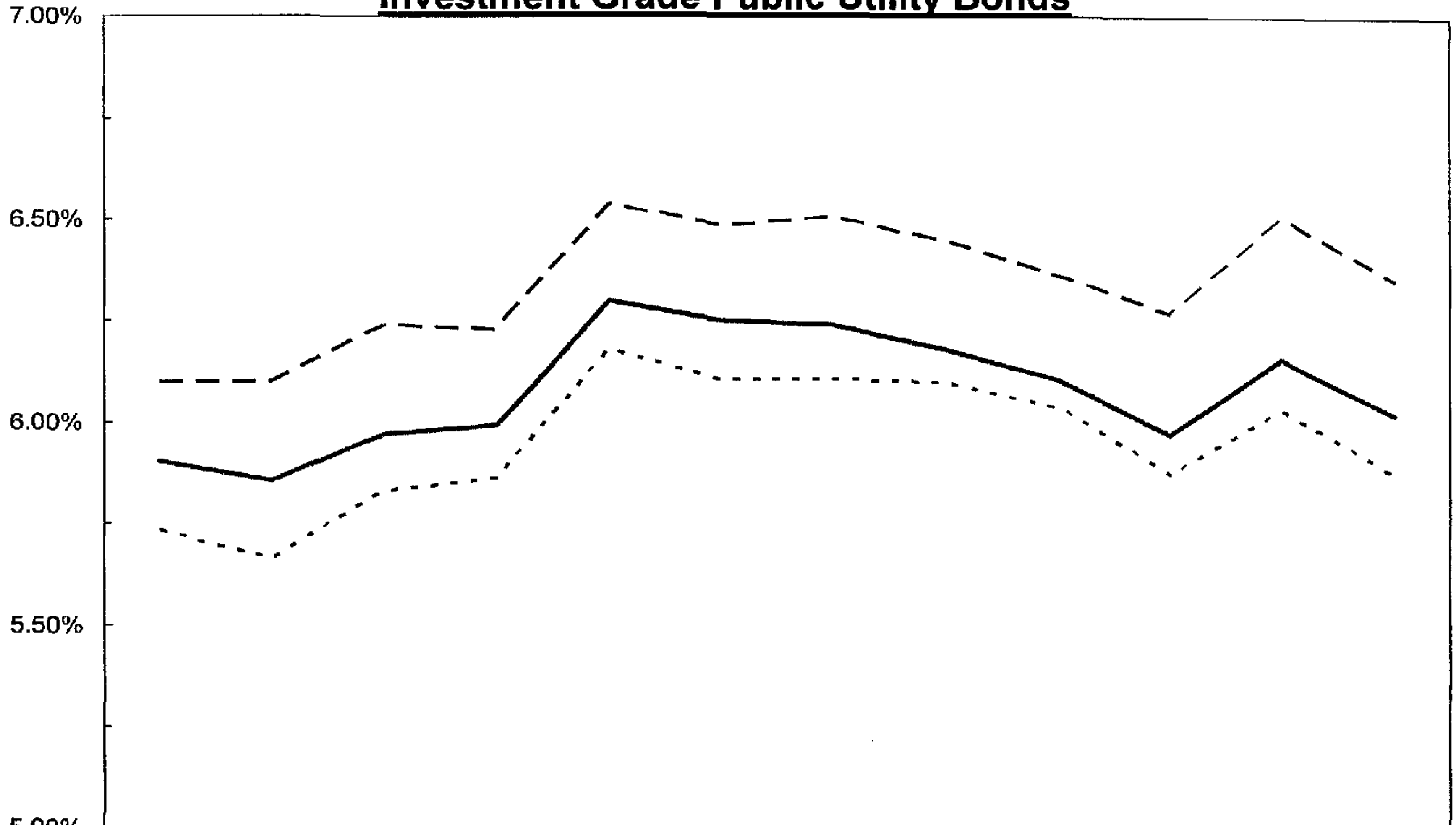
**Natural Gas Industry**
Analysis of Public Offerings of Common Stock
Years 2002-2006

| | UTILICORP | MDU Resources | AGL RESOURCES | SOUTHERN UNION CO. | ATMOS ENERGY | VECTREN CORP. | SEMPRA ENERGY | PIEDMONT NATURAL | UGI CORP. |
|---|---|---|---|---|---|---|---|---|---|
| Date of Offering | 1/25/2002 | 11/29/2002 | 2/11/2003 | 6/5/2003 | 6/16/2003 | 8/7/2003 | 10/8/2003 | 1/20/2004 | 3/18/2004 |
| No. of shares offered (000) | 11,000 | 2,100 | 5,600 | 9,500 | 4,000 | 6,500 | 15,000 | 4,250 | 7,500 |
| Dollar amt. of offering ($000) | $ 253,000 | $ 50,400 | $ 123,200 | $ 152,000 | $ 101,240 | $ 148,265 | $ 420,000 | $ 180,625 | $ 240,750 |
| Price to public | $ 23.000 | $ 24.200 | $ 22.000 | $ 16.000 | $ 25.310 | $ 22.810 | $ 28.000 | $ 42.500 | $ 32.100 |
| Underwriter's discounts and commission | $ 0.748 | $ 0.720 | $ 0.770 | $ 0.560 | $ 1.013 | $ 0.798 | $ 0.840 | $ 1.490 | $ 1.404 |
| Gross Proceeds | $ 22.252 | $ 23.480 | $ 21.230 | $ 15.440 | $ 24.297 | $ 22.012 | $ 27.160 | $ 41.010 | $ 30.696 |
| Estimated company issuance expenses | NA | $ 0.092 | $ 0.045 | $ 0.089 | $ 0.095 | $ 0.046 | $ 0.033 | NA | $ 0.020 |
| Net proceeds to company per share | $ 22.252 | $ 23.388 | $ 21.185 | $ 15.351 | $ 24.202 | $ 21.966 | $ 27.127 | $ 41.010 | $ 30.676 |
| Underwriter's discount as a percent of offering price | 3.3% | 3.0% | 3.5% | 3.5% | 4.0% | 3.5% | 3.0% | 3.5% | 4.4% |
| Issuance expense as a percent of offering price | NA | 0.4% | 0.2% | 0.6% | 0.4% | 0.2% | 0.1% | NA | 0.1% |
| Total Issuance and selling expense as as a percent of offering price | 3.3% | 3.4% | 3.7% | 4.1% | 4.4% | 3.7% | 3.1% | 3.5% | 4.5% |

| | NORTHWEST NATURAL | LACLEDE GROUP | SOUTHERN UNION CO. | AQUILA | ATMOS ENERGY | AGL RESOURCES | SOUTHERN UNION CO. | SEMCO Energy | Chesapeake Utilities | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| Date of Offering | 3/30/2004 | 5/6/2004 | 7/26/2004 | 8/18/2004 | 10/21/2004 | 11/19/2004 | 2/7/2005 | 8/9/2005 | 11/15/2006 | |
| No. of shares offered (000) | 1,200 | 1,500 | 11,000 | 40,000 | 14,000 | 9,600 | 14,913 | 4,300 | 600.3 | |
| Dollar amt. of offering ($000) | $ 37,200 | $ 40,200 | $ 206,250 | $ 102,000 | $ 346,500 | $ 297,696 | $ 342,999 | $ 27,176 | $ 18,069 | |
| Price to public | $ 31.000 | $ 26.800 | $ 18.750 | $ 2.550 | $ 24.750 | $ 31.010 | $ 23.000 | $ 6.320 | $ 30.100 | |
| Underwriter's discounts and commission | $ 1.010 | $ 0.871 | $ 0.656 | $ 0.099 | $ 0.990 | $ 0.930 | $ 0.700 | $ 0.253 | $ 1.125 | |
| Gross Proceeds | $ 29.990 | $ 25.929 | $ 18.094 | $ 2.461 | $ 23.760 | $ 30.080 | $ 22.300 | $ 6.067 | $ 28.975 | |
| Estimated company issuance expenses | $ 0.146 | $ 0.067 | $ 0.091 | NA | NA | $ 0.042 | $ 0.067 | $ 0.070 | $ 0.375 | |
| Net proceeds to company per share | $ 29.844 | $ 25.862 | $ 18.003 | $ 2.451 | $ 23.760 | $ 30.038 | $ 22.233 | $ 5.997 | $ 28.600 | |
| Underwriter's discount as a percent of offering price | 3.3% | 3.3% | 3.5% | 3.9% | 4.0% | 3.0% | 3.0% | 4.0% | 3.7% | 3.5% |
| Issuance expense as a percent of offering price | 0.5% | 0.3% | 0.5% | NA | NA | 0.1% | 0.3% | 1.1% | 1.2% | 0.4% |
| Total Issuance and selling expense as as a percent of offering price | 3.8% | 3.6% | 4.0% | 3.9% | 4.0% | 3.1% | 3.3% | 5.1% | 4.9% | 3.9% |

Source of Information: Public Utility Financial Tracker

# Interest Rates for Investment Grade Public Utility Bonds



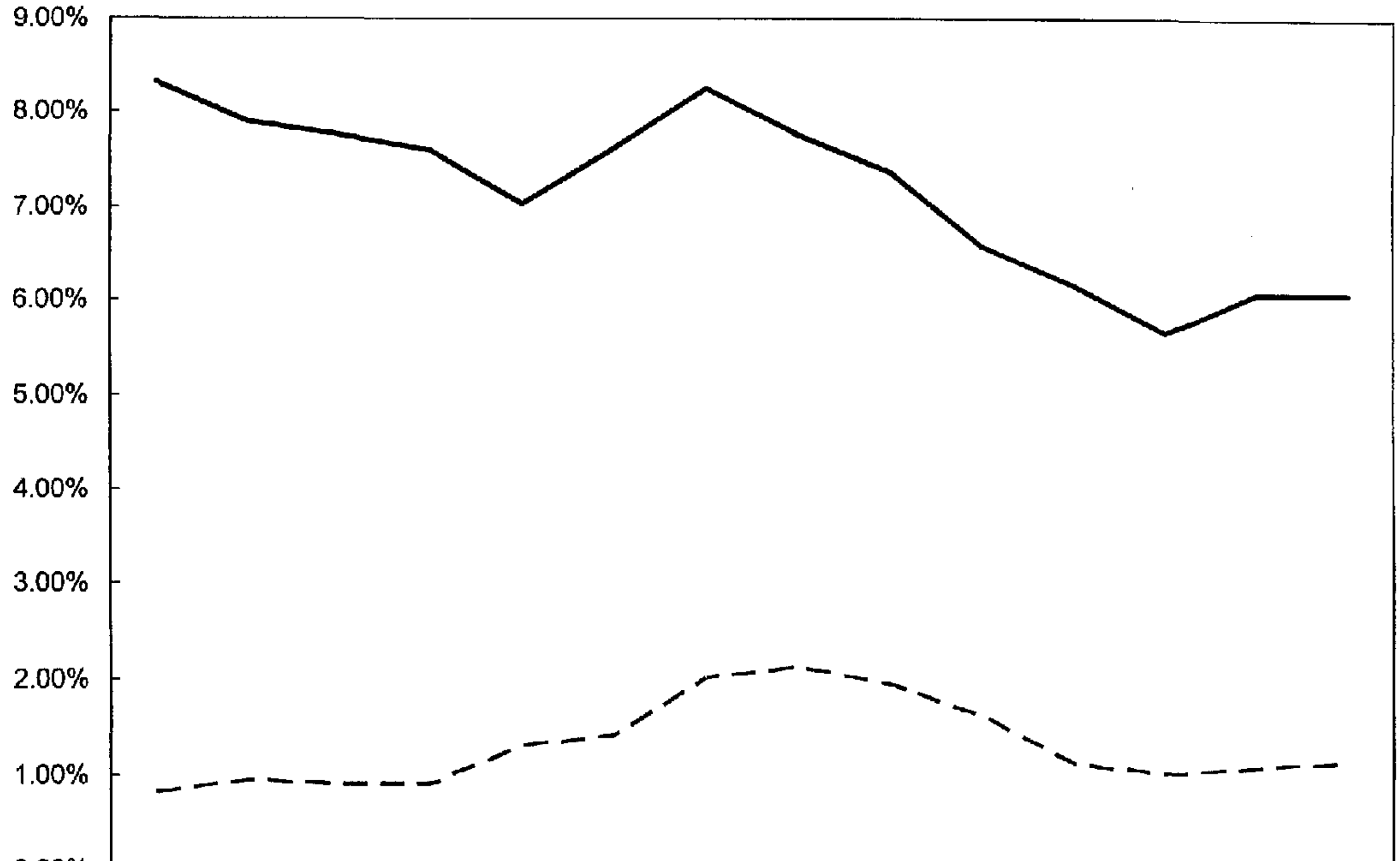

| | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 | Nov-07 | Dec-07 | Jan-08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Aa | 5.73% | 5.66% | 5.83% | 5.86% | 6.18% | 6.11% | 6.11% | 6.10% | 6.04% | 5.87% | 6.03% | 5.87% |
| A | 5.90% | 5.85% | 5.97% | 5.99% | 6.30% | 6.25% | 6.24% | 6.18% | 6.11% | 5.97% | 6.16% | 6.02% |
| Baa | 6.10% | 6.10% | 6.24% | 6.23% | 6.54% | 6.49% | 6.51% | 6.45% | 6.36% | 6.27% | 6.51% | 6.35% |

## Interest Rates for Investment Grade Public Utility Bonds
## Yearly for 2001-2006
## and the Twelve Months Ended January 2008

| Years | Aa Rated | A Rated | Baa Rated | Average |
|---|---|---|---|---|
| 2002 | 7.19% | 7.37% | 8.02% | 7.53% |
| 2003 | 6.40% | 6.58% | 6.84% | 6.61% |
| 2004 | 6.04% | 6.16% | 6.40% | 6.20% |
| 2005 | 5.44% | 5.65% | 5.93% | 5.67% |
| 2006 | 5.84% | 6.07% | 6.32% | 6.08% |
| **Five-Year Average** | 6.18% | 6.37% | 6.70% | 6.42% |
| 2007 | 5.94% | 6.07% | 6.33% | 6.11% |
| **Months** | | | | |
| Feb-07 | 5.73% | 5.90% | 6.10% | 5.91% |
| Mar-07 | 5.66% | 5.85% | 6.10% | 5.87% |
| Apr-07 | 5.83% | 5.97% | 6.24% | 6.01% |
| May-07 | 5.86% | 5.99% | 6.23% | 6.03% |
| Jun-07 | 6.18% | 6.30% | 6.54% | 6.34% |
| Jul-07 | 6.11% | 6.25% | 6.49% | 6.28% |
| Aug-07 | 6.11% | 6.24% | 6.51% | 6.28% |
| Sep-07 | 6.10% | 6.18% | 6.45% | 6.24% |
| Oct-07 | 6.04% | 6.11% | 6.36% | 6.17% |
| Nov-07 | 5.87% | 5.97% | 6.27% | 6.04% |
| Dec-07 | 6.03% | 6.16% | 6.51% | 6.23% |
| Jan-08 | 5.87% | 6.02% | 6.35% | 6.08% |
| **Twelve-Month Average** | 5.95% | 6.08% | 6.35% | 6.12% |
| **Six-Month Average** | 6.00% | 6.11% | 6.41% | 6.17% |
| **Three-Month Average** | 5.92% | 6.05% | 6.38% | 6.12% |

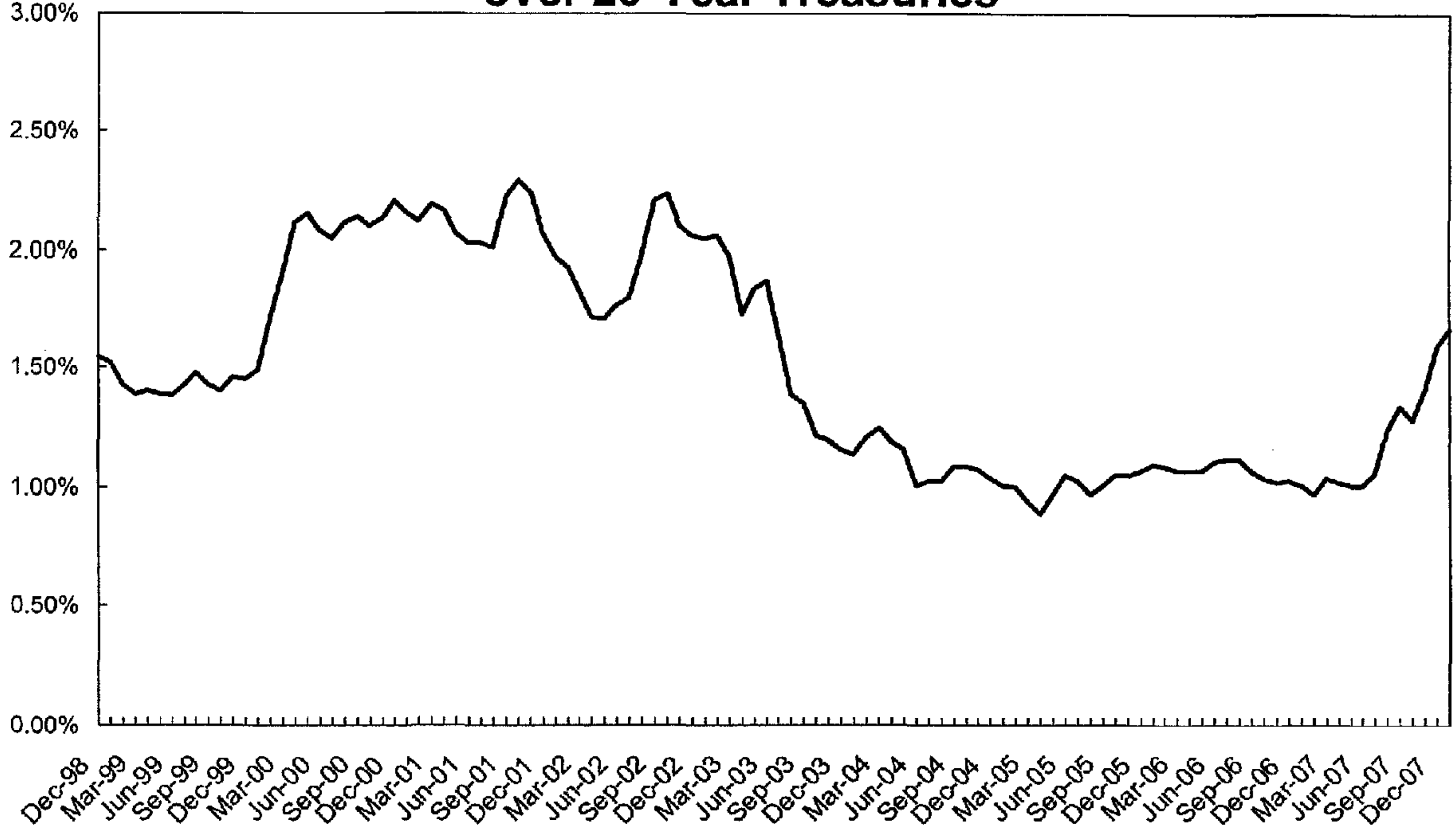
Source: Mergent Bond Record

# Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries




| | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-rated Public Utility | 8.31% | 7.89% | 7.75% | 7.60% | 7.04% | 7.62% | 8.24% | 7.76% | 7.37% | 6.58% | 6.16% | 5.65% | 6.07% | 6.07% |
| Spread vs. 20-year | 0.82% | 0.94% | 0.92% | 0.91% | 1.32% | 1.42% | 2.01% | 2.13% | 1.94% | 1.62% | 1.12% | 1.01% | 1.08% | 1.16% |

# Interest Rate Spreads
# A-rated Public Utility Bonds
# over 20-Year Treasuries



A rated Public Utility Bonds
over 20-Year Treasuries

| Year | A-rated Public Utility | 20-Year Treasuries Yield | Spread |
|---|---|---|---|
| Dec-98 | 6.91% | 5.36% | 1.55% |
| Jan-99 | 6.97% | 5.45% | 1.52% |
| Feb-99 | 7.09% | 5.66% | 1.43% |
| Mar-99 | 7.26% | 5.87% | 1.39% |
| Apr-99 | 7.22% | 5.82% | 1.40% |
| May-99 | 7.47% | 6.08% | 1.39% |
| Jun-99 | 7.74% | 6.36% | 1.38% |
| Jul-99 | 7.71% | 6.28% | 1.43% |
| Aug-99 | 7.91% | 6.43% | 1.48% |
| Sep-99 | 7.93% | 6.50% | 1.43% |
| Oct-99 | 8.06% | 6.66% | 1.40% |
| Nov-99 | 7.94% | 6.48% | 1.46% |
| Dec-99 | 8.14% | 6.69% | 1.45% |
| Jan-00 | 8.35% | 6.86% | 1.49% |
| Feb-00 | 8.25% | 6.54% | 1.71% |
| Mar-00 | 8.28% | 6.38% | 1.90% |
| Apr-00 | 8.29% | 6.18% | 2.11% |
| May-00 | 8.70% | 6.55% | 2.15% |
| Jun-00 | 8.36% | 6.28% | 2.08% |
| Jul-00 | 8.25% | 6.20% | 2.05% |
| Aug-00 | 8.13% | 6.02% | 2.11% |
| Sep-00 | 8.23% | 6.09% | 2.14% |
| Oct-00 | 8.14% | 6.04% | 2.10% |
| Nov-00 | 8.11% | 5.98% | 2.13% |
| Dec-00 | 7.84% | 5.64% | 2.20% |
| Jan-01 | 7.80% | 5.65% | 2.15% |
| Feb-01 | 7.74% | 5.62% | 2.12% |
| Mar-01 | 7.68% | 5.49% | 2.19% |
| Apr-01 | 7.94% | 5.78% | 2.16% |
| May-01 | 7.99% | 5.92% | 2.07% |
| Jun-01 | 7.85% | 5.82% | 2.03% |
| Jul-01 | 7.78% | 5.75% | 2.03% |
| Aug-01 | 7.59% | 5.58% | 2.01% |
| Sep-01 | 7.75% | 5.53% | 2.22% |
| Oct-01 | 7.63% | 5.34% | 2.29% |
| Nov-01 | 7.57% | 5.33% | 2.24% |
| Dec-01 | 7.83% | 5.76% | 2.07% |
| Jan-02 | 7.66% | 5.69% | 1.97% |
| Feb-02 | 7.54% | 5.61% | 1.93% |
| Mar-02 | 7.76% | 5.93% | 1.83% |
| Apr-02 | 7.57% | 5.85% | 1.72% |
| May-02 | 7.52% | 5.81% | 1.71% |
| Jun-02 | 7.42% | 5.65% | 1.77% |
| Jul-02 | 7.31% | 5.51% | 1.80% |
| Aug-02 | 7.17% | 5.19% | 1.98% |
| Sep-02 | 7.08% | 4.87% | 2.21% |
| Oct-02 | 7.23% | 5.00% | 2.23% |
| Nov-02 | 7.14% | 5.04% | 2.10% |
| Dec-02 | 7.07% | 5.01% | 2.06% |
| Jan-03 | 7.07% | 5.02% | 2.05% |
| Feb-03 | 6.93% | 4.87% | 2.06% |
| Mar-03 | 6.79% | 4.82% | 1.97% |
| Apr-03 | 6.64% | 4.91% | 1.73% |
| May-03 | 6.36% | 4.52% | 1.84% |
| Jun-03 | 6.21% | 4.34% | 1.87% |
| Jul-03 | 6.57% | 4.92% | 1.65% |
| Aug-03 | 6.78% | 5.39% | 1.39% |
| Sep-03 | 6.56% | 5.21% | 1.35% |
| Oct-03 | 6.43% | 5.21% | 1.22% |
| Nov-03 | 6.37% | 5.17% | 1.20% |
| Dec-03 | 6.27% | 5.11% | 1.16% |
| Jan-04 | 6.15% | 5.01% | 1.14% |
| Feb-04 | 6.15% | 4.94% | 1.21% |
| Mar-04 | 5.97% | 4.72% | 1.25% |
| Apr-04 | 6.35% | 5.16% | 1.19% |
| May-04 | 6.62% | 5.46% | 1.16% |
| Jun-04 | 6.46% | 5.45% | 1.01% |
| Jul-04 | 6.27% | 5.24% | 1.03% |
| Aug-04 | 6.14% | 5.07% | 1.07% |
| Sep-04 | 5.98% | 4.89% | 1.09% |
| Oct-04 | 5.94% | 4.85% | 1.09% |
| Nov-04 | 5.97% | 4.89% | 1.08% |
| Dec-04 | 5.92% | 4.88% | 1.04% |
| Jan-05 | 5.78% | 4.77% | 1.01% |
| Feb-05 | 5.61% | 4.61% | 1.00% |
| Mar-05 | 5.83% | 4.89% | 0.94% |
| Apr-05 | 5.64% | 4.75% | 0.89% |
| May-05 | 5.53% | 4.56% | 0.97% |
| Jun-05 | 5.40% | 4.35% | 1.05% |
| Jul-05 | 5.51% | 4.48% | 1.03% |
| Aug-05 | 5.50% | 4.53% | 0.97% |
| Sep-05 | 5.52% | 4.51% | 1.01% |
| Oct-05 | 5.79% | 4.74% | 1.05% |
| Nov-05 | 5.88% | 4.83% | 1.05% |
| Dec-05 | 5.80% | 4.73% | 1.07% |
| Jan-06 | 5.75% | 4.65% | 1.10% |
| Feb-06 | 5.82% | 4.73% | 1.09% |
| Mar-06 | 5.98% | 4.91% | 1.07% |
| Apr-06 | 6.29% | 5.22% | 1.07% |
| May-06 | 6.42% | 5.35% | 1.07% |
| Jun-06 | 6.40% | 5.29% | 1.11% |
| Jul-06 | 6.37% | 5.25% | 1.12% |
| Aug-06 | 6.20% | 5.08% | 1.12% |
| Sep-06 | 6.00% | 4.93% | 1.07% |
| Oct-06 | 5.98% | 4.94% | 1.04% |
| Nov-06 | 5.80% | 4.78% | 1.02% |
| Dec-06 | 5.81% | 4.78% | 1.03% |
| Jan-07 | 5.96% | 4.95% | 1.01% |
| Feb-07 | 5.90% | 4.93% | 0.97% |
| Mar-07 | 5.85% | 4.81% | 1.04% |
| Apr-07 | 5.97% | 4.95% | 1.02% |
| May-07 | 5.99% | 4.98% | 1.01% |
| Jun-07 | 6.30% | 5.29% | 1.01% |
| Jul-07 | 6.25% | 5.19% | 1.06% |
| Aug-07 | 6.24% | 5.00% | 1.24% |
| Sep-07 | 6.18% | 4.84% | 1.34% |
| Oct-07 | 6.11% | 4.83% | 1.28% |
| Nov-07 | 5.97% | 4.56% | 1.41% |
| Dec-07 | 6.16% | 4.57% | 1.59% |
| Jan-08 | 6.02% | 4.35% | 1.67% |

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2006

| Year | S & P Composite Index | S & P Public Utility Index | Long Term Corporate Bonds | Public Utility Bonds |
|---|---|---|---|---|
| 1928 | 43.61% | 57.47% | 2.84% | 3.08% |
| 1929 | -8.42% | 11.02% | 3.27% | 2.34% |
| 1930 | -24.90% | -21.96% | 7.98% | 4.74% |
| 1931 | -43.34% | -35.90% | -1.85% | -11.11% |
| 1932 | -8.19% | -0.54% | 10.82% | 7.25% |
| 1933 | 53.99% | -21.87% | 10.38% | -3.82% |
| 1934 | -1.44% | -20.41% | 13.84% | 22.61% |
| 1935 | 47.67% | 76.63% | 9.61% | 16.03% |
| 1936 | 33.92% | 20.69% | 6.74% | 8.30% |
| 1937 | -35.03% | -37.04% | 2.75% | -4.05% |
| 1938 | 31.12% | 22.45% | 6.13% | 8.11% |
| 1939 | -0.41% | 11.26% | 3.97% | 6.76% |
| 1940 | -9.78% | -17.15% | 3.39% | 4.45% |
| 1941 | -11.59% | -31.57% | 2.73% | 2.15% |
| 1942 | 20.34% | 15.39% | 2.60% | 3.81% |
| 1943 | 25.90% | 46.07% | 2.83% | 7.04% |
| 1944 | 19.75% | 18.03% | 4.73% | 3.29% |
| 1945 | 36.44% | 53.33% | 4.08% | 5.92% |
| 1946 | -8.07% | 1.26% | 1.72% | 2.98% |
| 1947 | 5.71% | -13.16% | -2.34% | -2.19% |
| 1948 | 5.50% | 4.01% | 4.14% | 2.65% |
| 1949 | 18.79% | 31.39% | 3.31% | 7.16% |
| 1950 | 31.71% | 3.25% | 2.12% | 2.01% |
| 1951 | 24.02% | 18.63% | -2.69% | -2.77% |
| 1952 | 18.37% | 19.25% | 3.52% | 2.99% |
| 1953 | -0.99% | 7.85% | 3.41% | 2.08% |
| 1954 | 52.62% | 24.72% | 5.39% | 7.57% |
| 1955 | 31.56% | 11.26% | 0.48% | 0.12% |
| 1956 | 6.56% | 5.06% | -6.81% | -6.25% |
| 1957 | -10.78% | 6.36% | 8.71% | 3.58% |
| 1958 | 43.36% | 40.70% | -2.22% | 0.18% |
| 1959 | 11.96% | 7.49% | -0.97% | -2.29% |
| 1960 | 0.47% | 20.26% | 9.07% | 9.01% |
| 1961 | 26.89% | 29.33% | 4.82% | 4.65% |
| 1962 | -8.73% | -2.44% | 7.95% | 6.55% |
| 1963 | 22.80% | 12.36% | 2.19% | 3.44% |
| 1964 | 16.48% | 15.91% | 4.77% | 4.94% |
| 1965 | 12.45% | 4.67% | -0.46% | 0.50% |
| 1966 | -10.06% | -4.48% | 0.20% | -3.45% |
| 1967 | 23.98% | -0.63% | -4.95% | -3.63% |
| 1968 | 11.06% | 10.32% | 2.57% | 1.87% |
| 1969 | -8.50% | -15.42% | -8.09% | -6.66% |
| 1970 | 4.01% | 16.56% | 18.37% | 15.90% |
| 1971 | 14.31% | 2.41% | 11.01% | 11.59% |
| 1972 | 18.98% | 8.15% | 7.26% | 7.19% |
| 1973 | -14.66% | -18.07% | 1.14% | 2.42% |
| 1974 | -26.47% | -21.55% | -3.06% | -5.28% |
| 1975 | 37.20% | 44.49% | 14.64% | 15.50% |
| 1976 | 23.84% | 31.81% | 18.65% | 19.04% |
| 1977 | -7.18% | 8.64% | 1.71% | 5.22% |
| 1978 | 6.56% | -3.71% | -0.07% | -0.98% |
| 1979 | 18.44% | 13.58% | -4.18% | -2.75% |
| 1980 | 32.42% | 15.08% | -2.76% | -0.23% |
| 1981 | -4.91% | 11.74% | -1.24% | 4.27% |
| 1982 | 21.41% | 26.52% | 42.56% | 33.52% |
| 1983 | 22.51% | 20.01% | 6.26% | 10.33% |
| 1984 | 6.27% | 26.04% | 16.86% | 14.82% |
| 1985 | 32.16% | 33.05% | 30.09% | 26.48% |
| 1986 | 18.47% | 28.53% | 19.85% | 18.16% |
| 1987 | 5.23% | -2.92% | -0.27% | 3.02% |
| 1988 | 16.81% | 18.27% | 10.70% | 10.19% |
| 1989 | 31.49% | 47.80% | 16.23% | 15.61% |
| 1990 | -3.17% | -2.57% | 6.78% | 8.13% |
| 1991 | 30.55% | 14.61% | 19.89% | 19.25% |
| 1992 | 7.67% | 8.10% | 9.39% | 8.65% |
| 1993 | 9.99% | 14.41% | 13.19% | 10.59% |
| 1994 | 1.31% | -7.94% | -5.76% | -4.72% |
| 1995 | 37.43% | 42.15% | 27.20% | 22.81% |
| 1996 | 23.07% | 3.14% | 1.40% | 3.04% |
| 1997 | 33.36% | 24.69% | 12.95% | 11.39% |
| 1998 | 28.58% | 14.82% | 10.76% | 9.44% |
| 1999 | 21.04% | -8.85% | -7.45% | -1.69% |
| 2000 | -9.11% | 59.70% | 12.87% | 9.45% |
| 2001 | -11.88% | -30.41% | 10.65% | 6.85% |
| 2002 | -22.10% | -30.04% | 16.33% | 1.63% |
| 2003 | 28.70% | 26.11% | 5.27% | 10.01% |
| 2004 | 10.87% | 24.22% | 8.72% | 6.03% |
| 2005 | 4.91% | 16.79% | 5.87% | 3.02% |
| 2006 | 15.80% | 20.95% | 3.24% | 3.94% |
| Geometric Mean | 10.10% | 8.80% | 5.85% | 5.45% |
| Arithmetic Mean | 12.03% | 11.14% | 6.17% | 5.73% |
| Standard Deviation | 20.13% | 22.55% | 8.57% | 7.89% |
| Median | 14.31% | 11.74% | 4.14% | 4.45% |

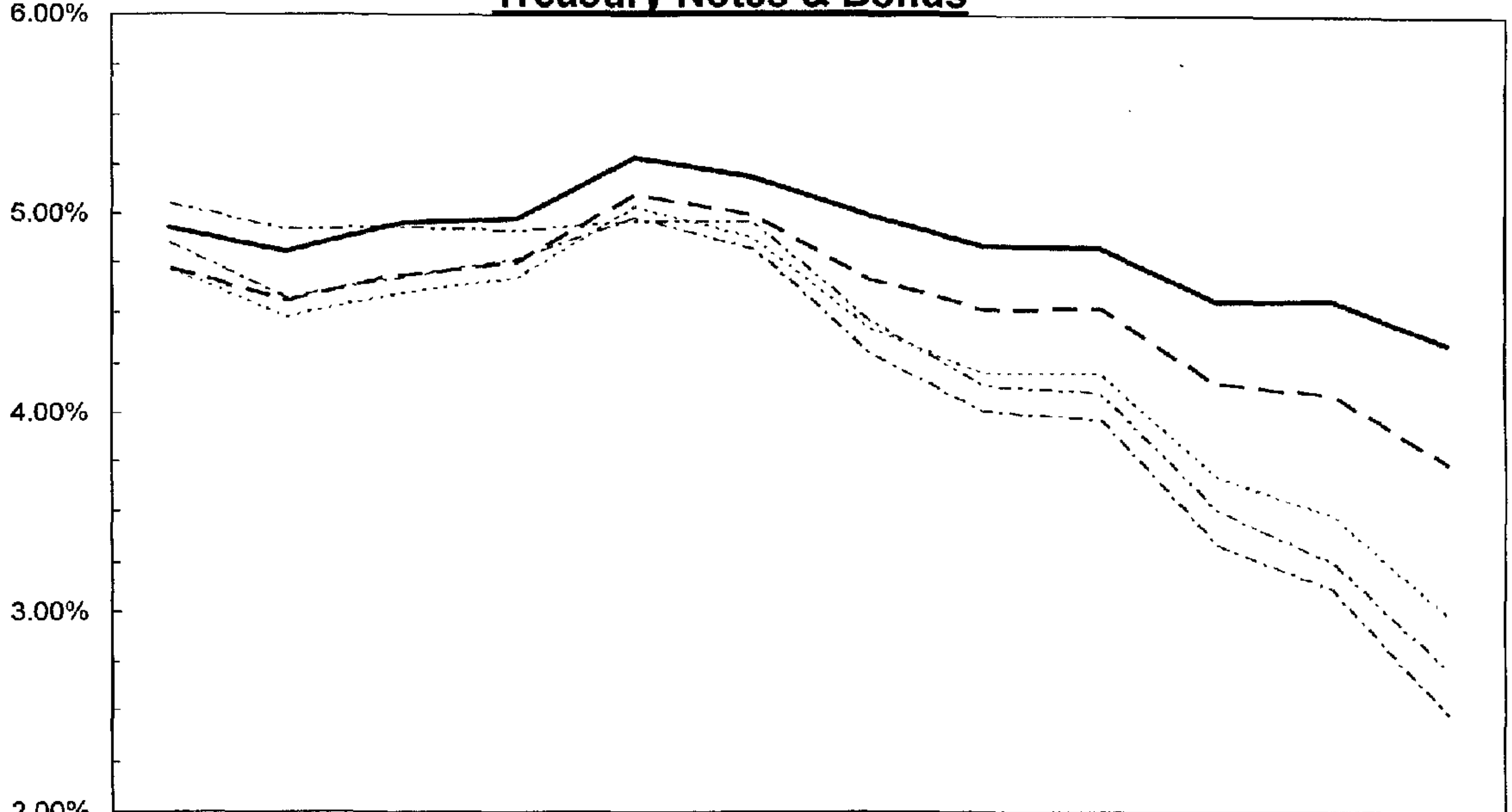
**Tabulation of Risk Rate Differentials for**
**S&P Public Utility Index and Public Utility Bonds**
**For the Years 1928-2006, 1952-2006, 1974-2006, and 1979-2006**

| Total Returns | Range: Geometric Mean | Range: Median | Midpoint | Point Estimate: Arithmetic Mean | Average of the Midpoint of Range and Point Estimate |
|---|---|---|---|---|---|
| **1928-2006** | | | | | |
| S&P Public Utility Index | 8.80% | 11.74% | | 11.14% | |
| Public Utility Bonds | 5.45% | 4.45% | | 5.73% | |
| Risk Differential | 3.35% | 7.29% | 5.32% | 5.41% | 5.37% |
| **1952-2006** | | | | | |
| S&P Public Utility Index | 10.99% | 13.58% | | 12.53% | |
| Public Utility Bonds | 6.17% | 4.94% | | 6.47% | |
| Risk Differential | 4.82% | 8.64% | 6.73% | 6.06% | 6.40% |
| **1974-2006** | | | | | |
| S&P Public Utility Index | 12.79% | 15.08% | | 14.77% | |
| Public Utility Bonds | 8.55% | 8.65% | | 8.90% | |
| Risk Differential | 4.24% | 6.43% | 5.34% | 5.87% | 5.61% |
| **1979-2006** | | | | | |
| S&P Public Utility Index | 13.42% | 15.94% | | 15.27% | |
| Public Utility Bonds | 8.96% | 9.05% | | 9.29% | |
| Risk Differential | 4.46% | 6.89% | 5.68% | 5.98% | 5.83% |

## Value Line Betas

| Proxy Group | |
|---|---|
| AGL Resources, Inc. | 0.85 |
| CH Energy Group | 0.90 |
| Consolidated Edison | 0.75 |
| New Jersey Resources Corp. | 0.85 |
| Northeast Utilities | 0.80 |
| NSTAR | 0.75 |
| PEPCO Holdings | 0.95 |
| Piedmont Natural Gas Co. | 0.85 |
| South Jersey Industries, Inc. | 0.85 |
| WGL Holdings, Inc. | 0.85 |
| Average | 0.84 |

# Yields on Treasury Notes & Bonds




| | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 | Nov-07 | Dec-07 | Jan-08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Year | 5.05% | 4.92% | 4.93% | 4.91% | 4.96% | 4.96% | 4.47% | 4.14% | 4.10% | 3.50% | 3.26% | 2.71% |
| 2-Year | 4.85% | 4.57% | 4.67% | 4.77% | 4.98% | 4.82% | 4.31% | 4.01% | 3.97% | 3.34% | 3.12% | 2.48% |
| 5-Year | 4.71% | 4.48% | 4.59% | 4.67% | 5.03% | 4.88% | 4.43% | 4.20% | 4.20% | 3.67% | 3.49% | 2.98% |
| 10-Year | 4.72% | 4.56% | 4.69% | 4.75% | 5.10% | 5.00% | 4.67% | 4.52% | 4.53% | 4.15% | 4.10% | 3.74% |
| 20-Year | 4.93% | 4.81% | 4.95% | 4.98% | 5.29% | 5.19% | 5.00% | 4.84% | 4.83% | 4.56% | 4.57% | 4.35% |

**Yields for Treasury Constant Maturities**
**Yearly for 2002-2006 and 2007**
**and the Twelve Months Ended January 2008**

| Years | 1-Year | 2-Year | 3-Year | 5-Year | 7-Year | 10-Year | 20-Year |
|---|---|---|---|---|---|---|---|
| 2002 | 2.00% | 2.64% | 3.10% | 3.82% | 4.30% | 4.61% | 5.43% |
| 2003 | 1.24% | 1.65% | 2.10% | 2.97% | 3.52% | 4.02% | 4.96% |
| 2004 | 1.89% | 2.38% | 2.78% | 3.43% | 3.87% | 4.27% | 5.04% |
| 2005 | 3.62% | 3.85% | 3.93% | 4.05% | 4.15% | 4.29% | 4.64% |
| 2006 | 4.93% | 4.82% | 4.77% | 4.75% | 4.76% | 4.79% | 4.99% |
| **Five-Year Average** | 2.74% | 3.07% | 3.34% | 3.80% | 4.12% | 4.40% | 5.01% |
| 2007 | 4.52% | 4.36% | 4.34% | 4.43% | 4.50% | 4.63% | 4.91% |
| **Months** | | | | | | | |
| Feb-07 | 5.05% | 4.85% | 4.75% | 4.71% | 4.71% | 4.72% | 4.93% |
| Mar-07 | 4.92% | 4.57% | 4.51% | 4.48% | 4.50% | 4.56% | 4.81% |
| Apr-07 | 4.93% | 4.67% | 4.60% | 4.59% | 4.62% | 4.69% | 4.95% |
| May-07 | 4.91% | 4.77% | 4.69% | 4.67% | 4.69% | 4.75% | 4.98% |
| Jun-07 | 4.96% | 4.98% | 5.00% | 5.03% | 5.05% | 5.10% | 5.29% |
| Jul-07 | 4.96% | 4.82% | 4.82% | 4.88% | 4.93% | 5.00% | 5.19% |
| Aug-07 | 4.47% | 4.31% | 4.34% | 4.43% | 4.53% | 4.67% | 5.00% |
| Sep-07 | 4.14% | 4.01% | 4.06% | 4.20% | 4.33% | 4.52% | 4.84% |
| Oct-07 | 4.10% | 3.97% | 4.01% | 4.20% | 4.33% | 4.53% | 4.83% |
| Nov-07 | 3.50% | 3.34% | 3.35% | 3.67% | 3.87% | 4.15% | 4.56% |
| Dec-07 | 3.26% | 3.12% | 3.13% | 3.49% | 3.74% | 4.10% | 4.57% |
| Jan-08 | 2.71% | 2.48% | 2.51% | 2.98% | 3.31% | 3.74% | 4.35% |
| **Twelve-Month Average** | 4.33% | 4.16% | 4.15% | 4.28% | 4.38% | 4.54% | 4.86% |
| **Six-Month Average** | 3.70% | 3.54% | 3.57% | 3.83% | 4.02% | 4.29% | 4.69% |
| **Three-Month Average** | 3.16% | 2.98% | 3.00% | 3.38% | 3.64% | 4.00% | 4.49% |

Source: Federal Reserve statistical release H.15

## Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated February 1, 2008

| Year | Quarter | 1-Year Treasury Bill | 2-Year Treasury Note | 5-Year Treasury Note | 10-Year Treasury Note | 30-Year Treasury Bond |
|---|---|---|---|---|---|---|
| 2008 | First | 2.5% | 2.4% | 2.9% | 3.6% | 4.2% |
| 2008 | Second | 2.3% | 2.3% | 2.8% | 3.5% | 4.1% |
| 2008 | Third | 2.4% | 2.4% | 2.9% | 3.6% | 4.2% |
| 2008 | Fourth | 2.5% | 2.6% | 3.1% | 3.8% | 4.3% |
| 2009 | First | 2.8% | 2.9% | 3.3% | 4.0% | 4.5% |
| 2009 | Second | 3.2% | 3.2% | 3.6% | 4.1% | 4.6% |

# THE VALUE LINE Investment Survey®

Part 1 **Summary & Index**

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

**February 8, 2008**

## TABLE OF SUMMARY & INDEX CONTENTS

**Summary & Index Page Number**



### SCREENS



The Median of Estimated
**PRICE-EARNINGS RATIOS**
of all stocks with earnings

**16.0**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 7-13-07 |
|---|---|---|
| 16.5 | 14.1 | 19.7 |

The Median of Estimated
**DIVIDEND YIELDS**
(next 12 months) of all dividend paying stocks under review

**2.1%**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 7-13-07 |
|---|---|---|
| 1.7% | 2.4% | 1.6% |

The Estimated Median Price
**APPRECIATION POTENTIAL**
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

**65%**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 7-13-07 |
|---|---|---|
| 45% | 115% | 35% |

## ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).



*Reviewed in this week's issue.

**In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXIII, No. 24.**
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Table 7

Attachment PRM-13
Page 6 of 6

**Basic Series and Portfolios: Summary Statistics of Annual Total Returns in Percent**

| | 1/1/26 to 12/31/07 | | |
|---|---|---|---|
| Asset Class | Geometric Mean | Arithmetic Mean | Standard Deviation |
| **Large Company Stocks** | 10.4 | 12.3 | 20.0 |
| **Small Company Stocks** | 12.5 | 17.1 | 32.6 |
| **Long-Term Corporate Bonds** | 5.9 | 6.2 | 8.4 |
| **Long-Term Government Bonds** | 5.5 | 5.8 | 9.2 |
| **Intermediate-Term Government Bonds** | 5.3 | 5.5 | 5.7 |
| **U.S. Treasury Bills** | 3.7 | 3.8 | 3.1 |
| **Inflation** | 3.0 | 3.1 | 4.2 |
| **90% Stocks/10% Bonds** | 10.1 | 11.6 | 18.0 |
| **70% Stocks/30% Bonds** | 9.3 | 10.3 | 14.5 |
| **50% Stocks/50% Bonds** | 8.4 | 9.0 | 11.4 |
| **30% Stocks/70% Bonds** | 7.3 | 7.7 | 9.3 |
| **10% Stocks/90% Bonds** | 6.1 | 6.5 | 8.7 |

**Comparable Earnings Approach**
Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++ & A;
Price Stability of 90 to 100; Betas of .75 to .95; and Technical Rank of 3 & 4

| Company | Industry | Timeliness Rank | Safety Rank | Financial Strength | Price Stability | Beta | Technical Rank |
|---|---|---|---|---|---|---|---|
| Allstate Corp. | INSPRPTY | 3 | 1 | A | 95 | 0.95 | 3 |
| Assoc. Banc-Corp | BANKMID | 4 | 2 | B++ | 100 | 0.90 | 3 |
| AutoNation Inc. | RETAUTO | 4 | 2 | B++ | 90 | 0.95 | 4 |
| Avery Dennison | CHEMSPEC | 3 | 2 | A | 90 | 0.90 | 3 |
| BB&T Corp. | BANK | 3 | 1 | A | 95 | 0.95 | 3 |
| City National Corp. | BANK | 4 | 2 | B++ | 95 | 0.85 | 3 |
| ConAgra Foods | FOODPROC | 3 | 2 | B++ | 95 | 0.80 | 3 |
| Harte-Hanks | ADVERT | 4 | 2 | B++ | 90 | 0.80 | 3 |
| HCC Insurance Hldgs. | INSPRPTY | 3 | 3 | B+ | 90 | 0.85 | 3 |
| Huntington Bancshs. | BANKMID | 4 | 3 | B+ | 95 | 0.95 | 3 |
| Int'l Flavors & Frag. | CHEMSPEC | 3 | 2 | B++ | 95 | 0.85 | 3 |
| Int'l Speedway 'A' | RECREATE | 3 | 3 | B+ | 90 | 0.80 | 3 |
| Loews Corp. | FINANCL | 3 | 2 | A | 95 | 0.95 | 3 |
| Lubrizol Corp. | CHEMSPEC | 3 | 3 | B+ | 90 | 0.95 | 3 |
| National City Corp. | BANKMID | 4 | 2 | B++ | 95 | 0.95 | 4 |
| New York Times | NWSPAPER | 3 | 2 | B+ | 90 | 0.80 | 3 |
| Northrop Grumman | DEFENSE | 3 | 1 | A | 95 | 0.85 | 3 |
| Old Republic | INSPRPTY | 4 | 2 | B++ | 95 | 0.95 | 3 |
| Pitney Bowes | OFFICE | 3 | 2 | A | 100 | 0.85 | 3 |
| Regions Financial | BANK | 4 | 1 | A | 95 | 0.90 | 3 |
| Reinsurance Group | INSLIFE | 3 | 1 | A | 95 | 0.85 | 3 |
| Republic Services | ENVIRONM | 3 | 2 | B+ | 95 | 0.80 | 3 |
| Safeco Corp. | INSPRPTY | 4 | 3 | B+ | 95 | 0.80 | 3 |
| Scripps (E.W.) 'A' | NWSPAPER | 3 | 2 | B+ | 95 | 0.85 | 3 |
| Sonoco Products | PACKAGE | 4 | 1 | A | 90 | 0.95 | 3 |
| SunTrust Banks | BANK | 4 | 1 | A | 95 | 0.95 | 3 |
| Valspar Corp. | CHEMSPEC | 4 | 3 | B+ | 95 | 0.90 | 3 |
| Waste Connections | ENVIRONM | 3 | 3 | B+ | 90 | 0.90 | 3 |
| Waste Management | ENVIRONM | 3 | 2 | B++ | 90 | 0.95 | 3 |
| Weis Markets | GROCERY | 3 | 1 | A | 90 | 0.85 | 3 |
| Wilmington Trust | BANK | 4 | 1 | A | 95 | 0.95 | 3 |
| Average | | 3 | 2 | B++ | 94 | 0.89 | 3 |
| Proxy Group | Average | 3 | 2 | B++ | 99 | 0.84 | 3 |

Source of Information: Value Line Investment Survey for Windows, February 2007

**Comparable Earnings Approach**
Five -Year Average Historical Earned Returns
for Years 2002-2006 and
Projected 3-5 Year Returns

| Company | 2002 | 2003 | 2004 | 2005 | 2006 | Average | Projected 2009-12 |
|---|---|---|---|---|---|---|---|
| Allstate Corp. | 11.9% | 12.9% | 14.2% | 8.7% | 22.9% | 14.1% | 17.5% |
| Assoc. Banc-Corp | 16.6% | 17.0% | 12.8% | 13.8% | 14.1% | 14.9% | 14.0% |
| AutoNation Inc. | 9.8% | 9.6% | 8.7% | 8.5% | 9.5% | 9.2% | 9.0% |
| Avery Dennison | 26.5% | 20.1% | 19.8% | 22.3% | 22.6% | 22.3% | 17.5% |
| BB&T Corp. | 17.9% | 10.7% | 14.3% | 14.9% | 13.0% | 14.2% | 15.0% |
| City National Corp. | 16.3% | 15.3% | 15.3% | 16.1% | 15.7% | 15.7% | 15.0% |
| ConAgra Foods | 18.2% | 18.2% | 16.4% | 14.5% | 12.8% | 16.0% | 16.5% |
| Harte-Hanks | 17.0% | 15.7% | 17.1% | 20.4% | 22.7% | 18.6% | 16.0% |
| HCC Insurance Hldgs. | 12.6% | 13.7% | 11.8% | 11.4% | 16.8% | 13.3% | 12.0% |
| Huntington Bancshs. | 14.8% | 17.0% | 15.7% | 16.1% | 15.3% | 15.8% | 11.0% |
| Int'l Flavors & Frag. | 32.0% | 26.9% | 21.5% | 20.1% | 23.6% | 24.8% | 27.0% |
| Int'l Speedway 'A' | 17.1% | 15.0% | 14.7% | 15.3% | 15.0% | 15.4% | 10.5% |
| Loews Corp. | 8.7% | 7.3% | 10.5% | 6.4% | 12.6% | 9.1% | 11.0% |
| Lubrizol Corp. | 14.5% | 9.5% | 9.1% | 11.0% | 12.6% | 11.3% | 15.0% |
| National City Corp. | 19.2% | 22.7% | 17.1% | 15.7% | 15.8% | 18.1% | 12.0% |
| New York Times | 24.1% | 21.5% | 20.9% | 15.4% | 20.5% | 20.5% | 21.0% |
| Northrop Grumman | 4.8% | 4.8% | 6.4% | 7.4% | 9.2% | 6.5% | 12.0% |
| Old Republic | 12.2% | 12.6% | 10.5% | 11.5% | 10.4% | 11.4% | 9.0% |
| Pitney Bowes | 67.0% | 52.3% | 46.0% | 48.1% | 87.0% | 60.1% | 82.5% |
| Regions Financial | 14.8% | 14.6% | 8.1% | 9.4% | 6.5% | 10.7% | 10.5% |
| Reinsurance Group | 10.5% | 8.5% | 9.9% | 8.9% | 10.4% | 9.6% | 11.5% |
| Republic Services | 12.6% | 11.3% | 12.7% | 15.8% | 19.7% | 14.4% | 20.0% |
| Safeco Corp. | 6.1% | 8.1% | 14.5% | 15.8% | 19.9% | 12.9% | 12.0% |
| Scripps (E.W.) 'A' | 15.2% | 13.6% | 13.8% | 13.6% | 15.4% | 14.3% | 12.5% |
| Sonoco Products | 16.5% | 12.5% | 13.6% | 15.2% | 17.7% | 15.1% | 18.0% |
| SunTrust Banks | 15.2% | 13.7% | 9.8% | 11.7% | 11.5% | 12.4% | 10.5% |
| Valspar Corp. | 16.3% | 12.9% | 14.3% | 13.9% | 14.1% | 14.3% | 12.5% |
| Waste Connections | 12.8% | 12.2% | 10.9% | 11.9% | 11.0% | 11.8% | 13.5% |
| Waste Management | 15.2% | 13.2% | 13.7% | 14.3% | 16.0% | 14.5% | 20.5% |
| Weis Markets | 10.4% | 9.5% | 10.0% | 10.5% | 8.9% | 9.9% | 9.5% |
| Wilmington Trust | 18.0% | 16.8% | 15.7% | 17.1% | 13.6% | 16.2% | 17.5% |
| Average | | | | | | 15.7% | 16.5% |
| Median | | | | | | 14.3% | 13.5% |

**BEFORE**
**THE PUBLIC UTILTIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service. | ) ) ) ) | Case No. 08-0072-GA-AIR |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges. | ) ) ) ) | Case No. 08-0073-GA-ALT |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods. | ) ) ) | Case No. 08-0074-GA-AAM |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Revise its Depreciation Accrual Rates. | ) ) ) | Case No. 08-0075-GA-AAM |

**APPENDICES TO ACCOMPANY**
**PREPARED DIRECT TESTIMONY OF**
**PAUL R. MOUL**
**ON BEHALF OF COLUMBIA GAS OF OHIO, INC.**

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

## EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-one (31) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000).

Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

| Date | Occasion | Sponsor |
|---|---|---|
| April 2006 | Thirty-eighth Financial Forum | Society of Utility & Regulatory Financial Analysts |
| April 2001 | Thirty-third Financial Forum | Society of Utility & Regulatory Financial Analysts |
| December 2000 | Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry | Pennsylvania Bar Institute |
| July 2000 | EEI Member Workshop Developing Incentives Rates: Application and Problems | Edison Electric Institute |
| February 2000 | The Sixth Annual FERC Briefing | Except and Bruder, Gentile & Marcoux, LLP |
| March 1994 | Seventh Annual Proceeding | Electric Utility Business Environment Conf. |
| May 1993 | Financial School | New England Gas Assoc. |
| April 1993 | Twenty-Fifth Financial Forum | National Society of Rate of Return Analysts |
| June 1992 | Rate and Charges Subcommittee Annual Conference | American Water Works Association |
| May 1992 | Rates School | New England Gas Assoc. |
| October 1989 | Seventeenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah |
| October 1988 | Sixteenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University |

| | | |
|---|---|---|
| | | of Utah |
| May 1988 | Twentieth Financial Forum | National Society of Rate of Return Analysts |
| October 1987 | Fifteenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah |
| September 1987 | Rate Committee Meeting | American Gas Association |
| May 1987 | Pennsylvania Chapter annual meeting | National Association of Water Companies |
| October 1986 | Eighteenth Financial Forum | National Society of Rate of Return Analysts |
| October 1984 | Fifth National on Utility Ratemaking Fundamentals | American Bar Association |
| March 1984 | Management Seminar | New York State Telephone Association |
| February 1983 | The Cost of Capital Seminar | Temple University, School of Business Admin. |
| May 1982 | A Seminar on Regulation and The Cost of Capital | New Mexico State University, Center for Business Research and Services |
| October 1979 | Economics of Regulation | Brown University |

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

## RATESETTING PRINCIPLES

Traditional cost of service regulation, as implemented by a regulatory agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide the public utility and its investors with an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with customers has been changing, a regulated utility remains quite different from a non-regulated firm, which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests have been articulated through which the regulator can determine the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

**APPENDIX C TO DIRECT TESTIMONY OF PAUL R. MOUL**

## EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms, which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings, which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk, which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

**APPENDIX D TO DIRECT TESTIMONY OF PAUL R. MOUL**

## COST OF EQUITY–GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation, which lacks such a basis, will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods, which have been employed to measure the cost of equity, include: the *Discounted Cash Flow* ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns, which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors.

To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns, which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the landmark decisions on the issue of rate of return. These decisions require that a fair return for a utility must be equal to that earned by firms of comparable risk.

APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

## DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $\$100 \div (1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate, which reflects the risk or uncertainty, associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If $P$ represents price, $Kp$ is the required rate of return on a preferred stock, and $D$ is the annual dividend ($P$ and $D$ with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, $Kp$. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and $n$ approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with $D_1$ = \$1.00, and $P_0$ = \$10, then $Kp$ = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate $(g)$, so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if $Ks$ (the required rate of return on a common stock) is greater than $g$, then the DCF equation can be reduced to: $P_0 = \frac{D_1}{Ks - g}$ or $P_0 = \frac{D_0(1+g)}{Ks - g}$ which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0(1+g)}{P_0} + g$$

[1] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables $D_0$, $P_0$ and $g$ must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend $(D_0)$ of \$0.80, the current price $(P_0)$ of \$10.00, and the investor expected dividend growth rate $(g)$ of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price $(P_0)$ of \$10.00, a dividend $(D_0)$ of \$0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

## Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Attachment PRM-3. The 2002-2006 five-year average dividend yield was 4.2% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Attachment PRM-7. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as $D_0$, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 3.125% (6.25% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.01% (3.89% x 1.03125) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend *($D_0$)* is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.04% (3.89% x 1.03877) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the

$$k=\left[\left(1+\frac{D_0}{P_0}\right)^4-1\right]+g$$

periodic quarterly dividend payments *($D_0$)*, results in a third DCF formulation: This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *($D_0$)*:

$$k=\left[\left(1+\frac{D_0(1+g)^{.25}}{P_0}\right)^4-1\right]+g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 0.9725% (3.89% ÷ 4) for the Gas Group. The compound dividend yield would be 4.01% ($1.009874^4$-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 4.02% forward-looking dividend yield is the average (4.01% + 4.04% + 4.01% = 12.06% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\,(1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

## Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value

Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common

[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*B*x*R*" shown on Attachment PRM-9. Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

## Leverage Adjustment

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

| Gas Group | Capitalization at Market Value (Fair Value) | Capitalization at Book Value (Carrying Amounts) |
|---|---|---|
| Long-term Debt | 33.71% | 46.79% |
| Preferred Stock | 0.62 | 0.88 |
| Common Equity | 65.68 | 52.33 |
| Total | 100.00% | 100.00% |

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

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

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

$$9.20\% = 10.27\% - (((9.20\% - 6.11\%)\ .65)\ 33.71\%/65.68\%) - (9.20\% - 6.13\%)\ 0.62\%/65.68\%$$

where $ku$ = cost of equity for an all-equity firm, $ke$ = market determined cost equity, $i$ = cost of debt[3], $d$ = dividend rate on preferred stock[4], $D$ = debt ratio, $P$ = preferred stock ratio, and $E$ = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 9.20% using the market value of the Gas Group's capitalization. Having

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

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

determined that the cost of equity is 9.20% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

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

$$11.05\% = 9.20\% + (((9.20\% - 6.11\%).65)\ 46.79\%/52.33\%) + (9.20\% - 6.13\%)\ 0.88\%/52.33\%$$

**APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL**

## FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment, which is represented by historical, costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses, which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of *negative market pressure could be the product of the techniques employed to measure pressure* and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Attachment PRM-10. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2002 to 2006. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02, which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

## INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation that is reflected in current interest rates may be quite different from the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve, which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk.

The Treasury has been issuing inflation-indexed notes, which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

**Interest Rate Environment**

Federal Reserve Board ("Fed") policy actions, which impact directly short-term interest rates also substantially, affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system, which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend, which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0%, which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market, which provides ease of trading, and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

## APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds, which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate.

Just after the FOMC meeting on August 7, 2007, where the FOMC decided to retain a

5.25% Fed Funds rate, turmoil in the credit markets prompted central banks throughout the world to inject over $325 billion of reserves into the banking system over a three-day period in reaction to a credit crunch. Problems had been developing earlier in 2007, beginning in the market for asset-backed securities linked to subprime mortgages. Valuation uncertainties for these securities caused liquidity concerns for hedge funds, investment banks, and financial institutions. The market for commercial paper, the most liquid part of the credit markets for non-Treasury securities, was also affected. In response to the market turmoil, the FOMC issued the following statement, the first of its type since after the September 11, 2001 terrorists' attack.

> "The Federal Reserve is providing liquidity to facilitate the orderly functioning of financial markets.
>
> The Federal Reserve will provide reserves as necessary through open market operations to promote trading in the federal funds market at rates close to the Federal Open Market Committee's target rate of 5-1/4 percent. In current circumstances, depository institutions may experience unusual funding needs because of dislocations in money and credit markets. As always, the discount window is available as a source of funding."

Then, one week after its initial announcement, the FOMC made a surprise reduction of 50 basis points in the discount rate to narrow the spread between this rate and the target Fed Funds rate. At the same time, the FOMC made the following statement:

> "Financial market conditions have deteriorated, and tighter credit conditions and increased uncertainty have the potential to restrain economic growth going forward. In these circumstances, although recent data suggest that the economy has continued to expand at a moderate pace, the Federal Open Market Committee judges that the downside risks to growth have increased appreciably. The Committee is monitoring the situation and is prepared to act as needed to mitigate the adverse effects on the economy arising from the disruptions in financial markets."

Thereafter, at its regularly scheduled meeting on September 18, 2007, the FOMC reduced the target Fed Funds rate to 4.75% and the discount rate was reduced to 5.25% in an effort to forestall the adverse effects of the financial market turmoil on the economy generally. Further reductions of 25 basis points occurred at the next two FOMC meetings on October 31, 2007 and on December 11, 2007. The December 11, 2007 FOMC statement indicated that:

> Incoming information suggests that economic growth is slowing, reflecting the intensification of the housing correction and some softening in business and consumer spending. Moreover, strains in financial markets have increased in recent weeks. Today's action, combined with the policy actions taken earlier, should help promote moderate growth over time.
>
> Readings on core inflation have improved modestly this year, but elevated energy and commodity prices, among other factors, may put upward pressure on inflation. In this context, the Committee judges that some inflation risks remain, and it will continue to monitor inflation developments carefully.
>
> Recent developments, including the deterioration in financial market conditions, have increased the uncertainty surrounding the outlook for economic growth and inflation. The Committee will continue to assess the effects of financial and other developments on economic prospects and will act as needed to foster price stability and sustainable economic growth.

With these actions, the Fed Funds rate and the discount rate closed the calendar year 2007 at 4.25% and 4.75%, respectively.

In 2008, the FOMC again acted decisively in response to further deterioration of credit conditions and perceived weakness in the economy. Acting prior to its first regularly scheduled meeting in 2008, the FOMC reduced the fed funds target by 75 basis points to 3.50% and the discount rate was reduced by a corresponding amount to 4.00%. Actions by the FOMC between meetings are unusual occurrences in recent years, thereby signifying the urgency that the FOMC saw in taking immediate action on monetary policy. Then on January 30, 2008, the fed funds target rate and discount rate were further reduced by 50 basis points, bringing those rates to 3.00% and 3.50%, respectively. In taking this action, the FOMC stated:

> Financial markets remain under considerable stress, and credit has tightened further for some businesses and households. Moreover, recent information indicates a deepening of the housing contraction as well as some softening in labor markets.
>
> The Committee expects inflation to moderate in coming quarters, but it will be necessary to continue to monitor inflation developments carefully.
>
> Today's policy action, combined with those taken earlier, should help to promote moderate growth over time and to mitigate the risks to economic activity. However, downside risks to growth remain. The Committee will continue to assess the effects of financial and other developments on economic prospects and will act in a timely manner as needed to address those risks.

**Public Utility Bond Yields**

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix H. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim, which lenders have on the earnings, and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Attachment PRM-11 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds, which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Attachment PRM-11. There, it is shown that those spreads were about one percentage point during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Attachment PRM-11, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005, 1.08% in 2006, and 1.16% in 2007. As shown by the monthly data presented on pages 4 and 5 of Attachment PRM-11, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.22 percentage points for the twelve-months ended January 2008. For the six- and three-month periods ending January 2008, the yield spread was 1.42% and 1.56%, respectively. Beginning in January 2008, spreads widened significantly with the development of the credit crunch.

**Risk-Free Rate of Return in the CAPM**

Regarding the risk-free rate of return (see Appendix I), pages 2 and 3 of Attachment PRM-13 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

**APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL**

## RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future payments are known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors, which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix G, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

## Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns, which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors" motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Attachment PRM-12 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return, which divides the entire series of annual returns in half, and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix I, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, the risk premiums for each class of equity are:

| | S&P Composite | S&P Public Utilities |
|---|---|---|
| Arithmetic Mean | 5.86% | 5.41% |
| Geometric Mean | 4.25% | 3.35% |
| Median | 10.17% | 7.29% |
| Midpoint of Range | 7.21% | 5.32% |
| Average | 6.54% | 5.37% |

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Attachment PRM-12 should also be considered. One of these sub-periods included the 54-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord, which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Attachment PRM-12.

## APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

## CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium, which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line, which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

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

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

## Beta

The beta coefficient is a statistical measure, which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price, which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment, which has a beta less than 1.0, is considered to be less risky than the market.

The beta coefficient *("$\beta$")*, the one input in the CAPM application, which specifically applies to an individual firm, is derived from a statistical application, which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination ($R^2$) are low.

Page 1 of Attachment PRM-13 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

## Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the February 8, 2008 edition of The Value Line Investment Survey Summary and Index, (see page 5 of Attachment PRM-13) the total return on the universe of Value Line equities is:

| | Dividend Yield | + | Median Appreciation Potential | = | Median Total Return |
|---|---|---|---|---|---|
| As of February 8, 2008 | 2.1% | + | 13.34%[1] | = | 15.44% |

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 13.76%.

DCF Result for the S&P 500 Composite

| D/P | ( | 1+.5g | ) | + | g | = | k |
|---|---|---|---|---|---|---|---|
| 2.21% | ( | 1.05750 | ) | + | 11.42% | = | 13.76% |

| | | | | | |
|---|---|---|---|---|---|
| where: | Price (P) | at | 31-Jan-2008 | = | 1378.55 |
| | Dividend (D) | for | 4th Qtr. '07 | = | 7.62 |
| | Dividend (D) | | annualized | = | 30.48 |
| | Growth (g) | | First Call EpS | = | 11.42% |

Using these indicators, the total market return is 14.60% (15.44% + 13.76% = 29.20% ÷ 2) using both the Value Line and S&P derived returns. With the 14.60% forecast market return and the 4.50% risk-free rate of return, a 10.10% (14.60% - 4.50%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term

[1] The estimated median appreciation potential is forecast to be 65% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 13.34% (i.e., $1.65^{.25}$ - 1).

historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Attachment PRM-13. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Attachment PRM-13, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

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

For the CAPM, a market premium of 8.30% (6.5% + 10.10% = 16.60% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 10.10% using forecasts.

APPENDIX J TO DIRECT TESTIMONY OF PAUL R. MOUL

## COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

## Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

## Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

## Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

Columbia Exhibit No.

**BEFORE**
**THE PUBLIC UTILTIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service. | ) ) ) ) | Case No. 08-0072-GA-AIR |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges. | ) ) ) ) | Case No. 08-0073-GA-ALT |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods. | ) ) ) | Case No. 08-0074-GA-AAM |
| In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Revise its Depreciation Accrual Rates. | ) ) ) | Case No. 08-0075-GA-AAM |

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**PREPARED DIRECT TESTIMONY OF**
**STEPHANIE D. NOEL**
**ON BEHALF OF COLUMBIA GAS OF OHIO, INC.**

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- [ ] **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**
- [X] **OPERATING INCOME**
- [ ] **RATE BASE**
- [ ] **ALLOCATIONS**
- [ ] **RATE OF RETURN**
- [ ] **RATES AND TARIFFS**
- [ ] **OTHER**

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Attorneys for
**COLUMBIA GAS OF OHIO, INC.**

**March 17, 2008**

PREPARED DIRECT TESTIMONY OF STEPHANIE D. NOEL

**Q: Please state your name and business address.**

A: My name is Stephanie D. Noel and my business address is 200 Civic Center Drive, Columbus Ohio 43215.

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

A. I am employed by Columbia Gas of Ohio, Inc. ("Columbia"). My current title is Director, Regulatory Affairs.

**Q. What is your educational background and professional experience?**

A. I graduated from The Ohio State University in 1994 with a Bachelor of Science in Business Administration degree. I joined the accounting firm Arthur Andersen as an auditor in 1994, and became a licensed CPA in 1995. I began my career with Columbia in 1996 as a Senior Accounting Analyst and have held positions with NiSource Corporate Services Company and Columbia of increasing responsibility within the General Accounting, Finance, Regulatory Accounting departments and most recently Regulatory Affairs. In July 2007, I assumed my current position, Director, Regulatory Affairs. I am currently a member of the Ohio Society of CPAs.

**Q. What are your job responsibilities as Director, Regulatory Affairs?**

A. As director of Regulatory Affairs, my primary responsibilities include the planning, supervision, preparation and support of all Columbia's regulatory filings before the Public Utilities Commission of Ohio ("Commission"). These responsibilities include the prepa-