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ration of exhibits, proposed tariff changes and testimony filed by Columbia in support of this general rate proceeding.

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

A. I sponsor Schedules C-1, C-2, C-2.1, C-3, C-3.1 through C-3.21, C-3.23, and C-7.

Q. What is the source of the information contained in the schedules you are sponsoring?

A. The source of the information primarily is Columbia's General Ledger accounting records for actual data and its approved financial plan for forecasted data.

Q. Please Describe Schedule C-1.

A. Schedule C-1 is a jurisdictional, pro forma income statement for the test year. It summarizes Columbia's adjusted revenues and expenses as shown on Schedule C-2 as well as the pro forma income statement based on the proposed rates indicated in Section E-4. The pro forma results were developed by calculating the operating effect of the requested increase and adding it to the adjusted revenue and expense amounts.

Q. Please Describe Schedule C-2.

A. Schedule C-2 is a summary of Columbia's jurisdictional adjusted operating income for the test year at current rates. This schedule includes unadjusted jurisdictional revenue and expense amounts from Schedule C-2.1 and a summary of the adjustments shown on

Schedule C-3. The summarized unadjusted test year income and expense and the related adjustments are summed to arrive at adjusted operating income and expenses.

Q. Please Describe Schedule C-2.1.

A. Schedule C-2.1 details the unadjusted test period operating revenue and expenses, by FERC account number. Test year income and expenses comprise three months of actual data and nine months of forecasted data. These amounts were derived from Columbia's financial plan and General Ledger records and are summarized and carried forward to Schedule C-2. Columbia's gas operations are 100% jurisdictional because the rates proposed in this proceeding apply to all of Columbia'sservice territories and all service areas are jurisdictional.

Q. Please Describe Schedule C-3 and the adjustments detailed on schedules C-3.1 through C-3.26.

A. The adjustments shown on Schedule C-2 are supported by the summary information contained in Schedule C-3 and its corresponding detailed information shown in *Schedules C-3.1 through C-3.26.* The adjustments are made to reflect annualizations, reclassifications, normalizations, additions and eliminations to derive an income statement for the test year that accurately portrays Columbia's financial condition under current rates and provides an appropriate basis for setting rates. The federal income tax effect of each of these adjustments is detailed on Schedule C-3 Line No. 16.

Q. Why are adjustments to test year actual and budget information necessary?

A. These adjustments are required to reflect the ongoing level of revenues and expenses that Columbia would experience in a normal year. Some adjustments are required to even out or eliminate the impacts of journal entries made to the actual book accounting data that comprise the first three months in our test year. Other adjustments are to reflect the level of revenue and expense that would have occurred had all known prospective changes been in effect during the entire test year.

The test year adjustments ensure that prevailing revenues and expenses are properly included in the determination of an ongoing level of rates. Not capturing these adjustments and reflecting them in Columbia's test year would impair Columbia's ability to earn a fair rate of return or could result in Columbia's over-recovering its costs.

Q. What is the purpose of the revenue annualization adjustments shown on Schedules C-3.1 and C-3.2?

A. There are three parts to the adjustment shown on Schedules C-3.1 and 2. The Gas Cost Recovery ("GCR") portion of revenues is detailed on Schedule C-3.2 and all remaining customer revenues are detailed on Schedule C-3.1. The first adjustment shown on each of the schedules is needed to synchronize test year operating revenues based on projected test year volumes that have been normalized for the effect of weather based on 30-year normalization. Actual weather during the test period may differ substantially from normal weather and, as a result, actual customer usage will vary from normal. Revenue must be adjusted for this difference between actual and normal usage or the test year revenue would be different from what would be expected in a normal year.

The second adjustment is to weather normalize the test year sales using 20-year weather averages. Columbia witness William Gresham indicates the most recent data supports Columbia's proposal to weather normalize test year sales using a 20-year weather average because the proposed 20-year averages capture more recent data and the 20-year average is a superior predictor of one-year ahead weather.

Columbia sold approximately 5,300 customers to Northeast Ohio Natural Gas Company on February 6, 2008, which was subsequent to the development of the budgeted data included in the test year. The sale was approved by the Commission in Case No. 07-767-GA-ATR and included customers and all assets associated with those customers. The final adjustment shown on Schedules C-3.1 and C-3.2 is to remove the revenues embedded in the test year related to this sale. The corresponding net plant investment was removed as an adjustment on Schedules B-2 and B-3.

In each case, normalized sales volumes were priced using current base rates to arrive at adjusted base revenues. Rider revenues, including the GCR, Percentage of Income Payment Plan ("PIPP") Program, Uncollectible Expense Rider, Distribution Tax and Ohio Excise Tax Rider, were determined by applying the latest known rates to the applicable 30-year and 20-year normalized volumes. Offsetting expenses included in test year operating expenses were adjusted accordingly on subsequent schedules to reflect normalized usage patterns.

Q. Please describe the other revenue annualization adjustment shown on Schedule C-3.3.

A. Columbia proposes to begin crediting bad check and late payment revenues toward amounts that would otherwise be recovered through its uncollectibles expense adjustment mechanism. By crediting late payment receipts in that manner, Columbia is able to offset a portion of the costs associated with unpaid bills, and parties in the case avoid the debate over the appropriate amount of revenue that should be credited to the cost of service. Schedule C-3.3 reflects the elimination of bad debt and late payment revenues that will be credited back to customers in its entirety if this proposed treatment is approved.

Q. Why did Columbia eliminate unbilled revenue on Schedule C-3.4?

A. Columbia eliminated the estimated unbilled revenue from its operating results to be consistent with the revenue and volume computations contained on Schedule E-4. The revenue and volume amounts on Schedule E-4 are adjusted test year billed volumes and as such, do not include unbilled volume estimates.

Q. Why did Columbia eliminate non-traditional revenue on Schedule C-3.5?

A. Forecasting non-traditional revenue is complex because it is dependant on many market conditions and operational constraints. As a result, treatment of these revenues has been addressed in a separate stipulation in Case Nos. 04-221-GA-GCR, 05-221-GA-GCR AND 96-1113-GA-ATA, filed with the Commission on December 28, 2007. Schedule C-3.5 removes non-traditional revenues because they have been addressed elsewhere and the corresponding expense was properly removed on Schedule C-3.6.

Q. What is the gas cost expense annualization adjustment shown on Schedule C-3.6?

A. Schedule C-3.6 adjusts gas cost expense to synchronize test year gas expenses with revenue. This adjustment is necessary because Columbia recovers 100% of its costs for purchasing the gas commodity, nothing more or less. Therefore, no difference should exist between the adjusted gas revenue and the adjusted gas expense in a test year. The adjustment was calculated by taking the adjusted normalized volumes used in the revenue annualizations shown on Schedules C-3.1 and 2, multiplying them by the February 2008 Expected Gas Cost rate of $10.9592 and comparing the result to test year gas cost expenses.

The difference between the adjustment to gas cost expense shown on Schedule C-3.6 and the adjustment to gas cost revenue as reported on Schedule C-3.1 represents the elimination of non-traditional gas cost expenses. It was necessary to eliminate non-traditional gas cost expenses because the offsetting revenues were eliminated on Schedule C-3.5. After the adjustments on Schedule C-3.2 and C-3.6 have been made, the revenues related to the gas cost portion of the test year revenues equal the adjusted gas cost expenses. The end result is that there is no impact on operating income for these two items.

Q. Please describe the uncollectible expense adjustment shown on Schedule C-3.7.

A. Uncollectible expense is comprised of PIPP and normal bad debt expense. Schedule C-3.7 reflects the annualization of the Uncollectible Expense to the amount of adjusted normalized volumes calculated on Schedule C-3.1. This adjustment is required to synchronize Uncollectible and PIPP revenues as reported on Schedule C-3.1 with Uncollectible Expense. Adjusted Uncollectible Expense was calculated by multiplying the applicable normalized volumes by the currently effective tariff rates and comparing this result to test year uncollectible expense.

Q. Why are the adjusted amounts shown as Uncollectible Revenue on Schedule C-3.1 slightly higher than the adjusted amounts shown as Uncollectible Expense on Schedule C-3.7?

A. The current rate for the Uncollectible Expense Rider includes a component for Ohio Excise tax, thus the revenue collected from the Uncollectible Expense Rider is greater than the associated uncollectible expenses. The difference between the two is properly included in adjusted test year Ohio Excise tax expense as shown on Schedule C-3.19.

Q. What is the adjustment for annualized test year wages shown on Schedule C-3.8?

A. This adjustment represents the annualized effect of labor cost increases occurring or anticipated to occur during the test year and includes any corresponding increases in overtime. The adjustment includes known wage increases based on existing union labor agreements, as well as non-union increases expected during the first quarter of 2008. Consistent with other operations and maintenance expenses; the portion of the labor cost increase that would be capitalized has been excluded. The annualized wages/salaries reflect labor cost increases that are known and measurable and representative of the levels of expense that will be incurred when the proposed rates become effective. Annualized costs were then compared with test year expenses to determine the adjustment.

Columbia witness Joel Hoelzer describes Columbia's compensation structure. He also supports the market competitiveness of Columbia's base salaries and annual merit increases in comparison to utilities and other employers, for both Ohio and nationwide.

Q. Please explain the incentive compensation adjustment shown on Schedule C-3.9.

A. As indicated in the direct testimony of Columbia witness Joel Hoelzer, incentive compensation is part of the "total rewards" philosophy that Columbia uses to ensure it competitively compensates and is able to attract, retain, and motivate qualified employees. Columbia has paid incentive rewards to employees in four of the past five years. The adjustment shown on Schedule C-3.9 adjusts annual incentive plan expense included in test year operating expenses to reflect the five-year average incentive plan level as detailed on WCP3-9a.

Q. What is the pension and benefits expense adjustment shown on Schedule C-3.10?

A. Columbia witness Joel Hoelzer describes the benefit plans offered to Columbia employees, including medical, dental, vision, life insurance, and retirement benefits. He further explains how Columbia manages its benefit costs while balancing a competitive benefit structure for its employees. Pension and benefits expense have been annualized to reflect 2008 benefit elections for active employees, as provided by Hewitt. The most recent Hewitt actuarial studies were used to estimate retiree benefits. Other known and measurable changes in benefit expense levels were incorporated when possible. Adjusted test year expense shown on Schedule C-3.10 is reflective of the levels of expense that will be incurred when the proposed rates become effective, net of anticipated employee/retiree contributions.

Q. Please explain the Post in Service Carrying Charges adjustment shown on Schedule C-3.11.

A. Schedule C-3.11 adjusts operating income to annualize the amortization of post-in-service carrying costs approved in Case No. 94-987-GA-AIR and accrued as of December 31, 2007. This adjustment is necessary because these costs were not included in Columbia's budget, which is the basis for unadjusted test year expenses.

Q. Please explain the adjustment to O&M expense shown on Schedule C-3.12.

A. Included in unadjusted test year expense are dues and memberships, sales, advertising/sponsorships, lobbying, and charitable contributions that are not recoverable in gas distribution rates. For purposes of setting rates, Columbia has eliminated these charges by reducing test year O&M expense by $3,081,000.

Q. Please explain the adjustment to interest on customers' deposits as shown on Schedule C-3.13.

A. Interest expenses are not generally included in operating expenses because deposits are treated as a non-investor source of funds in the development of base rates. Schedule C-3.13 adjusts operating expenses to capture interest on customer service deposits as test year operating expenses. The adjustment is calculated based on a thirteen-month average customer deposit balance multiplied by the annual interest rate of 3 percent, in accordance with the provisions of Ohio Revised Code Section 4933.17.

Q. Please describe the rate case adjustment shown on Schedule C-3.14.

A. Schedule C-3.14 reflects the estimated costs of this proceeding amortized over three years. The details of these costs are contained in Schedule C-8, which is supported in direct testimony by Larry W. Martin. Such expenses are considered to be incremental since they have not been included in the test year amount for FERC account 928, regulatory commission expense, or in any other expense category shown on Schedule C-2.1. Columbia proposes to defer this expense and amortize it over a three-year period.

Q. What is the adjustment to WarmChoice shown on Schedule C-3.15?

A. The WarmChoice adjustment detailed on Schedule C-3.15 consists of two parts. The first part reflects an adjustment to increase operating expenses for weatherization expenses deferred in excess of the amount that has been amortized. The unamortized balance of Columbia's WarmChoice program as of December 31, 2007 was $4.4 million. Columbia proposes a three-year amortization, resulting in an annual increase to test year operating expenses of $1.4 million.

The revenue requirement in Case No. 94-987-GA-AIR included a WarmChoice annual expense totaling $5,090,000. In 2003, Columbia agreed to fund an additional $500,000 to its WarmChoice program as part of Case No. 03-1127-GA-UNC. The second part of the adjustment shown on Schedule C-3.15 reflects Columbia's proposal to increase its current WarmChoice program from the approved $5.5 million level to $7.1 million, reflecting inflation since the last rate case.

As indicated on Schedule C-3.15, test year WarmChoice expense was $4.5 million, which is less than the above mentioned, $5.5 million approved level. The reason for the difference between what was budgeted as test year WarmChoice expense and what was approved as WarmChoice expense in prior cases results from a decrease in throughput of 10.77% between the volumes included in Case No. 94-687-GA-AIR and the unadjusted test year volumes of this rate case. The decrease in throughput is also the primary driver for the existence of the deferred WarmChoice balance.

Q. How does Columbia account for WarmChoice revenue and expenses?

A. WarmChoice expenditures are recorded to a deferred 182 FERC account. Columbia has committed to $5.5 million of WarmChoice expenditures each year, which will ultimately increase the deferred 182 balance each year. Each month, the amount of the deferral is reduced by the WarmChoice revenue actually collected from Columbia customers and an offsetting entry is recorded to O&M expense. This treatment ensures that WarmChoice revenues equal WarmChoice expenses in a given year. As a result, when throughput is less than the 1994 rate case levels, annual WarmChoice amortization is less than the annual expenditures because the amount of base rate revenue collected has decreased.

Q. Is Columbia proposing additional Demand Side Management ("DSM") measures?

A. Yes. Columbia witnesses Tom Brown and Larry Martin will provide further details related to the proposed DSM rider, which has been filed as part of Columbia's Alternative Regulation Plan.

Q. What is the purpose of the adjustment to O&M detailed on Schedule C-3.16?

A. Schedule C-3.16 adjusts operating income for known changes in O&M expenses since the preparation of Columbia's official operating budget. It also removes the impact of non-routine entries recorded to actual O&M expense during the first three months of the test year.

Q. Please explain the depreciation expense adjustment on Schedule C-3.17.

A. The first adjustment on Schedule C-3.17 adjusts test year depreciation and amortization expense to the level of expense determined by applying current depreciation rates to property balances as of December 31, 2007, the date certain. The amount of this adjustment is the difference between unadjusted test year total depreciation and amortization expense shown on Schedule C-2.1 and the total depreciation and amortization expense at current rates shown on Schedule B-3.2.

The second adjustment shown on Schedule C-3.17 is needed to reflect total depreciation and amortization expense on date certain property at newly proposed depreciation rates. The proposed rates are supported by the latest depreciation study performed by Gannett-Fleming and Columbia witness John Spanos. The amount of this adjustment totals $611,000 and reflects the difference between the total depreciation and amortization expense on date certain property at current rates and total depreciation and amortization expense on date certain property at proposed depreciation rates.

Q. What is the payroll tax adjustment on Schedule C-3.18?

A. Schedule C-3.18 shows an adjustment to taxes other than income taxes to reflect payroll tax expenses commensurate with the adjusted test year labor costs detailed on Schedules C-3.8 and 9. Included in the calculation of this adjustment are the F.I.C.A taxes and federal and state unemployment taxes determined by applying current tax rates to adjusted test year taxable wages.

Q. Please explain the Ohio Excise Tax Adjustment shown on Schedule C-3.19.

A. The adjustment shown on Schedule C-3.19 annualizes the Ohio Excise Tax Expense to the level of expense to be recognized based on adjusted test year operating revenues reduced for projected non-taxable revenues. The second adjustment shown on Schedule C-3.19 annualizes pro forma Ohio Excise Tax based on pro forma revenue as detailed on Schedule C-1.

Q. Please explain the PUCO and OCC tax adjustments shown on Schedule C-3.20.

A. Schedule C-3.20 decreases other tax expense by $301,000 to capture the PUCO and OCC assessments at the latest known levels. This adjustment is necessary to state PUCO and OCC tax expense at a level that is representative of the level that will exist when rates will go into effect.

Q. Why is distribution tax adjusted on Schedule C-3.21?

A. The distribution tax adjustment shown on Schedule C-3.21 is necessary to synchronize distribution tax expense levels with the revenues reported on Schedule C-3.1.

Q. Please describe the other tax adjustments made on Schedule C-3.23.

A. Schedule C-3.23 annualizes the Department of Energy assessment based on adjusted test year customer counts and 20-year normalized volumes. The adjustment decreases other taxes by $9,000.

Q. Are there other Schedule C-3 adjustments that you have not explained?

A. Yes. Schedule C-3.22, adjustment to property taxes is addressed in the direct testimony of Columbia witnesses Larry W. Martin. Tax adjustments have been made on Schedules C-3.24 through C-3.26 and are addressed in the direct testimony of Panpilas W. Fischer.

Q. Please describe Schedule C-7.

A. Schedule C-7 provides detail, by account, of test year Customer Service and Informational Expense, Sales Expense, and General Advertising Expense. Each type of expense is further detailed on this schedule by its labor and non-labor components.

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

PREPARED DIRECT TESTIMONY OF
DAVID A. ROY
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

☐ **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**

☐ **OPERATING INCOME**

☐ **RATE BASE**

☐ **ALLOCATIONS**

☐ **RATE OF RETURN**

☐ **RATES AND TARIFFS**

[X] **OTHER**

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COLUMBIA GAS OF OHIO, INC.

March 17, 2008

PREPARED DIRECT TESTIMONY OF DAVID A. ROY

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is David A. Roy and my business address is 200 Civic Center Drive, Columbus, OH 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 Manager, Field Engineering.

Q. What are your responsibilities as Manager, Field Engineering?

A. As Manager, Field Engineering, my principal responsibilities include the development and monitoring of Columbia's capital budget. I oversee the identification, planning, and design of virtually all capital work for Columbia's gas distribution system. I also ensure the personal and professional development of the Field Engineering staff.

Q. What is your educational background?

A. I have a Bachelor of Science degree in Electrical Engineering from Purdue University, West Lafayette, Indiana and a Master's degree in Business Administration from DePaul University, Chicago, Illinois.

Q. Please briefly describe your professional experience.

A. I joined NiSource as an Associate Trainee in 1999 where I rotated through various operating, engineering, and business departments to gain a broad understanding of the company. In 2000 I accepted a position with the Northern Indiana Public Service Company ("NIPSCO") Engineering department as a Distribution Project Engineer. I was responsible for planning and designing natural gas and electric distribution systems. I joined the NIPSCO Operations department in 2003 as a Construction & Maintenance Supervisor and was later promoted to Service Commitment Supervisor in 2004. While in these positions I had responsibilities including, but not limited to, overseeing electric line and gas service crews, managing local new business work, overseeing annual gas and electric compliance work, and developing the local capital budget. In 2006, I was promoted to my current position of Manager, Field Engineering for Columbia.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I will provide a general overview of Columbia's operating territory and gas distribution system, and will review Columbia's recent operating performance. I am also supporting various portions of Rider IRP. The primary components of Rider IRP which I will be supporting are Columbia's Accelerated Main Replacement Program ("AMRP") and the assumption of future installation, maintenance, repair and replacement of customer service lines and the replacement of all prone to failure risers. This request includes existing customer services lines, as well as new service line installations. The Automatic Meter Reading Device ("AMRD") component of Rider IRP will be supported by Brad Bohrer. In addition to my testimony, Columbia has retained Steven Vitale of Black & Veatch

Corporation ("Black & Veatch") to render an independent opinion as to the need and appropriateness of Columbia's proposed AMRP.

Q. Please summarize your testimony.

A. Section III provides an overview of Columbia's operating territory and gas distribution system. Section IV discusses Columbia's recent operating performance. Section V discusses various components of Rider IRP, including the proposed AMRP. Section VI discusses Columbia's request to assume financial responsibility for existing and future customer service lines and replacement of prone to failure risers.

III. OVERVIEW OF COLUMBIA'S OPERATING TERRITORY AND GAS DISTRIBUTION SYSTEM

Q. What geographic areas does Columbia serve today?

A. Columbia is the largest natural gas utility in the State of Ohio. Columbia's service territory stretches from some of the northern most areas of the state to some of the most southern. Columbia serves customers in 60 of Ohio's 88 counties. Some of the primary metropolitan areas that Columbia serves include Columbus, Toledo, Parma, Mansfield, and Springfield.

Q. Please describe Columbia's gas distribution system.

A. Columbia was incorporated in 1961 after numerous consolidations spanning many years. As a result of these consolidations, Columbia's distribution system consists of many different independent systems and various types of pipe. These distribution systems ultimately deliver natural gas to approximately 1,400,000 Columbia residential, commercial, and industrial customers.

Q. What role does Columbia serve in delivering gas to its end use customers?

A. Columbia's distribution infrastructure constitutes the final step in the delivery of natural gas to customers from the producing regions of the southern United States and rural areas of Ohio. Columbia distributes natural gas by taking it from delivery points ("city gates") along interstate and intrastate pipelines, then transporting it through approximately 19,600 miles of relatively small-diameter distribution main that network underground between and through cities, towns and neighborhoods. The natural gas is then delivered via approximately 1,330,000 customer service lines to meet the demands of Columbia's residential, commercial and industrial end-use customers.

Columbia takes title of the natural gas commodity at the city gate and then steps down the transmission pressure to local distribution pressure. An odorant known as mercaptan is typically added to the natural gas before it is delivered into the distribution system. The gas is then released into the Columbia distribution system where additional pressure reduction typically occurs in a series of district regulator stations before being delivered to each customer. In sum, Columbia's distribution system moves relatively small volumes of natural gas at lower pressures over shorter distances to a far greater number of individual users than its interstate pipeline counterparts.

IV. HISTORIC OPERATING PERFORMANCE

Q. Has Columbia established documented operation and maintenance ("O&M") plans for conducting O&M activities and emergency response?

A. Yes. Minimum Federal Safety Standards require that each operator prepare and follow a manual of written procedures for this purpose. Columbia maintains an O&M manual for conducting O&M activities and emergency response.

Q. Are there any particular guidelines Columbia uses as reference for maintaining and updating the O&M manual?

A. Yes. Columbia has adopted all federal and state requirements.

Q. Does Columbia meet state and federal requirements for operating its natural gas distribution system?

A. Yes. Columbia performs numerous safety related inspections and tests of its facilities according to the U.S. Department of Transportation ("DOT") and the Public Utilities Commission of Ohio regulations. In particular, DOT Part 192.723 requires operators to conduct comprehensive leakage surveys in business districts at intervals not exceeding fifteen (15) months, but at least once per calendar year. In non-business districts, DOT requires leak surveys at intervals not exceeding five (5) years unless the pipes involved are unprotected steel, in which case it is every three (3) years.

Q. In what way does Columbia manage or classify its leak backlog and repairs?

A. Columbia classifies each gas leak according to its severity: Grade "1," Grade "2 Priority," Grade "2" or Grade "3." A Grade "1" leak is a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. A Grade "2 Priority" leak is a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair in a few days. Grade "2 Priority" leaks shall be cleared no later than 21 calendar days from the date found. A Grade "2" leak is a leak that represents leakage areas in which the associated hazard does not mandate immediate action, but justifies scheduled repair based on probable future hazard. A Grade "2" leak must either be repaired within fifteen months or eliminated by replacing the pipeline containing the leak within twenty-four months from the date discovered. A Grade "3" leak is a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Grade "1" , Grade "2 Priority" and Grade "2" leaks must be reported to the DOT, however Grade "3" leaks are typically not reported to the DOT in the annual DOT 7100 system reports.

Q Please discuss Columbia's emergency response performance.

A. Even with Columbia's large geographic service territory, our emergency response efforts continue to be strong. Columbia has steadily improved our emergency response time over the last several years. We measure this by tracking the percentage of emergency, or priority, calls we respond to in less than 1 hour. In 2001 Columbia responded to these types of calls in less than sixty minutes 94.63% of the time, and has steadily improved to responding 97.18% of the time within sixty minutes in 2007. Columbia has maintained its commitment to ensure a safe and reliable system for its customers.

V. Rider IRP

A. Overview of Rider IRP

Q. What is Rider IRP and define what program components are included in it?

A. Rider IRP is essentially an infrastructure tracker which captures cumulative plant investment over a specified period of time and provides for a return on and the return of all program costs. The program components that make up the IRP are: (1) the AMRP; (2) the replacement program for prone to failure risers, and assumption of installation, maintenance, repair and replacement of customer service lines; and, (3) the AMRD program. Larry Martin is providing additional testimony for the financial structure of Rider IRP. Brad Bohrer is providing testimony for the support of the AMRD program component of Rider IRP.

B. Accelerated Main Replacement Program ("AMRP")

Q. Provide a brief overview of Columbia's Proposed AMRP.

A. A significant percentage of Columbia's gas distribution main is reaching the end of its useful life. In order to continue to provide safe, reliable delivery of gas service, Columbia has positioned itself to accelerate the replacement of certain types of gas main and services. The type of mains and services Columbia is proposing to replace is unprotected bare steel, cathodically protected bare steel, un-protected coated steel, wrought iron, and cast iron. Columbia considers these types of gas distribution main, ("Priority Pipe" or "Priority Main"). Columbia is proposing to replace these mains and associated metallic services over the span of twenty five (25) years. Columbia has estimated that the average annual cost of this program will be approximately $73 million. Included in this estimate is the replacement cost of the mains, service lines, risers, meter move-out costs, and all associated appurtenances.

Q. Why does Columbia need an AMRP?

A. Columbia's distribution system consists of approximately 4,000 miles of Priority Pipe, which is continuously subjected to corrosion and ground movement. Over half of this pipe was installed prior to 1940, while the remainder was installed between 1940 and 1970. Columbia's bare steel and unprotected coated steel mains are at a point in their useful life where some areas have began corroding in an accelerated manner. Columbia also believes its cast and wrought iron mains are also near the end of their useful life and that additional subjection to ground movement could cause significant leakage of natural gas. Beginning the AMRP in 2009 will reasonably allow Columbia to replace its highest risk pipe. This program will significantly improve safety and reliability of service for our customers.

Q. You mention unprotected steel, wrought iron, and cast iron main. Describe the various types of pipe that make up the Columbia gas distribution system.

A. Columbia's gas distribution system is comprised of many different types of pipe. From the late 1800's to the 1950's, Columbia, its predecessor companies and the rest of the gas industry primarily installed pipe made of cast iron, wrought iron and unprotected bare steel. Columbia continued to install unprotected bare steel in the 1950's and into the 60's, but also began to install some unprotected coated steel pipe in the late 50's to late 60's. In the late 60's and early 70's Columbia began installing cathodically protected coated steel and plastic pipe. These last two types of pipe are the primary types of pipe still being used today. Attachment DAR-1 shows a breakdown of Columbia's gas distribution system by material type in miles of pipe for main lines, and the number of services for each material type.

Q. Discuss the use of cast iron and describe the problems associated with using it for natural gas distribution pipe.

A. Cast iron was among the first material available, and was the pipe of choice in the late 1800s and early 1900s. Cast iron was relatively strong and easy to install. However, it is susceptible to cracks when pressure is exerted on the pipe and is also vulnerable to breakage from ground movement. Further, cast iron pipe utilized the bell and spigot joint method to join each section of pipe. This joining method is more prone to leakage since any ground movement can readily cause cracks to develop in the sealing materials. Finally, it was determined that cast iron pipe was unsuitable for long-distance transportation of gas because it was unable to withstand high pressures.

Q. How did the industry react to the problems associated with the use of cast iron?

A. By the 1920's, the industry had adopted unprotected bare steel and wrought iron piping for mains. This type of pipe was deemed to be stronger than cast iron and able to withstand greater pressure. During this time, unprotected bare steel and wrought iron began replacing cast iron pipe as the material of choice for building a natural gas distribution system. After World War II, Columbia installed a significant amount of unprotected bare steel mains and services. Unprotected bare steel is steel pipe that has no exterior coating.

The use of unprotected bare steel and wrought iron was common until the 1950's and 1960's when the industry began to realize that despite its strength, bare steel was subject to ongoing deterioration of pipe wall from galvanic corrosion.

Q. Are there any additional safety and reliability risks associated with the use of unprotected bare steel, wrought iron, and cast iron?

A. Yes, unprotected bare steel pipe is subject to galvanic corrosion, which reduces the wall thickness and increases the risk of leakage or fracture. Wrought iron also corrodes similar to steel, but not at such a high rate. An example depicting the corrosion rates of steel and wrought iron is shown on page 20 of Black & Veatch's Attachment SV-1. However, wrought iron is more susceptible to leaks due to ground shifts. Cast iron mains are susceptible to cracking and leakage at the joints due to surface conditions such as; traffic, soil subsidence, movement in the soil from freezing or drought conditions, and construction activity. Unprotected bare steel, wrought iron, and cast iron are subject to leaks at a greater rate than cathodically protected coated steel and plastic mains. Pipe of this type, which is more likely to leak, can lead to safety and reliability risks, and higher operating and maintenance expenses.

Q. Explain the process of corrosion.

A. Galvanic corrosion is a natural electro chemical reaction that is responsible for the majority of corrosion, loss of pipe wall, and leakage in underground steel piping systems. Galvanic corrosion occurs when dissimilar metallic materials are connected electrically and exposed to an electrolyte. The following fundamental requirements have to be met for galvanic corrosion to occur:

1. Dissimilar metals (metal surfaces with different electrical potentials);

2. An electrical contact between the metal surfaces with dissimilar electrical potentials; and,

3. Both surfaces must be in contact with an electrolyte (a non metallic conductor of electricity such as soil).

It is the electrical potential difference in the metals that is the driving force for galvanic corrosion. The less noble material in the galvanic couple will become the anode and tend to undergo accelerated corrosion, while the more noble material (acting as a cathode) will not experience corrosion effects.

The requirements for galvanic corrosion to occur exist on all buried steel pipelines. Electrical potential differences exist between the surfaces of individual joints of steel and can exist on the same section of pipe due to a variety of factors such as handling, manufacturing inconsistencies, and joining techniques. Additionally other metals having varying electrical potential are necessary to build a pipeline such as joint couplings, welding rod steel, and tap fittings. All underground pipelines are surrounded by soil which is an electrolyte. Because all the requirements exist in buried pipelines, galvanic corrosion starts as soon as the newly constructed pipeline is backfilled and continues without interruption until anodic areas of the pipeline are consumed by the process. The speed at which this process takes place is controlled by a number of factors; the relationship in size of anodic areas to cathodic areas along the pipeline; the magnitude of difference in the electrical potential of metals used to build the main; and the electrical resistance of the electrolyte (or soil) in contact with the surfaces of the pipeline. Columbia's first generation of steel piping systems, unprotected bare steel, have been continuously subjected to the deteriorating effects of galvanic corrosion since installation in the early 1900's.

Q. What did the industry do to combat the problem of corrosion in unprotected bare steel?

A. Natural gas distribution companies began using coated steel. Coated steel refers to steel pipe with an exterior dielectric coating. The coating is intended to electrically isolate the steel from the surrounding soil (electrolyte). Effectively isolating the steel from the surrounding soil eliminates one of the requirements for galvanic corrosion to take place.

Q. Did the use of coated steel solve the problem?

A. No. Despite the best efforts of industry to produce a perfect coating, coated steel corrodes anywhere there is a flaw in the coating, allowing the soil to come in contact with a bare steel surface on the pipeline. However, for the period from the 1950's through the 1960's, coated steel was the best alternative piping material available to meet the public demand for service. By the early 1970's, Columbia had laid its last non-cathodically protected coated steel segment.

Q. What material replaced unprotected bare steel and unprotected coated steel as the material of choice for gas distribution systems?

A. Coated steel continued to be used, but the coating was supplemented with cathodic protection.

Q. What is "cathodic protection?"

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion (loss of pipe wall) by applying a direct electrical current to the bare surface of the pipe. Cathodic protection reduces corrosion by making the uncoated surface of the pipe the cathode, and another metal the anode of a galvanic cell. The primary function of a pipeline coating is to electronically isolate the pipe surface from the soil. No coating is perfect, so in effect the coating minimizes the bare steel surface area that is in contact with the soil. Cathodic protection can be achieved by applying as little as 1 milli-amp of current per square foot of bare steel surface area. Minimizing the bare steel surface area of a pipeline in contact with the soil through the use of coatings minimizes the current necessary to protect the pipeline from galvanic corrosion. At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection.

Q. Has the industry further improved the functionality of its piping since the introduction of cathodically protected coated steel?

A. Yes, it has. The major advancements have been in development of better pipeline coatings and joint coatings. Coatings are now available with better adhesion to the pipe, more durability in the underground environment, and better handling capabilities. Joint coatings have improved in the same areas, and the application processes have significantly improved. Cathodically-protected coated steel has all the advantages of steel in terms of strength, and because of its impressed electrical current, is highly corrosion resistant. However, cathodically protected coated steel is more costly to purchase, install, and maintain than the next generation of gas distribution pipe, which is plastic or polyethylene.

Q. What are the benefits of plastic pipe?

A. Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic pipe is also less costly to purchase and easier to join and install than steel pipe. Another significant benefit is that plastic does not corrode; and therefore does not require cathodic protection.

Q. Does plastic pipe have any drawbacks?

A. One significant drawback to plastic is its relative vulnerability to third party damage compared to cast iron or steel. Cast iron and steel piping have greater tensile strength and a greater resistance to external impact. As a result, excavators who do not dig by hand in the vicinity of plastic facilities are more likely to damage plastic pipe.

Q. Please describe the manner in which Columbia has been addressing the replacement of its Priority Pipe.

A. Columbia has continuously replaced Priority Pipe in its system since the late 1960's and early 1970's. Columbia currently replaces pipe segments following an analysis of the segment's historical leak rate, along with a number of other internally defined risk criteria. Columbia attempts to identify the likely worst performing segments and replaces those each year. Columbia also replaces short segments of pipe on an emergency basis when it is determined that an effective repair cannot be made.

Q. Why is Columbia now so concerned with its Priority Pipe that it has decided to address this issue within this proceeding?

A. As stated earlier, Columbia has approximately 4,000 miles of Priority Pipe remaining in its system along with over 170,000 unprotected bare steel service lines. This pipe has been exposed to the effects of galvanic corrosion since its installation. In spite of Columbia's operational practices, Columbia is averaging over 2,900 corrosion leaks per year on its mains over the past five years. In addition, Columbia has seen a rise in the number of emergency replacements of short sections of pipe. Because of these factors and others stated earlier, it is in the best interest of Columbia's customers to initiate a planned and efficient replacement program for the remaining inventory of Priority Pipe.

Q. How do you know that the cause of these leaks is corrosion?

A. Columbia trains its field technicians to identify corrosion conditions whenever a main or service line is exposed and report these conditions on a leak report and main exposure forms. While other causes can create leaks, such as third party damage, outside forces (frost, traffic loads), construction defect (damage on pipe during installation), or material defect (faulty manufacturing), I have examined Columbia's leak history by type and have calculated that more than 74 percent of all main leaks are the result of corrosion on unprotected bare steel mains. Testimony submitted by Steven Vitale of Black & Veatch provides a detailed analysis of Columbia's leak and corrosion data in comparison with other gas distribution companies.

Q. If corrosion leaks were to increase in the future, does this increase the risk to public safety?

A. Yes. Every corrosion leak has the potential to become a risk to public safety, and because the unprotected bare steel mains are getting older and the corrosion process is continuous, the risk of an incident occurring is increasing.

Q. Does corrosion render Columbia's system unsafe?

A. No. The system is safe right now as evidenced by Columbia's ability to address all Grade "1," Grade "2 Priority" and Grade "2" leaks in accordance with its O&M plan. The system is comprised of approximately 4,000 of miles of Priority Pipe with another 15,000 plus miles of cathodically-protected coated steel, and plastic pipe. While the system is currently safe, Columbia must, as a prudent, safety-conscious operator, address its Priority Pipe before the corrosion of pipes significantly impacts safety and reliability. This is why Columbia is implementing the AMRP now.

Q. Is replacement the only remedy? Is there any other way to retard or arrest the corrosion problem inherent in unprotected bare steel?

A. In theory, a cathodic protection current could be applied to the surface of a bare steel piping system to protect it from galvanic corrosion. In practice, however, cathodic protection of bare steel systems is not a practical approach. Since the amount of direct current that must be applied to a bare steel surface to achieve protection is directly proportional to the surface area of the steel being protected, current requirements for a bare steel system are very high compared to the current requirements of a coated steel system. Introduction of high levels of direct current into the soil in urban areas often results in damage to other underground metal structures such as water systems, underground tanks, and metal shielded cable systems, through a process called stray current corrosion. Even if cathodic protection were a possibility to mitigate the ongoing deterioration caused by galvanic corrosion, there is no process that could reverse or replace the damage that has already occurred on a bare steel system.

Q. If replacement is necessary, what has Columbia done to prepare for such a large replacement program?

A. In anticipation of the need for an AMRP, Columbia has been ramping up its capital replacement program for the last year and a half. Columbia has also been evaluating internal resource needs, external resources, construction practices, computer applications and analysis tools, communication strategies, leveraging economies of scale for materials, and developing program goals.

Q. How has Columbia ramped up its capital program for the AMRP?

A. In 2007, specific replacement projects were identified; planned, designed, and constructed that was of similar scope and magnitude as those anticipated for the AMRP. This allowed Columbia to not only retire some old leaking gas mains, but also observe and learn what it can expect to happen with future projects. For 2008, Columbia has increased its capital replacement program by approximately $20 million over what was planned in 2007. Columbia is planning on spending approximately $73 million in 2009 for its capital replacement program. The 2009 capital replacement program would be considered the first full year of the AMRP.

Q. What was Columbia's outcome in evaluating their internal resources?

A. In 2006 and 2007, several of Columbia's departments, including Operations, Construction, and Engineering, evaluated their staffing needs and added to compliment where necessary and as appropriate. Most of the staffing additions were strategically located in areas to support the AMRP. Columbia will continually review their staffing needs to ensure proper support of the AMRP.

Q. What engineering design and construction method of replacement is the most efficient and cost-effective for the AMRP?

A. The most cost effective method of replacement is an area-based replacement strategy. The area-based replacement strategy employs a systematic approach rather than a segmental replacement approach which targets discrete areas, neighborhood-by-neighborhood, and block-by-block, in a geographically continuous fashion. The AMRP will be efficient because construction crews can stage work continuously by shifting the worksite along the pipe being replaced, day in and day out, rather than what is often the case now where crews open and close worksites and relocate labor and equipment across town or across the service territory. In addition, there are the public benefits of minimizing disruptions in traffic flow by concentrating work in one section of a municipality.

Q. How will Columbia try to ensure the expected efficiencies and reductions in construction costs?

A. The AMRP will replace all Priority Pipe, metallic services, and all associated appurtenances, as well as, move inside meters outside throughout Columbia's service territory. When planning each project Engineering will evaluate the capacity requirements of its customers and the most reasonable routing of infrastructure to serve them. Replacement projects will be identified and selected based on risk assessment; the condition and age of the pipe; geographical proximity; the capacity needs of the area; and, expected growth in system demand requirements. Efficiencies will be maximized and costs minimized by addressing large segments of the system for replacement on a planned, systematic basis. By identifying large segments of the system that require attention, Columbia can focus resources and complete full segment replacements in an orderly and predictable fashion.

Q. What materials will be used for the newly installed mains?

A. The replacement mains and services are expected to be plastic or cathodically protected coated steel throughout the system.

Q. Are there any new computer applications or analysis tools that Columbia has decided to purchase to assist with the AMRP?

A. Yes. Columbia is in the final stages of implementing a new geographic information system ("GIS") for all of Ohio. This tool will significantly decrease the design time across the board. Once GIS is available, our Engineering department is planning on having gas distribution models built for all systems that do not have them. The models and associated tools assist engineers in evaluating the performance of a system. Pipe size and pressure recommendations can be made much more efficiently with these tools. Lastly, Columbia has purchased and will be utilizing Optimain DS™ to evaluate and rank pipe segments system-wide against a range of environmental conditions, risks, and economic factors.[1] Optimain DS™ will be used to assist in developing and prioritizing the replacement projects.

Q. How will the AMRP affect leak repair?

A. Columbia anticipates a significant reduction in leakage and associated operations and maintenance expenses over the duration of the proposed AMRP. As stated earlier, more than seventy percent of our leaks are due to corrosion on unprotected bare steel mains. Initially, Columbia will prioritize areas and pipe segments of its worst performing pipe. The new applications and tools mentioned earlier will assist us with this, as well as, help maintain objectivity. The elimination of leaking pipe, and thus risks, will be the largest benefit for our customers.

[1] Optimain is the industry's leading comprehensive decision support solution for predictive failure analysis and risk assessment.

Q. When developing the AMRP, were alternatively defined lengths of the program considered, and why was a twenty five year period selected?

A. Various program lengths were evaluated, but the duration of twenty five years was chosen because it best matched the combination of risk (the safe and reliable delivery of natural gas) and resource needs (internal/external labor, material, capital, etc.). Although Columbia believes the Priority Pipe and metallic services should be replaced as expediently as possible, internal and external resource constraints have driven us to choose twenty five years as the most reasonable program duration. Customer and municipal impacts were also taken into account in this decision. Columbia will continually monitor and evaluate the program to ensure safe and reliable delivery of service.

Q. What assumptions are behind the cost estimate of $73 million per year?

A. As I mentioned earlier, this dollar estimate captures all of the AMRP's assumed costs, including the retirement of approximately 160 miles of Priority Pipe each year and associated metallic service lines. The program also includes costs to relocate affected meters and associated appurtenances to an outside location if necessary. Certain cost efficiencies are also assumed in design and construction due to advantages of project scale.

Q. What are the benefits of the AMRP, compared with Columbia's historical replacement program?

A. For municipalities and state highway departments, the AMRP provides a systematic and predictable schedule of construction activities and minimizes disruption to traffic, roads and highways. Greater continuity of service is also assured rather than if the program were administered on an emergency basis.

Q. What are the economic benefits of the AMRP?

A. By commencing a systematic geographic approach to replacement that integrates Columbia AMRP work with state and municipal improvements, costs will be minimized. A systematic replacement approach produces efficiency gains allowing more main to be replaced for the same price. Columbia will also be able to work through its pipeline supplier to purchase larger quantities of construction materials, resulting in lower costs. Columbia expects O&M expenses to decline over time by reducing problematic pipe having corrosion leaks.

Q. What are the economic development benefits of the AMRP?

A. A possible benefit of the AMRP is the potential for improving economic development for many communities. Columbia plans to eliminate many low pressure systems currently in service which significantly limits the size of the load that can be added. By installing new mains that operate at a higher pressure, Columbia could potentially serve larger loads than the current low pressure systems. The Engineering department will also be evaluating the current and future needs of the areas where replacement will occur and ensure adequate sizing of infrastructure to meet those needs.

Q. How does the customer benefit from Columbia's AMRP?

A. Columbia will replace deteriorating pipe and enhance the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Its system will continue to be able to provide deliverability at its Maximum Allowable Operating Pressure. The public will receive safe and reliable delivery of service with fewer unscheduled interruptions. Also, many of the service lines Columbia will be replacing are quite old. Large portions of these lines would typically be replaced by the customer. Under this program, Columbia will be replacing the lines at no cost to the customer. Lastly, Columbia will be moving, whenever possible, meters that are inside a customer dwelling to the outside. This will save customers from having to let a meter reader into their homes, which we know is an inconvenience for working families.

VI. Assumption of Installation, Maintenance, Repair and Replacement of Customer Owned Service Lines and Replacement of Prone to Failure Risers

A. Customer Owned Service Lines

Q. What is a customer service line?

A. A customer service line is defined as the pipe from the outlet of the curb valve, or property line, up to and including the meter connection.

Q. Does Columbia currently own customer service lines?

A. No. Columbia's current tariff provides that the customers own their own service lines. The customer is responsible for all installation, maintenance, repair, and replacement costs associated with customer service lines. Columbia owns, and is responsible for repairs and maintenance of the service line from the tap at the gas main to the curb valve or property line. Ohio is one of the few states in the country where the customers own their customer service lines and are responsible for all required installation, maintenance, repair, and replacement costs.

Q. What responsibilities has Columbia requested with regards to customer service lines?

A. Columbia is requesting approval to assume financial responsibility for all future maintenance, repair, and replacement costs of existing customer service lines. Columbia also proposes to assume financial responsibility for the installation of new customer services lines. Columbia would be responsible for installing and maintaining these service lines. Lastly, Columbia proposes to assume ownership of any future customer service line constructed or installed by Columbia, and requests the accounting authority as may be required to permit capitalization of Columbia's investment in the customer service lines.

Q. How would customers benefit from Columbia's proposal to assume financial responsibility of customer service lines?

A. There are several ways Columbia's customers' would benefit from this proposal:

1. The customer would no longer have to pay the up-front expense of installing a customer service line for a new structure.
2. The customer would no longer be responsible for repair costs over the life of the customer service line.

3. The customer would no longer have to pay to replace the service line once it reached the end of its useful life. Customers owning existing customer service lines would benefit from points 2 and 3.

4. Customers' will have a single point of contact for all concerns about customer service lines.

5. Customer confusion about who is responsible for what types of repairs will virtually be eliminated. Columbia will be responsible for any necessary repair or replacement of customer service lines.

6. Customers' will not have to make decisions about the repair or replacement of customer service lines for which they have limited knowledge. Customers' typically have limited knowledge on the relative costs of repairing or replacing a service line, the quality of the plumbers' work for who they call, or the materials necessary to effectuate such repairs or replacements.

7. Customers' will be provided timely restoration of gas service when service has been disrupted to complete repairs or replacements of customer service lines. Columbia is proposing restoration of gas service within three working days in the non-heating season and by the end of the next day during heating season.

<u>B. Risers</u>

Q: What is a natural gas riser?

A: A natural gas riser is the vertical portion of a customer service line that connects the balance of the customer service line to the meter settings.

Q: Why have risers become an issue in this and other regulatory proceedings?

A: Since 2000, there have been four "incidents", as that term is defined by Ohio Administrative Code Rule 4901:1-16-02(J)(3), related to natural gas risers. These events led the Commission to initiate a Commission-ordered investigation in Case No. 05-463-GA-COI. In various entries issued in that docket the Commission directed the state's four large Local Distribution Companies ("LDCs"), including Columbia, to identify a sample number of installed risers, and to remove a number of risers for submission to a testing laboratory selected by the Commission. After testing was completed the Commission staff filed its Staff Report of Investigation in Case No. 05-463-GA-COI. The Staff Report found that failures of natural gas risers present a significant public safety hazard and because these failures can not be predicted the Staff recommended that all risers identified as prone to failure should be replaced. The Staff also recommended that LDCs conduct a riser inventory of their system so that they would have knowledge of the types and locations of risers in their systems. Columbia subsequently initiated a riser identification survey, and as of February 20, 2008, has completed 99.3% of the survey and estimates that the survey will identify approximately 320,000 prone to failure risers and 17,600 leaks on customer service lines, risers and meter settings within its service territory.

Q: What is Columbia requesting?

A: With the knowledge of the estimated number of prone to failure risers within its service territory, the potential magnitude of the costs, and their resulting impact upon individual customers, Columbia believes that the best solution would be for the Company to assume responsibility for the orderly and systematic replacement, over a period of approximately three years, of all Design-A risers that are prone to failure if not properly assembled and installed.

Columbia cannot, however, commit to undertake such a program, and to raise the significant amounts of incremental capital required to assume these obligations of the customer, without some type of accelerated cost recovery.

Q: What is Columbia's plan to replace prone to failure risers?

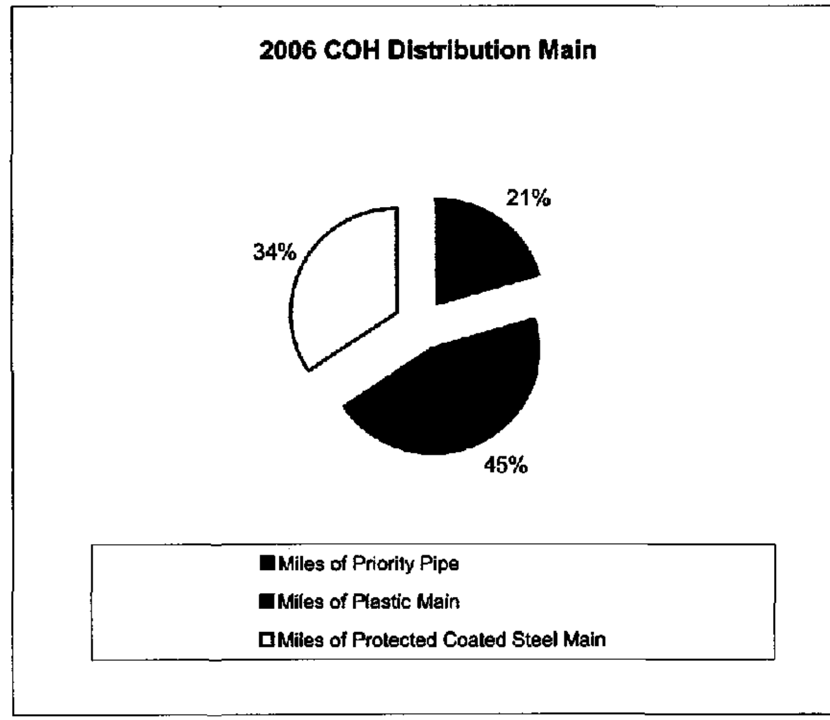
A: Columbia is proposing an orderly and systematic replacement, over a period of approximately three years, of all Design A risers that have been identified as prone to failure. Columbia estimates that the project will replace approximately 320,000 natural gas risers at an estimated cost of $160 million dollars.

VII. CONCLUSION

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, it does.

Columbia Gas of Ohio's Infrastructure Breakdown (2006 DOT Reported Data)		
Miles of Unprotected Bare Steel Main	3,663	"Priority Pipe"
Miles of Unprotected Coated Steel Main	52	"Priority Pipe"
Miles of Protected Bare Steel Main	52	"Priority Pipe"
Miles of Protected Coated Steel Main	6,735	
Miles of Plastic Main	8,806	
Miles of Cast/Wrought Iron Main	280	"Priority Pipe"
Miles of Other Main	3	
Total Miles: Distribution Main	**19,591**	
No. of Unprotected Bare Steel Services	171,589	
No. of Unprotected Coated Steel Services	2,413	
No. of Protected Bare Steel Services	2,431	
No. of Protected Coated Steel Services	315,119	
No. of Plastic Services	842,348	
Total Number of Distribution Services	**1,333,900**	



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

PREPARED DIRECT TESTIMONY OF
JOHN E. SKIRTICH
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

☐ **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**

☐ **OPERATING INCOME**

☒ **RATE BASE**

☐ **ALLOCATIONS**

☐ **RATE OF RETURN**

☐ **RATES AND TARIFFS**

☐ **OTHER**

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March 17, 2008

PREPARED DIRECT TESTIMONY OF JOHN E. SKIRTICH

Q: Please state your name and business address.

A. My name is John E. Skirtich. My business address is 211 West Washington St. Suite 2410, South Bend, Indiana 46601.

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

A. I am associated with Adecco Technical.

Q. Please describe your professional experience.

A. During 1970, I worked for R. A. Saunders and Co., a CPA firm in Columbus, Ohio as an accountant. In November 1970, I was hired by the Columbia Energy Group Service Corporation as a Tax Accountant. Subsequent assignments in that location included General Accountant, Senior Management Accountant, and Senior Analyst. In September 1982, I was transferred to work for the Columbia Energy Group gas distribution companies as a Financial Analyst in the Rate Department. In March 1986, I was promoted to Senior Rate Engineer, and in March 1991, to Manager of Regulatory Planning. On June 1, 1993, I was promoted to Director of Regulatory Support Services, and on November 1, 1993, to Director of Regulatory Policy and Planning. I was named Function Leader for Shared Services - Finance and Regulatory of the distribution companies of Columbia Energy Group on November 1, 1996, in which role I continued until mid-2000.

In June 2000, I retired from Columbia Energy Group. In December 2000, I began providing regulatory consulting services for several distribution companies of NiSource Inc. Acloché LLC, an employment service, hired me as a regulatory consultant in June 2001, and

I continued to provide regulatory services for NiSource Inc. In 2005, Adecco Technical, a division of The Adecco Group, an employee service company secured the contract to provide all temporary employment services for NiSource, Inc. In March 2005, I transitioned to Adecco Technical where I continue to provide regulatory consulting support to NiSource Inc.

Q. Please describe your educational background.

A. I graduated from Capital University, Columbus, Ohio, in 1970, with a Bachelor of Science degree in Business Administration.

Q. Have you ever testified before the Public Utilities Commission of Ohio or any other regulatory commission?

A. I have not testified before the Public Utilities Commission of Ohio ("PUCO"), but my testimony has been accepted by the Pennsylvania Public Utility Commission, Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission and the Virginia State Corporation Commission.

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

A. I have been asked by Columbia Gas of Ohio, Inc. ("Columbia" or "the Company") to prepare and present a Lead-lag study in support of Columbia's cash working capital claim. The study is presented in Schedule B-5, pages 2 through 19 with the summary results shown on page 1 along with other working capital items.

Q. Briefly define Cash Working Capital and describe the lead-lag method of determining Cash Working Capital for rate making purposes.

A. The commonly used and accepted definition of working capital is "a measure of liquidity computed by subtracting current liabilities from current assets." Working capital, as it applies to a regulated utility and to rate base, is a value assigned to assets which are current or short-term in nature. The value of these current assets represents a need for invested funds. Cash Working Capital ("CWC") is that portion of working capital that is needed to finance the time period between receipt of payment of utility service and the disbursements required to render that service.

"Revenue lag," the time period from the date that customers receive service to the date that the Company receives payment from customers for service, is the basis for determining the annual cash requirement that must be financed by the Company. This cash requirement is offset, in part, to the extent that Columbia experiences delays in payments for labor, materials and supplies, and other expenses incurred in providing service to customers. These offsets are defined as "expense leads." Negative expense leads represent prepaid expenses and have the same outcome as the revenue lags because they require additional CWC to be provided by the Company's investors. The examination of the timing of these fundamental cash transactions constitutes the lead-lag method of determining CWC.

Q. Please describe your Lead-lag study and how it is used in determining Columbia's CWC claim as presented on Schedules B-5.

A. The Lead-lag study was prepared using actual data for the twelve months ended September 30, 2007. Revenue lag and expense lead days were developed from this data and are presented in pages 2 through 19 of Schedule B-5. Mr. Martin, provided the cost levels for the appropriate cash working capital categories of his cost of service which I then applied to the revenue and expense days to arrive at the Company's CWC claim as shown on Schedule B-5, page 1.

Q. Please explain how the revenue lag days were determined.

A. The revenue lag of 42.44 days, Column 6, page 1, is summarized on page 2. The revenue lag is comprised of a 15.2 day "meter reading" period plus a 24.92 day collection lag and a 2.32 day billing lag.

Columbia reads (actual or estimated) most of its meters on a monthly cycle basis with the time between meter reading dates averaging 30.4 days (365 divided by 12). Because service is provided throughout the month, the average lag from the time service is rendered until the meters are read is 15.2 days (30.4 divided by 2).

The collection lag, calculated on page 3, represents the time from the date bills are rendered to the date cash is received in payment of the customer's bill. This lag was arrived at through examination of accounts receivable balances for all sales and transportation accounts using the accounts receivable turnover method. End-of-month book balances were utilized as the most accurate measure of customer accounts receivable. Under the accounts receivable turnover method, the twelve month-end balances of Accounts Receivable were averaged to calculate the Average Accounts Receivable Balance of $144,148,284 as listed on page 4b. "As billed" per book revenue were divided by 365 days to calculate the Average Daily Revenue amount of $5,784,512. The collection lag of 24.92 days as shown on line 18 was arrived at by dividing the average daily accounts receivable by the average daily revenue.

The 2.32 day billing lag represents the average processing time after service is rendered and meters are read which is required to enter data into the billing system, compute, print, place in envelopes, sort and mail monthly statements. Columbia has three billing systems to match the unique meter reading and billing characteristics of its customers. The Distributive Information System ("DIS") bills sales and transportation customers that do not have any unique requirements. Meters are read with the data processed and billed that evening and mailed the next day. As shown on page 5, Line 1, the billing lag for these customers is assumed to be 1 day. Customers that have special meter reading equipment and /or needs under their tariff are billed through the Gas Transportation System or Gas Accounting System. Additional processing time is required for these two groups of customers. For example, many of the larger customers require daily consumption data. Meter charts are provided showing the daily pressure, temperature and consumption levels which then must be loaded, confirmed and converted into an adjusted volume amount for billing. This activity is more labor intensive than the small general service type customer group. For general transportation service, customer gas is delivered to Columbia on a calendar basis while their meters are read on a cycle basis. Billing is held up until the end of the month to ensure adequate supplies have been delivered. The time from meter read to bill were separately measured for these customers. The billing lags are shown on Lines 2 and 3, Column 3. The three groups were then weighted based on the revenue billed to arrive at an overall average of 2.32 days shown on Line 4, Column 3.

Q. How were the expense lead days for gas purchases determined?

A. Columbia purchases gas from various producers and transports it through interstate pipeline companies. For each service month, the number of days from the midpoint of service to the payment date for gas received was determined from Columbia's accounts payable system. The gas purchase expense lead days are calculated by dividing the annual weighted dollar lead days by the annual amount paid to the suppliers. On page 6, the costs for all the suppliers were totaled and averaged to establish an overall weighted average of 40.17 lead days for gas purchased. Twelve months of purchases were considered in developing the purchase expense lead.

Q. Were all the various types of payroll used to determine the number of lead days for payroll?

A. Yes. Turning to page 7 of the Lead-lag study, bi-weekly, weekly and monthly payrolls were used to measure the payroll lead days. For bi-weekly payroll, the pay period ends on Saturday, but employees are paid on Friday, or one day before the pay period ends. The weekly payroll period ends on Sunday and employees are paid on the following Friday. The monthly payroll period ends on the last day of the month, and pay day is also on the last day of the month. When a normal pay day ends on a holiday or weekend for monthly employees, pay day falls on the previous business day. Lead days were calculated from the midpoint of the pay period to pay day arriving at an average lead of 6 days for bi-weekly, 8.5 days for weekly, and 14.68 days for monthly. The three lead days were weighted based on payroll as shown at the bottom of page 7 resulting in an overall payroll lead of 8.15 days. Due to payroll size, NiSource Inc. is required to make its tax withholding payments on the same day employees are paid, therefore, the lead days for withholding of taxes are the same as net pay.

Q. Please explain how you handled Columbia's major benefit costs in your Lead-lag analysis.

A. Regarding the Company's post retirement benefits other than pensions ("OPEB") cost, Columbia accounting is consistent with the Commission policy (See Case No. 92-1751-AU-COI issued 2/25/1993) recognizing such costs in accordance with Financial Accounting Standard No. 106. The Company funds monthly the expense level determined under this standard. OPEB funding occurs via a convenience bill from NiSource Corporate Services Company ("Corporate Services"), and the expense lead days of 44.00 days are calculated on page 8. The other major benefits are paid by Columbia on a monthly basis also via the Corporate Services convenience bill. The date of the convenience bill was compared to the midpoint of the service month. The convenience bill is processed near the end of the service month for an overall expense lead of 12.70 days for the other benefits as detailed on page 9.

Q. How were the Corporate Services lead days of 43.12 on page 10 determined?

A. Columbia pays monthly for the services provided on a contract basis by Corporate Services. Generally, payment is made at the end of the month following the month service was provided. The date paid was compared to the month in which the related services were provided, and resulted in an overall expense lead of 43.12 days for the test year.

Q. Why are expense lead days shown for corporate insurance negative?

A. Corporate insurance costs are paid in advance of services provided reflecting a working capital requirement. As indicated on page 11, payments are made well in advance of the corresponding service period resulting in a negative 153.15 expense lead. Furthermore, Columbia's books and records recognize a prepayment of these costs.

Q. How are expense lead days determined for uncollectibles and PIPP uncollectibles?

A. The revenue lag days of 42.44 was assigned to uncollectibles and PIPP uncollectibles. By assigning the revenue lag days to these cost categories virtually eliminates the associated cash working capital from base rate development. This treatment is consistent with the Commission's precedent in handling uncollectibles for cash working capital purposes.

Q. What is included in other operation and maintenance expense (line 11 on page 1) and how was the 23.25 day expense lead on page 12 determined?

A. Payments to a wide variety of vendors for all O & M costs, other than those already mentioned (payroll, benefits, gas purchased and uncollectibles) are included. These include items such as outside services, office supplies, and employee travel expenses. Payments are made through several payable systems with most, over 85%, being paid through the accounts payable system and the work management system. Since most of the payments are made through these two systems, separate lead days were calculated and then combined to arrive at an overall average for this category of expense. For the accounts payable system, 400 invoices were randomly chosen. Each invoice was reviewed to determine the service period of the O & M expense. The payment date is readily available as part of the accounts payable system. The lead days between the payment date and the midpoint of the service period were calculated. The lead days were dollar weighted to arrive at an overall dollar weighted expense lead of 30.36 days.

For the work management system, all of the 8,149 purchase orders were used to calculate the lead days between the purchase order date and the check date. The lead days were dollar weighted to arrive at an overall dollar weighted expense lead of 9.67 days. The lead days for the above O & M costs were further dollar weighted to calculate a total lead of 23.25 days as summarized on page 12.

Q. How was the expense lead days for payroll taxes calculated?

A. Similarly with the other expense items, the tax payments were compared to their respective service or tax period. Columbia deposits its FICA tax liability the same day as pay day. Federal and state unemployment taxes are paid quarterly until the liability is no longer applicable. The lead days between the deposit date and the midpoint of the pay periods were calculated for all the deposits and were dollar weighted to arrive at an overall expense lead of 8.63 lead days as detailed on page 13.

Q. How did you develop the expense lead days for property taxes?

A. Columbia makes semiannual payments to all the counties in which it owns property; both real and personal. The tax is for the calendar year with the semiannual payments generally made in the first and third quarter of the following year. In developing the expense lead days of 284.77 days as shown on page 14, the semiannual payments made during the test year were compared to the respective tax years. The lead days were dollar weighted to arrive at an overall dollar weighted expense lead of 284.77 days.

Q. Please explain how you determined the expense lead days for Ohio regulatory fees?

A. The schedule is set forth on page 15 and shows an expense lead of 32.31 days for PUCO and OCC Maintenance fees and 26.88 days for DOE and Pipeline Safety fees. The days were based on the actual payment made during the twelve months ended September 30, 2007.

Q. How are payments for distribution excise and gross receipts taxes reflected in the lead-lag study?

A. The various tax expense leads were based on the corresponding statutory requirement regarding their payment. In order to determine the lead days, the mid-point of the applicable service period was identified and compared to the required payment date. Then weighting the tax dollar payments, expense lead days were calculated for Distribution Excise and Gross Receipts of 87.60 and 90.80 days, respectively. The detailed calculation of lead days is shown on page 16.

Q. What taxes are reflected in the sales and uses tax category and how was the expense lead days developed?

A. The sales and use tax is comprised of two cost components; direct payment sales tax and sales and use tax. Most of the cost is from direct payment sales tax. The expense lead days for both Columbia's sales and use tax categories were calculated using the actual taxes paid top the state of Ohio. The overall average expense lead is shown on page 17 and totals 38.20 days.

Q. Do Federal Income Taxes - Current follow a schedule prescribed by the IRS?

A. Yes. Starting in 1996, federal tax law requires 100% of the current year estimated tax liability to be paid in four equal installments dated April 15, June 15, September 15 and December 15. The lead days of 37.50, as shown on page 18, were based on this schedule.

Q. Why are there no lead days for post-1970 investment tax credits?

A. Regarding the investment tax credit, to assign lead days would be to flow tax credit benefits through to ratepayers in a manner other than that permitted by the normalization requirements of the Internal Revenue Service.

Q. How were the lead days associated with interest on debt calculated?

A. Interest expense on long term debt was assigned expense lead days based on the semi-annual payments of Columbia's installment promissory notes. Page 19 shows the calculation of the long term debt interest expense lead days of 91.25.

Q. Please summarize your lead lag study and its results.

A. The revenue lag and expense lead days were developed using generally acceptable lead lag techniques and produced reasonable results. The cash working capital requirement resulting from the delay in customers paying their bills or revenue lag totaled $167,335,000 as shown in Schedule B-5, Line 1. This was more than offset by Columbia's payment management of its expenses which totaled $167,359,000 as shown on Line 31 of Schedule B-5. Other working capital items totaled $200,573, 000 as shown on Lines 32 through 36 with a total working capital claim of $200,550,000 as presented on Line 37.

Q: Does this complete 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

PREPARED DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

☐ **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**

☐ **OPERATING INCOME**

☐ **RATE BASE**

☐ **ALLOCATIONS**

☐ **RATE OF RETURN**

☐ **RATES AND TARIFFS**

[X] **OTHER**

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COLUMBIA GAS OF OHIO, INC.

March 17, 2008

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PREPARED DIRECT TESTIMONY OF JOHN J. SPANOS]

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING VALUATION AND RATE CONSULTANTS, INC.?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003 and December 2007.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June, 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric industry: Chugach Electric Association, Duke Energy Ohio, Inc. ("DE-Ohio"), Duke Energy Kentucky, Inc. ("DE-Kentucky"), Northwest Territories Power Corporation and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: Trans Canada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, DE-Ohio, DE-Kentucky, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state Public Utility Commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December, 2000, I was promoted to my present position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and I became responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania American Water Company; Aqua Pennsylvania; Kentucky American Water Company; Virginia American Water Company; Indiana American Water Company; Hampton Water Works Company, Omaha Public Power District, Enbridge Pipe Line Company, Inc., Columbia Gas of Virginia, Inc., Virginia Natural Gas Company, National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions, The City of Bethlehem - Bureau of Water, The City of Coatesville Authority, The City of Lancaster - Bureau of Water, Peoples Energy Corporation, The York Water Company, Public Service Company of Colorado, Enbridge Pipelines, Enbridge Gas Distribution, Inc., Reliant Energy-HLP, Massachusetts-American Water Company, St. Louis County Water Company, Missouri-American Water Company, Chugach Electric Association, Alliant Energy, Oklahoma Gas & Electric Company, Nevada Power Company, Dominion Virginia Power, NUI-Virginia Gas Companies, Pacific Gas & Electric Company, PSI Energy, NUI - Elizabethtown Gas Company, Cinergy Corporation – CG&E, Cinergy Corporation – ULH&P, Columbia Gas of Kentucky, SCANA, Inc., Idaho Power Company, El Paso Electric Company, Central Hudson Gas & Electric, Centennial Pipeline Company, CenterPoint Energy-Arkansas, CenterPoint Energy – Oklahoma, CenterPoint Energy – Entex, CenterPoint Energy - Louisiana, NSTAR – Boston Edison Company, Westar Energy, Inc., PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Municipal Light and Power; Anchorage Water and Wastewater Utility; Public Service Company of North Carolina, Inc.; Kentucky American Water Company; Virginia American Water Company; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; E.ON US Services

Inc.; Public Service Company of North Carolina; South Jersey Gas Company, Duquesne Light Company, MidAmerican Energy Company, Laclede Gas, Duke Energy Company, Duke Energy Carolinas, Duke Energy Ohio Gas, Duke Energy Kentucky, Bonneville Power Administration, NSTAR Electric and Gas Company, EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews and presenting recommended depreciation rates to management for their consideration.

Q. WHAT IS THE EXTENT OF YOUR FORMAL INSTRUCTION WITH RESPECT TO UTILITY PLANT DEPRECIATION?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON PUBLIC UTILITY RATEMAKING MATTERS?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Nevada Public Utility Commission, the Public Utilities Board of New Jersey, the Missouri Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Alberta Energy & Utility Board, the Idaho Public Utility

Commission, the Louisiana Public Service Commission, the State Corporation Commission of Kansas, the Oklahoma Corporate Commission, The Public Service Commission of South Carolina, Railroad Commission of Texas – Gas Services Division, the New York Public Service Commission, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the California Public Utilities Commission, The Federal Energy Regulatory Commission ("FERC"), the Arkansas Public Service Commission, the Public Utility Commission of Texas, the Regulatory Commission of Alaska, and the North Carolina Utilities Commission.

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

A. I sponsor the depreciation study performed for Columbia Gas of Ohio, Inc.

II. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY COLUMBIA GAS OF OHIO IN THIS PROCEEDING?

A. Yes. I prepared the depreciation study submitted by Columbia Gas of Ohio with its filing in this proceeding. My report is entitled: "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2006". This report sets forth the results of my depreciation study for Columbia Gas of Ohio.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. My report is presented in three parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Methods Used in Study, includes descriptions of the basis of the study, the estimation of survivor curves and net salvage and the calculation of annual and accrued depreciation. Part III, Results of Study, presents a description of the results, summaries of the depreciation calculations, graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations.

The table on pages III-4 through III-7 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2006, the calculated annual depreciation accrual and rate and the calculated accrued depreciation for each account or subaccount. The section beginning on page III-8 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-89 presents the results of the salvage analysis. The section beginning on page III-

121 presents the depreciation calculations related to surviving original cost as of December 31, 2006.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line whole life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the cost of fixed capital assets over the useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 391.4, 391.5, 392.1, 392.21, 393, 394, 395 and 398, I used the straight line whole life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2006. The annual amortization is based on amortization accounting that distributes the cost of fixed capital assets over the amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Columbia Gas of Ohio plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1939 through 2006. The transactions included additions, retirements, transfers, sales and the related balances. The Company records included surviving dollar value by year installed for each plant account as of December 31, 2006.

Q. WHAT METHOD DID YOU USE TO ANALYZE THIS SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE COLUMBIA GAS OF OHIO'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R2 indicates an average service life of fifty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. PLEASE USE AN EXAMPLE TO DESCRIBE HOW YOU ESTIMATED THE AVERAGE SERVICE LIVES AND SURVIVOR CURVES UTILIZED IN THIS STUDY.

A. I will use Account 380, Services, as an example because it is one of the largest depreciable groups and represents 28% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1939 through 2006 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1939-2006 and 1977-2006 experience bands are presented on pages III-43 through III-50 of the report. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page III-43 shows $1,364,830 retired at age 0.5 with $497,588,642 exposed to retirement. Consequently, the retirement ratio is .0027 and the surviving ratio is 0.9973. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 50-R2 on page III-42.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1968 through 2006 and considered estimates for other gas companies.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line whole life method, and the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE WHOLE LIFE METHOD OF DEPRECIATION.

A. The straight line whole life method of depreciation allocates the original cost of the property, less future net salvage, in equal amounts to each year of service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units, but small asset values, therefore, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING IMPLEMENTED TO WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.4, 391.5, 392.1, 392.21, 393, 394, 395 and 398 which represent less than two percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 376, Mains, as an example because it is the largest depreciable group and represents 52% of depreciable plant.

As described on page 10 of this testimony, the retirement rate method was used to analyze the survivor characteristics of this property group. The life table for the 1939-

2006 experience band is plotted along with the estimated smooth survivor curve, the 50-R2 on page III-26.

My calculation of the annual depreciation related to the original cost as of December 31, 2006, of utility plant is presented on pages III-136 through III-138. The calculation is based on the 50-R2 survivor curve, 30% negative net salvage and the attained age. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, average life, life expectancy and annual accrual amount and rate. These totals are brought forward to the table on page III-4.

III. CONCLUSION

Q. WAS THE DEPRECIATION STUDY FILED BY COLUMBIA GAS OF OHIO IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. SHOULD THE DEPRECIATION RATES CONTAINED IN THE STUDY FILED BY COLUMBIA IN THIS PROCEEDING BE APPROVED BY THE COMMISSION FOR COLUMBIA'S CALCULATION OF ITS FUTURE DEPRECIATION EXPENSE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREPARE DIRECT TESTIMONY?

A. Yes.

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

PREPARED DIRECT TESTIMONY OF
SUZANNE K. SURFACE
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

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

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March 17, 2008

PREPARED DIRECT TESTIMONY OF SUZANNE K. SURFACE

Q: Please state your name and business address.

A: My name is Suzanne K. Surface 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 title is Director of Strategic Regulatory Initiatives.

Q. Please describe your professional experience and educational background.

A. Since 1996, I have held my current position as Director of Strategic Regulatory Initiatives. I previously was employed as a Manager of Regulatory Services for Columbia Gas of Kentucky, Inc. from 1993 to 1996. From 1986 to 1993 I held positions of increasing responsibility in the Rates and Regulatory departments for Columbia Gas of Pennsylvania, Inc. and Columbia Gas of Maryland, Inc. I received a Bachelor of Arts degree in Economics from Wittenberg University in 1986 and a Masters in Business Administration from Capital University in 1998.

Q. Please describe your duties and responsibilities as Director of Strategic Regulatory Initiatives.

A. I am primarily responsible for managing the strategic planning process and compliance matters for the regulatory area. I have management responsibilities for Columbia's WarmChoice low-income weatherization program, our Customer Relations Department and

Local Governmental Affairs. I am responsible for representing Columbia's interests in Ohio administrative proceedings, and ensuring compliance with Ohio Administrative Codes such as the House Bill 9 rules, the Minimum Gas Service standards and the Credit and Collection and Disconnection rules. I am also responsible for coordinating customer communications on regulatory matters. I have participated in negotiating a series of numerous complex and integrated settlements regarding the establishment of Columbia's Customer CHOICE^{SM} program and Columbia's natural gas riser application. In this proceeding, I prepared and am supporting the proposed tariff changes, and the adjustment to funding levels for the WarmChoice Program.

Q. Have you previously testified before this Commission or any other state Commission?

A. I filed prepared testimony and testified before the Maryland and Pennsylvania state regulatory commissions on revenue and rate base matters. I have also filed prepared testimony in rate proceedings in Kentucky, and in support of Columbia's riser application in Ohio.

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

A. I sponsor Schedules E1-A, E1-B, E-2 and E-3, which contain a clean copy of the proposed tariff sheets, a scored tariff with additions underlined and deletions stricken, the current tariff, and a description and rationale for the proposed tariff changes. I further sponsor the proposed funding levels for the continuation of the WarmChoice program, which is a weatherization program for low-income customers.

Q. What is the source of the information contained in the schedules you are sponsoring?

A. The base rates reflected in the proposed tariffs have been provided to me, and are supported, by witness Russell Feingold. The changes to the definition of the term "Account" is supported by witness Heather Bauer. The changes to the application and method of calculating the Gross Receipts Tax Rider is supported by witness Larry Martin. The rationale for the provision of a 5% discount to customers designated as schools is supported by witness Tom Brown. All other tariff changes are explained in Schedule E-3 and are further supported by my testimony herein.

Q. Please Describe Schedule E1-A.

A. Schedule E1-A sets forth a clean version of each tariff sheet on which Columbia proposed additions, deletions, revised rates, and/or revised text. Those tariff sheets that are unchanged were not included in Schedule E1-A.

Q. Please Describe Schedule E1-B.

A. Schedule E1-B provides the linkage between the currently effective tariff, Schedule E-2, and the clean version of the proposed tariff sheets shown in Schedule E1-A. Schedule E1-B begins with the currently effective tariff. Every addition to the current tariff is underscored, and every deletion is shown as a strikethrough. Revisions to text or to rates are reflected as a strikethrough of the current information with the new information underscored immediately adjacent. Those tariff sheets that are unchanged were not included in Schedule E1-B.

Q. Please Describe Schedule E-2.

A. Schedule E-2 is a copy of Columbia's tariff which was effective as of the date of the filing of Columbia's application. The current tariff was provided in its entirety.

Q. Please Describe Schedule E-3.

A. Schedule E-3 provides a rationale for the proposed tariff changes. This schedule provides an explanation of the changes proposed for each tariff sheet and the rationale for the change. The schedule also cross references the tariff sheet identifier number with the references for Schedules E1-A, E1-B and E-2.

Q. Please describe the main objectives of the changes that Columbia is proposing to make to the tariff.

A. Columbia has proposed changes to the tariff to achieve the following objectives:

- Better organization of the tariff,
- Updated miscellaneous charges to reflect current costs to provide services,
- Rate design changes to reflect a shift over time to recognize the recovery of fixed distribution costs through monthly delivery charges or customer charges, and
- Elimination of riders that are either no longer effective or where the costs have been incorporated into the cost of service in this base rate application, establishment of new riders, and modifications to existing riders.

Q. What changes has Columbia made to provide for better organization of the tariff?

A. In terms of overall tariff changes, Columbia proposes changes to the tariffs to provide for better organization of the sections of the tariff, and better consistency and alignment between the sections within the structure of the tariff. Some of these changes include:

1. Renumbering the part numbers of each section so that Columbia may add new tariff provision to a section without impacting the numbering of other tariff sections.
2. Better organization of the information within the tariff sections so that the sections are more easily navigated. Section I – Service, Section II - Metering and Billing, Section III – Physical Property and Section IV – General contain tariff provisions that apply to all service classes. Information specific to each service class, Section V – Sales Service, Section VI – Gas Transportation Service and Section VII - Competitive Retail Natural Gas Service, is now contained within that same tariff section. To accomplish this, some tariff information was moved to Sections I – IV, and some tariff provisions (such as Billing Adjustments and Definitions) were recreated for Sections V – VII.
3. Elimination of definitions and descriptions of riders within rate schedules. This information is now shown within the Billing Adjustments and Definitions provisions. Duplicate information has been eliminated where possible so that there are not conflicting definitions or provisions.
4. Numerous minor changes to make the tariff more consistent, cohesive and reflective of current practices.

Q. What are Columbia's proposed changes to the Miscellaneous Charges?

A. Columbia is proposing the following changes in Miscellaneous Charges:

1. Columbia is proposing to increase the Reconnection Trip Charge from \$19.00 to \$60.00, the Dishonored Check Charge from \$8.00 to \$18.00, an amendment to the Late Payment Charge to reflect a late payment fee of 1.5% on a customer's entire past due balance, and to increase to the Tie-in Charge from the lesser of actual or \$290.00 to the lesser of actual or \$475.00. Columbia has not amended its fees and charges for miscellaneous services since 1994. The increases to these fees represent the current actual cost to perform the services. The increased service fees allow Columbia to collect costs appropriately from those customers who incur such costs. Columbia proposes to credit the revenues collected from these fees against the Bad Debt Tracker. The change in the Late Payment Charge is proposed to properly assess the carrying charges of past due amounts to the customer who incurs them, and to act as a deterrent to late payments.
2. Columbia has proposed to eliminate the After Hours Reconnection Charge, the Meter Test Charge and Automatic Meter Reading Charge. The elimination of the After Hours Reconnection Charge is proposed because Columbia does not typically schedule reconnections after regular working hours. The Meter Test Charge has been eliminated because the Section II, Part 1 of the Tariff defines the charges for meter testing. The elimination of the Automatic Meter Reading Charge is proposed because Columbia is proposing to install Automatic Meter Reading devices ("AMRDs") on all inside and inaccessible outside locations as part of its Alternative Regulation Plan. If the plan is approved, Columbia will no longer charge customers for AMRD installations. If the plan is not approved, Columbia requests the ability to restore the Auto-

matic Meter Reading Charge at a rate that represents the current actual cost to install the units as part of this tariff proposal.

3. A Theft of Service Investigation Fee of $95.00 has been added, to offset the costs incurred in investigating situations of fraudulent use or tampering. The fee will not be charged unless Columbia has reasonable proof that a theft of service has occurred.

Q. What changes is Columbia proposing for the rate schedules?

A. Columbia is proposing the following changes to rate schedules:

1. As described further in Columbia witness Feingold's testimony, Columbia has determined that it is reasonable and appropriate to collect the proposed revenue requirement from its customers through a phased-in Monthly Delivery Charge for the Small General Service, Small General Transportation Service, and Firm Requirements Small General Transportation Service rate schedules. Under this rate design, all delivery service costs incurred by Columbia that are fixed in nature are collected through a monthly delivery charge that is independent of gas usage.

2. For the General Service and Large General Service rate classes, the distribution costs to serve these customers were found to be too heterogeneous to move to an entirely fixed monthly recovery without causing substantial intra-class revenue shifts. For these customers, Columbia has increased the Customer Charge. Columbia has also proposed to add an additional usage block to the General Service, General Transportation Service, and Firm Requirements General Transportation Service rate schedules. The new block, which applies to monthly volumetric throughput in excess of 25 Mcf

up to 100 Mcf was established to achieve more equally distributed unit rates across the gas consumption ranges within this rate class.

3. As described further in Columbia witness Brown's testimony, a new schools rate has been added to the Small General Service, Small General Transportation Service, Firm Requirements Small General Transportation Service, General Service, General Transportation Service, and Firm Requirements General Transportation Service rate schedules. These rates are available to all primary and secondary school customer accounts, and provide for a 5% discount from the otherwise applicable rate schedule.
4. The Murphy General Service and Full Requirements Murphy General Transportation Service rate schedules have been eliminated. As described in Schedule E-3, the joint agreement between Murphy Gas, Inc. and Columbia provided that the base rates of Columbia and Murphy would be maintained until new rates became effective after Columbia's next base rate filing. Accordingly, Columbia proposes to serve the former Murphy Gas customers under the appropriate Columbia rate schedule effective with the implementation of new rates in this proceeding.

Q. **What changes is Columbia proposing for the Billing Adjustments?**

A. Columbia proposes the following changes to its Riders:

1. Elimination of riders that are no longer in effect, such as the Gas Transportation Service Transportation Take-Or-Pay Surcharge and the UPL Customer Surcharge.
2. Elimination of riders due to the fact that the billing adjustment that was previously reflected through the rider is proposed to be collected or credited through the development of Columbia's cost of service in this application. These include the Small Gen-

eral Service Temporary Base Rate Revenue Rider, the General Service Temporary Base Rate Revenue Rider, the Large General Service Base Rate Revenue Rider, and the Competitive Retail Natural Gas Surcredit Rider.

3. Addition of the new Infrastructure Replacement Program Rider and the Demand Side Management Rider to recover the costs associated with these programs.
4. As described further in Columbia witness Martin's testimony, the Gross Receipts Tax Rider has been amended to reflect recovery of gross receipts taxes on all billed revenues rather than just gas cost revenues. Because of this change, the Gross Receipts Tax Rider is now also applicable to the transportation rate schedules. If the Gross Receipts Tax Rider is approved as proposed by Columbia, a corresponding reduction to the revenue requirement will be made to reflect the collection of gross receipts taxes through the rider.

Q. What other tariff changes would you like to discuss?

A. There are three primary changes that have been made to Sections I – IV of the tariff. The first is that we have amended the language relating to the customer's responsibilities related to customer service lines. The amended tariff now reflects that the customer is no longer responsible for installing, repairing or replacing service lines from the curb or lot line to the meter. Currently, the customer service line is owned by the customer, and the above referenced responsibilities are solely borne by the customer. In this application, Columbia proposes that it will assume these responsibilities, and that it will have the authority to capitalize its investments in the installation, repair and replacement of customer service lines as they occur. This matter is further discussed in the testimony of Columbia witness Roy.

Second, Columbia has added conditions defining the circumstances under which customers may combine accounts for the purposes of billing. This change is further described in Columbia witness Bauer's testimony.

Third, Columbia has proposed changes to its line extension policy. This change is further described in Columbia witness Lockhart's testimony.

Q. Please describe Columbia's proposal for funding of the WarmChoice program.

A. The WarmChoice program is a nationally recognized whole-house weatherization program that is provided to customers at or below 150% of the federal poverty guidelines. WarmChoice provides conservation services to customers who would otherwise be unable to afford them, benefiting the customer who receives WarmChoice by reducing their energy bills by 27% on average, and by up to 60% for some individual homes. WarmChoice benefits all other customers as well by helping to lower bad debt expenses and PIPP arrearages, which are ultimately borne by all ratepayers. The WarmChoice program is currently funded through base rates. The revenue requirement in Case No. 94-987-GA-AIR included a WarmChoice annual expense totaling $5,090,000. In 2003, Columbia agreed to fund an additional $500,000 to its WarmChoice program as part of Case No. 03-1127-GA-UNC. Columbia is proposing to increase its current WarmChoice program from the current funding level of $5.5 million to $7.1 million, as shown on Schedule C-3.15.

Q. Why is Columbia proposing to increase the funding level of WarmChoice from $5.5 million to $7.1 million?

A. Columbia proposes that the increase to the level of WarmChoice funding is reasonable and appropriate in order to keep pace with the impacts of inflation upon the cost of delivering WarmChoice services. Since 1994, the cost of installing WarmChoice measures has increased with inflationary pressures. At the same time, declining throughput has caused Columbia to underrecover the annual funding level for the WarmChoice program. Columbia and its WarmChoice providers have worked hard to control the costs of the energy conservation measures over the years with limited price increases for the installed costs of these measures. Despite these efforts, the impact of the declining purchasing power of the WarmChoice funding is reflected in the numbers of households that the program has been able to serve. In the mid-1990's, WarmChoice was able to serve approximately 1,700 households annually, but today, WarmChoice is only able to serve approximately 1,200 households annually. Columbia proposes to increase the funding based on applying the annual consumer price index to the initial 1994 funding level and compounding it over the 14 years since the last base rate case. This increase will restore WarmChoice in today's dollars to the level of funding that was allowed in Columbia's 1994 base rate case.

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

PREPARED DIRECT TESTIMONY OF
STEVEN VITALE, PH.D., P.E.
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

☐ **MANAGEMENT POLICIES, PRACTICES AND ORGANIZATION**

☐ **OPERATING INCOME**

☐ **RATE BASE**

☐ **ALLOCATIONS**

☐ **RATE OF RETURN**

☐ **RATES AND TARIFFS**

[X] **OTHER** **Accelerated Mains Replacement Program**

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COLUMBIA GAS OF OHIO, INC.

March 17, 2008

PREPARED DIRECT TESTIMONY OF STEVEN VITALE, PH.D., P.E.

Q: Please state your name and business address.

A: My name is Steven Vitale and my business address is 118 Fern Drive, PMWF, Milford, Pa. 18337.

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

A. I have been retained by Black & Veatch Corporation ("Black & Veatch") as an expert witness in this case regarding natural gas distribution operating systems. I am also the President of Vitale Technical Services, Inc.

Q. Please describe Black & Veatch

A. Black & Veatch was founded in 1915 and it is a global engineering, consulting and construction company specializing in infrastructure development in energy, water, telecommunications, federal, management consulting and environmental markets. It has more than 9,600 professionals working in more than 100 offices worldwide.

Q. What is your educational background?

A. I have a Bachelor's degree in Mechanical Engineering, a Master's Degree in Civil Engineering, a Masters Degree in Mechanical Engineering, and a Doctorate Degree in Mechanical Engineering. I have taught engineering courses for the Polytechnic University of New York. I presently develop gas technology courses and teach gas technologies for the Gas Technology Institute. These courses are presented internationally.

Q. What are your professional credentials?

A. I have been licensed as a Professional Engineer in 5 states (New York, Rhode Island, Massachusetts, New Hampshire, and Pennsylvania). As the Chief Engineer of KeySpan Energy (a company that distributes gas to 2.5 million gas customers across 3 states) I was the highest ranking technical person in the company. As the developer of gas technology courses I have been called upon by clients to provide professional technical assistance to their operations.

Q. Please briefly describe your professional experience.

A. Before and during college, I worked as a machinist. After obtaining my Bachelor's Degree in 1972 I began work for the Brooklyn Union Gas company which today is a part of KeySpan Energy. I started work in the field installing gas mains and services mostly to replace deficient bare steel and cast iron mains and services. I spent the next 32 years with Brooklyn Union increasing in responsibilities within the Gas Distribution, Gas Production, Gas R&D and Gas Engineering departments. In some of these capacities I was in charge of large field forces that spent most of their time assuring safety, managing leaks, making repair replace decisions and evaluating the deterioration of the gas system. In some of the capacities I was responsible for the planning of the future system, to ensure system safety, reliability and deliverability. In the position of Vice President and Chief Engineer I was responsible for the Gas Engineering of the 21,000 miles of gas mains and all their associated gas services, pressure regulation devices and valves, across 3 states, as well as the operation of 27 production plants and the maintenance of 28 production plants across 4 states. As Chief Engineer I was responsible for the system planning needed to assure a sustainable gas industry into the future. I retired from KeySpan as the Vice President and Chief Engineer in 2004.

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

A. I support Columbia Gas of Ohio, Inc.'s ("Columbia") proposal to implement an Accelerated Mains Replacement Program ("AMRP"). In that regard, I also support the Black & Veatch independent comparison of Columbia's bare steel related data to the U.S. natural gas industry data and the opinions Black & Veatch has formed and expressed in its report entitled "Comparative Analysis of the Bare and Coated Steel Distribution Piping of Columbia Gas of Ohio, Inc." That report is attached hereto as Attachment SV-1.

Q. Please describe the scope of the work that Black & Veatch was asked to perform.

A. Black & Veatch was asked to provide an independent review of Columbia's need for its proposed accelerated bare steel, cast iron and wrought iron mains replacement program based on benchmarking Columbia's data to other natural gas distribution operators.

Q. Please describe how Black & Veatch performed its independent comparison of the Columbia bare steel related data to U.S. natural gas industry data.

A. Black & Veatch utilized U.S. Department of Transportation Office of Pipeline Safety ("DOT") data that was reported annually to the DOT by natural gas distribution operators. We obtained this data for the years 1997 through 2006. Distribution operator data 2007 will not be available until later in 2008. We observed that in 2006 there were 1,383 companies filing reports of which about 1,160 had no bare steel main at all. After reviewing the data, we determined that it was necessary to establish a sorting criterion to help us identify those companies that have large amounts of bare steel in their distribution system. Recognizing that Columbia reported over 3,600 miles of bare steel, Black & Veatch recommended a sorting criterion of a minimum 50 miles of bare steel. We believe those companies with at least this amount of bare steel are facing similar issues regarding maintaining and replacing these pipes. Across the nation there were 83 gas system operators reporting having more than 50 miles of bare steel in their distribution systems. These 83 companies have 97% of all of the bare steel gas distribution system mains in the nation. Within the same geographic region as Columbia there were 30 companies reporting having more than 50 miles of bare steel in their distribution systems. By using the term region, I refer to distribution operating companies in Ohio and the states that border Ohio. Utilizing this data, Black & Veatch then compared certain data of these companies to Columbia. Black & Veatch's report illustrated the results of these comparisons.

Q. What are some noteworthy observations from Black & Veatch's review of the DOT data?

A. We observed that in 2006 Columbia had the largest number of miles of bare steel main of all distribution companies reporting to the DOT. It reported having 3,663 miles of non-cathodically protected bare steel main. It also had the third highest number of corrosion leaks eliminated or repaired on mains of all of the companies reporting. It reported eliminating or repairing 2,820 corrosion leaks on mains which equates to 74% of Columbia's total number of leaks on mains from all causes. These leaks predominately occur on non-cathodically protected bare and coated steel main. These mains represent 19% of Columbia's gas distribution mains.

Q. Why is the focus on corrosion leaks critical to the public and Columbia Gas?

A. Let me describe two reasons why this is important for the public and Columbia. First, as we describe in our report, it is critical because the natural gas industry understands the fact that bare steel pipe, buried in the earth where there is moisture in the soil and without cathodic protection, will corrode over time. This corrosion may occur over the entire surface of the pipe and it may take many years before the first single corrosion leak occurs. However, once the first leak on a pipeline segment occurs, there are other points on the pipe where it is losing metal and where pits are becoming deeper and deeper due to corrosion. As the corrosion pitting continues and the pipes continue to lose metal, these pipes will experience additional leaks in a shorter and shorter timeframe as the corrosion pits completely breach the wall of the pipe. Eventually many additional points of corrosion may result in an unmanageable leak rate as the pipe becomes fragile and sometimes unrepairable. In other words, once a section of pipe starts to develop corrosion leaks, experience has shown that the pipe will develop more and more leaks at a continuously increasing rate over time. Corrosion leaks will increase over time at an exponential rate.

The second reason this is important to the public and Columbia is the fact that Columbia's high number of corrosion leaks is the result of having 3,663 miles of bare steel (enough miles that if the pipes were laid end to end they would stretch from San Francisco to New York City and back to Columbus) that are currently corroding, on average across its system, at a corrosion leak rate of 0.76 corrosion leaks per mile of non-cathodically protected bare and coated steel main. While this corrosion rate is less than the average of the regional companies (1.28), what is of major concern is that due to the age of Columbia's trouble prone pipes, it is reasonable to expect that Columbia's corrosion rate will begin to increase. For example, if Columbia's corrosion leak rate was to rise to the average of regional companies, it would experience an increase in corrosion leaks from 2,820 to 4,755 per year. We believe that such an increase in gas leaks would create additional safety and reliability risks for the public and Columbia's employees, as well as, create a leak management challenge for the Company.

Q. What are Columbia's trouble prone pipes?

A. The natural gas industry recognizes that within a gas distribution system, pipes used to transport natural gas that are buried in the earth and made of the following materials are known to be much less reliable and prone to leakage over time. In other words, they will leak and create both operating and maintenance problems at rates that are not experienced with newer materials that are now the current industry standard, such as plastic and cathodically protected coated steel pipe. The trouble prone materials include, non-cathodically protected bare and coated steel, wrought iron (which corrodes like bare steel), and cast iron (which typically leaks at joints and is prone to breaking due to physical stresses). Typically with these materials, the smaller the diameter, the more susceptible they are to gas leaks due to corrosion or pipe breaks because the wall thickness of these pipes is thinner than larger diameter pipes. For this reason bare steel services should be replaced at the same time that trouble prone mains are being replaced on any street. In addition, the replacement of such services at the time the mains are being replaced is a typical operating procedure and considered a best practice within the natural gas industry.

Q. How does Columbia's rate of replacement of its bare steel mains compare to other companies reporting to the DOT?

A. In 2006, Columbia's annual rate of replacement of non-protected bare steel main was 1.4% or approximately 50.6 miles. Extrapolating Columbia's 2006 rate of replacement into the future would result in the replacement of its bare steel main inventory in approximately 72 years, compared to approximately 26 years for the nation as a whole.

Q. Do you have an opinion, based on your experience, judgment and a reasonable degree of engineering certainty, as to whether Columbia requires an accelerated mains replacement program?

A. Yes.

Q. Please state your opinion.

A. Columbia's 72 year replacement rate, even if it replaced its oldest mains first, would result in the last main being replaced when it is over 120 years old. Black & Veatch believes that these trouble prone mains will continue to corrode at an ever increasing rate for reasons discussed in further detail in our report, and that Columbia's present rate of main replacement results in too long a period of time for these mains to remain in service. It is our opinion that the focus of Columbia's efforts must be towards prioritizing the worst mains for replacement first and accelerating the replacement of these trouble prone mains before the leak rate gets out of hand. Columbia's plan to increase its replacement rate of its aging trouble prone pipe to approximately 160 miles per year represents, in our opinion, a significant increase in its efforts that will have the desired result of reducing gas leaks due to corrosion. This 25 year replacement program will improve both the safety and reliability of its gas distribution system by eventually eliminating the source of 74% of Columbia's gas leaks on mains. Without such an accelerated replacement effort, it is our opinion that Columbia and the public will face the risks associated with an ever increasing number of corrosion leaks. In addition we also believe that Columbia's proposed 25 year accelerated mains replacement program will bring its main replacement program in line with the national average.

Q: Does this complete your Prepared Direct Testimony?

A: Yes, it does.

Comparative Analysis of the Bare and Coated Steel Distribution Piping of Columbia Gas of Ohio, Inc.

ATTACHMENT SV-1

Confidential Attorney Client Work Product Prepared In Anticipation of Litigation and for Discussion Purposes Only – Draft Preparatory Material

March 13, 2008 v1

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Confidential Attorney Client Work Product Prepared In Anticipation of Litigation and for Discussion Purposes Only
Draft Preparatory Material

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Confidential Attorney Client Work Product Prepared In Anticipation of Litigation and for Discussion Purposes Only
Draft Preparatory Material

Executive Summary

At the request of Columbia Gas of Ohio, Inc. ("Columbia" or the "Company"), Black & Veatch Corporation ("Black & Veatch") has performed a comparative analysis of Columbia's non-cathodically protected bare and coated steel distribution piping data. This analysis was based on information reported annually by natural gas distribution operators to the Department of Transportation, Office of Pipeline Safety ("DOT") for the years 1997 through 2006.

The purpose of this analysis was to provide Columbia with: 1) a better understanding of how it compares to national and regional companies on benchmarks related to aging pipeline infrastructure on natural gas distribution systems; and 2) an independent opinion on the need for Columbia to accelerate its replacement program for its: a) bare and non-cathodically protected coated steel mains; b) cast or wrought iron mains; and c) bare and non-cathodically protected coated steel services.

The analysis of the 2006 DOT data reveals that Columbia has the largest inventory of bare steel mains (3,663 miles) remaining in service of all of the nation's gas distribution operating companies reporting to the DOT (1,383 companies), and it has the third highest number of corrosion leaks on mains for all companies. While Columbia has a relatively high number of corrosion leaks compared to other distribution companies, on the basis of corrosion leaks per mile of non-cathodically protected bare and coated steel main experienced during 2006, Columbia had a lower value at 0.76 compared to the average value of 1.28 for regional companies (not including Columbia) and 0.95 for national companies (not including Columbia) that have more than 50 miles of bare steel main in their distribution systems.

The data also shows that 2,820 leaks (74%) of the Company's total leaks on mains were corrosion leaks and that these corrosion leaks predominately occurred on only 19% of Columbia's total inventory of mains. These mains are Columbia's non-cathodically protected bare and coated steel mains.

The focus on the number of corrosion leaks is critical because industry studies demonstrate that "when a section of pipeline system starts to develop leaks, experience has shown that further leaks will develop at a continuously increasing rate."[1] Furthermore, it is Black & Veatch's experience that corrosion leaks on underground non-cathodically protected (unprotected) bare and coated steel pipe can be expected to increase exponentially over time until the pipes are either cathodically protected, retired, or replaced.

In the case of Columbia, the data also shows that even with this high number of corrosion leaks per year, The Company maintained a rate of corrosion leaks on mains per mile of bare and non-protected coated steel main that was lower than the average rate of regional companies. We believe that Columbia's past ability to maintain a favorable corrosion leak rate compared to the region was based on its sound operating practices and experience with bare steel mains. However, as the bare steel pipe inventory continues to age we believe Columbia's leak rate will increase. If the corrosion leak rate (0.76) for Columbia was to simply rise to the level of the average leak rate for regional

[1] Peabody's "Control of Pipeline Corrosion," second edition 2001. Chapter 15, Page 290.

companies in 2006 (1.28) that would mean that Columbia's annual corrosion leaks would increase from 2,820 to 4,755 leaks (a 69% increase). A 69% increase in leaks could create additional safety risks for the public and Columbia's employees, as well as create a serious leak management challenge for the Company. It is our opinion that the focus of Columbia's efforts must be towards accelerating the identification and replacement of its trouble prone mains before the leak rate becomes excessive. Without such an accelerated replacement effort, it is our opinion that Columbia will face the risks associated with an ever increasing number of corrosion leaks. Columbia's has advised Black & Veatch that it has segments of mains that have corrosion rates that are far higher than Columbia's system average.

More than half of Columbia's bare steel and cast or wrought iron mains were installed before 1940. These mains have been exposed to underground external corrosion elements for over 68 years. The remainder is of the pre-1959 vintage which would be between 48 to 68 years old today. Experience and data have taught the natural gas industry that these mains will need to be either retired or replaced with plastic or cathodically protected steel mains. In our opinion it is not a matter of "if" these mains will need to be replaced but "when" these mains need to be replaced in order to reduce the risks and costs associated with leaking gas mains, as well as to maintain Columbia's overarching commitment to safety.

In 2006 Columbia replaced 50.6 miles of its bare steel mains at a rate of approximately 1.4% per year as compared to the national average replacement rate of approximately 3.7% per year. At Columbia's present replacement rate, it would take the Company 72 years to eliminate its problematic bare steel mains compared to 26 years for the nation as a whole (not including Columbia). We believe that Columbia's proposed accelerated mains replacement program (25 years) will bring its main replacement program in line with the national average.

We believe Columbia's efforts must be towards prioritizing the worst mains for replacement first and accelerating the replacement of these trouble prone mains before the leak rate gets out of hand. Without such an accelerated replacement effort it is our opinion that Columbia will face the risks associated with an ever increasing number of corrosion leaks.

Therefore, it is our informed opinion that it is in the best interest of Columbia's customers that it replace its troublesome mains in an accelerated, well planned and well structured manner, rather than to expose customers to the ever-increasing risk and expense of first repairing leaks on such mains, and then replacing them in response to a higher risk and a harder to manage leak rate.

In addition to the customer safety and system reliability benefits mentioned throughout this report, a well planned accelerated main replacement program would have a host of qualitative benefits for the public such as fewer unplanned disruptions to traffic on roads for emergency gas leak repairs, and improved coordination with local town and village governments. Although these quality of life benefits are dwarfed by the safety and reliability benefits, it is Black & Veatch's opinion that prudent utility system operators need to manage in a manner that protects the customer, assures the integrity of the gas system, and does not inconsiderately inconvenience the customers' quality of life.

Based on the data comparisons completed by Black & Veatch and its interviews with Columbia operating staff, regarding the management of its corrosion leaks, the Company has been a good steward of it gas system as evidenced by its ability to manage its corrosion leakage rates thus far. Black & Veatch recognizes and supports Columbia's concern for the safety of its customers and employees and its desire to be a good manager of the gas system it operates.

We believe that in order to continue to be a good operator of its gas system, a systematic accelerated replacement of the problematic mains is required.

Black & Veatch recommends that the Public Utility Commission of Ohio ("PUCO") support and approve the implementation of Columbia's proposed accelerated mains replacement program.

Purpose of the Report

Columbia Gas of Ohio, Inc. ("Columbia" or the "Company") is requesting approval from the PUCO for an annual rate adjustment mechanism to support its proposed accelerated replacement program for its unprotected bare and coated steel, cast iron and wrought iron mains and services.

Columbia believes such a program is necessary because, while it has been working diligently to maintain its aging mains, a higher level of effort and investment will be required by Columbia to ensure that its leak experience remains manageable and that safety and reliability is maintained.

Columbia has requested Black & Veatch provide: 1) a better understanding as to how Columbia compares to national and regional companies on benchmarks related to aging pipeline infrastructure of natural gas distribution systems and 2) an independent opinion as to the need for a Columbia accelerated replacement program for its: a) non-cathodically protected bare and coated steel mains, b) cast or wrought iron mains; and c) non-cathodically protected bare and coated steel services.

The Data Utilized

This section identifies the data utilized in the analyses, discusses specific characteristics of the data that are relevant to the analysis, and advises on the use and interpretation of the information. In performing the analyses, Black & Veatch utilized data from the U.S. Department of Transportation Office of Pipeline Safety ("DOT") web site, as well as Black & Veatch's calculations using this data.

Department of Transportation Data

Gas distribution pipeline operators are required by the DOT to annually submit certain main, service and leak data utilizing DOT form PHMSA[2] F7100.1-1. This data is available to the public through the DOT web site. (http://ops.dot.gov).

The DOT data, as of December 2007 included the following data for the years 1997 to 2006:

- Miles of non-cathodically protected bare steel, coated steel mains and other categories of main material in the system at the end of each year;
- Number of corrosion leaks eliminated or repaired for mains and services;
- Number of total leaks eliminated or repaired for mains and services for various leak causes; and
- Number of leaks remaining in backlog at year-end.

Corrosion Leaks

While DOT data provides the total number of corrosion leaks for mains, DOT does not provide a breakdown of the number of corrosion leaks by type of main material. Due to this DOT data limitation, for the purposes of this review, we assumed that the reported corrosion leaks on mains predominately occurred on either non-cathodically protected bare steel or non-cathodically protected coated steel mains.

Based on our experience we believe that this assumption is reasonable since, while it is recognized that corrosion leaks can occur on cathodically protected coated steel mains, most corrosion leaks occur on unprotected bare steel and coated steel. Our opinion is supported by data provided by Columbia which identified that 96% of all its corrosion leaks on mains in 2006 occurred on bare steel mains. More specifically, operating experience leads one to conclude that:

- Mains that are cathodically protected, while they occasionally develop corrosion leaks, are generally protected from corrosion leaks;
- Cast iron main leaks are typically not caused by corrosion (graphitization) and are generally caused by leaking joints or main breaks; and
- Plastic mains do not corrode.

Black & Veatch Calculations

Utilizing DOT data, Black & Veatch prepared several comparisons and developed certain metrics to assist in comparing Columbia to other companies. They included comparisons related to:

[2] Pipeline and Hazardous Materials Safety Administration

- Annual change in bare and unprotected coated steel mains inventory.
- Annual change in corrosion leaks eliminated or repaired
- Annual number of corrosion leaks eliminated or repaired per mile of bare and unprotected coated steel main.
- Leak causes
- Types of material
- Annual number of corrosion leaks eliminated or repaired per 1,000 bare and unprotected coated steel services.
- Year end backlog of leaks pending repair
- Ratio of the number of leaks in backlog at year-end to the annual number of total leaks repaired. This is referred to as the Leak Backlog/Repair Ratio.

If the DOT data was missing a data point for a particular company, in a given year, Black & Veatch substituted for the missing data point the average data of the prior and subsequent year.

Observations Regarding the Data:

- The DOT 2006 database contained data for 1,383 companies.
- Most of the companies that filed with the DOT do not have bare steel mains or have a very small amount of bare steel mains compared to Columbia.
- DOT Database Sorting Criterion – Black & Veatch utilized a sorting criterion intended to limit the focus to companies with a significant amount of bare steel, yet still incorporate a reasonable sample of companies. The sorting criterion chosen was all companies with a minimum of 50 miles of bare steel in 2006. Additional data which reinforced the reasonableness of this sorting criterion included:

    - Nationwide, 83 companies, including Columbia, meet the 50 miles of bare steel sorting criterion. They are listed in Appendix A to this report. Generally, these are also investor owned companies that are larger in size than the average company reporting, as measured by the number of gas services (68 have more that 50,000 services), and are subject to state regulatory oversight similar to Columbia.
    - The 83 nationwide companies meeting the sorting criterion represent 97% of the bare steel in the DOT 2006 database (50,919 miles out of 52,686 miles).

- Regional Analysis – In addition to the national sorting criterion of 50 miles, Black & Veatch determined that Columbia data might also be reasonably compared to companies in close regional proximity to Columbia. Companies in the states bordering Ohio were thought by Black & Veatch and Columbia to possibly experience more similar environmental characteristics (such as weather, soil and age of pipe material) than companies in other areas of the United States.

    - The regional states selected include: Indiana, Kentucky, Michigan, Ohio, Pennsylvania and West Virginia.
    - There are 30 companies, including Columbia, that meet the sorting criterion and are located in the six regional states. They are listed in Appendix B.
    - The 30 regional companies meeting the sorting criteria represent 44% of the bare steel in the DOT 2006 database.

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Findings and Opinions

1. Columbia's inventory of mains by material type

A review of a company's corrosion leak related activity begins with an understanding of the types and amounts of main material existing in its system.

DOT 2006 data shows that Columbia reported having 3,663 miles of bare steel and 52 miles of non-protected coated steel mains remaining in its system (Figure 1). Bare steel accounts for 19% of Columbia's total inventory of distribution mains and non-protected coated steel main accounts for 0.3%.

While there remains 52 miles of non-protected coated steel in the Columbia system, it is Black & Veatch's opinion that Company will first be guided by industry best practices and attempt to apply adequate cathodic protection to these mains, and if that is not possible, it would need to plan to retire or replace them with plastic or cathodically protected coated steel mains.

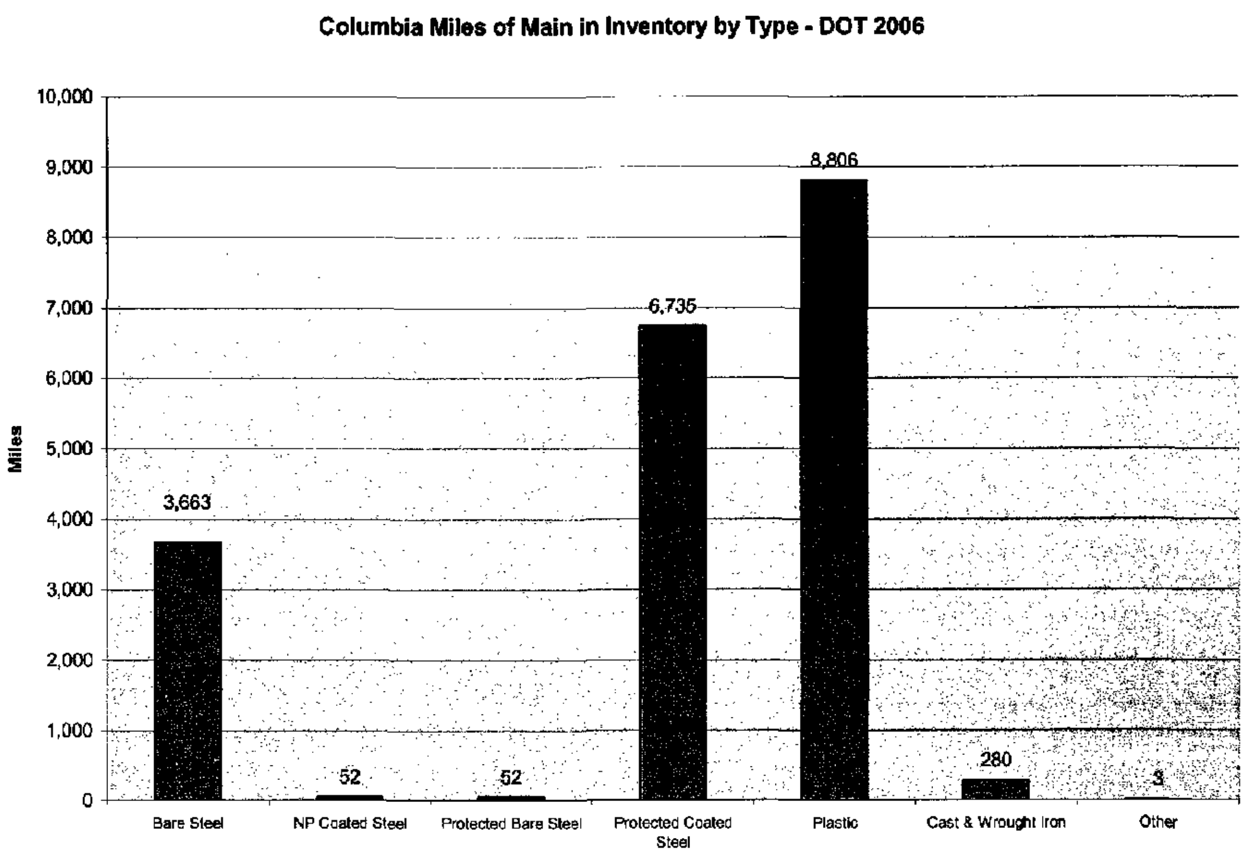

Figure 1

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2. Miles of bare steel main comparison - 2006

What is significant about the amount of bare steel in Columbia's inventory is that it has the greatest amount of non-protected bare steel in its inventory compared to all other distribution operators reporting to the DOT. Figure 2 illustrates Columbia's miles of bare steel compared to national and regional companies.

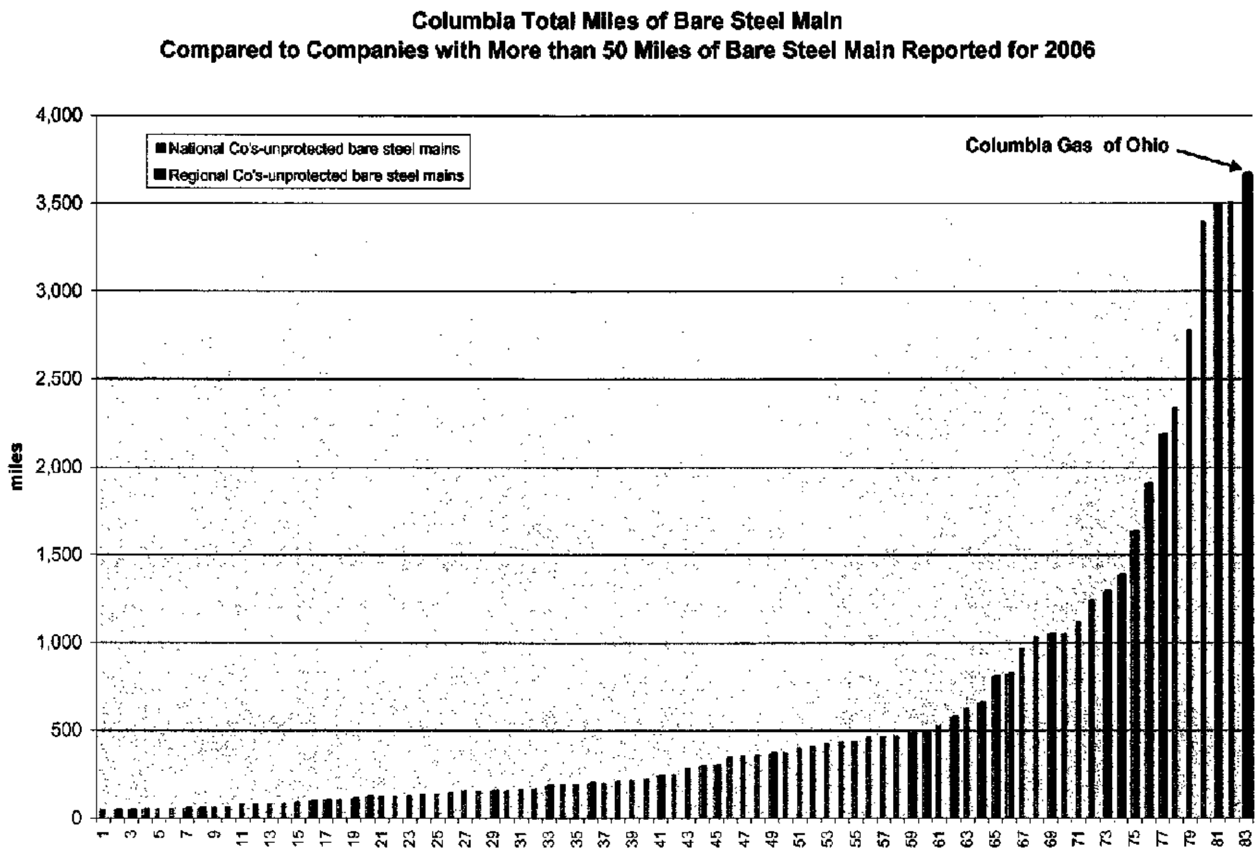

Figure 2

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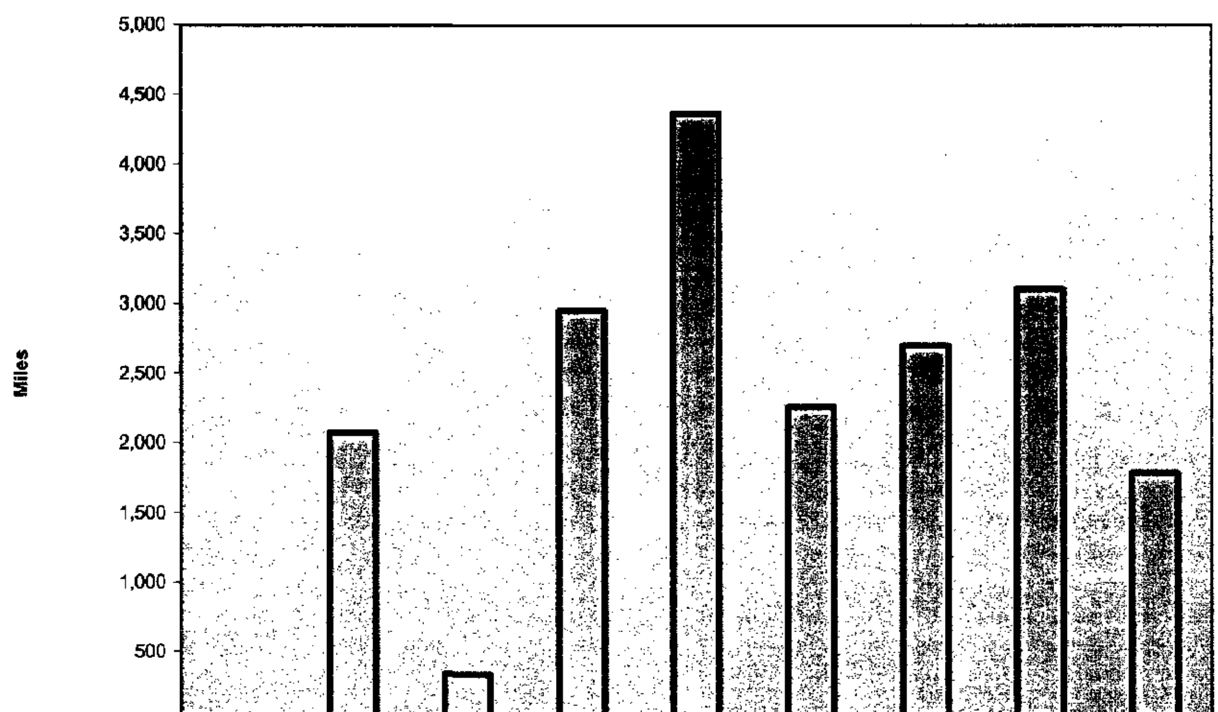
3. Columbia's miles of main by year installed

The number of years that these mains have been buried in the ground is a major contributing factor to an ever increasing amount of corrosion leaks over time. Figure 3 illustrates the mile of mains by year installed in Columbia's system. From this chart one can see that 2,069 miles of main have been installed more than 68 years ago and 3,296 miles have been installed since 1940 through 1959 (between 48 and 68 years ago).

As explained in further detail later in this report, experience and data have taught the natural gas industry that these mains will need to be either retired or replaced with plastic or cathodically protected steel mains. In our opinion it is not a matter of "if" these mains will need to be replaced but "when" these mains need to be replaced in order to reduce the risks and costs associated with leaking gas mains as well as to maintain Columbia's overarching commitment to safety. It is Black & Veatch's opinion that replacing such a large amount of bare steel, in a pragmatic and efficient manner, will require a considerable amount of planning, effort, and expense on the part of Columbia's management. The historic sequence of main installations was to install cast iron, wrought iron and bare steel pipe in the early years and then in later years to install coated steel and plastic pipe. Therefore, we believe that most of the 3,663 miles of bare steel main in service today was installed prior to 1959.

Columbia Miles of Mains by Year Installed
DOT 2006



	Unknown	Pre 1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009
Miles of main	0	2069	339	2957	4371	2263	2702	3105	1785

Figure 3

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4. Columbia's leaks by cause

During 2006 Columbia reported experiencing 3,828 leaks that were eliminated or repaired on mains. Corrosion leaks on mains accounted for 2,820 or 74% of the Company's total number of leaks on mains (as illustrated in Figure 4).

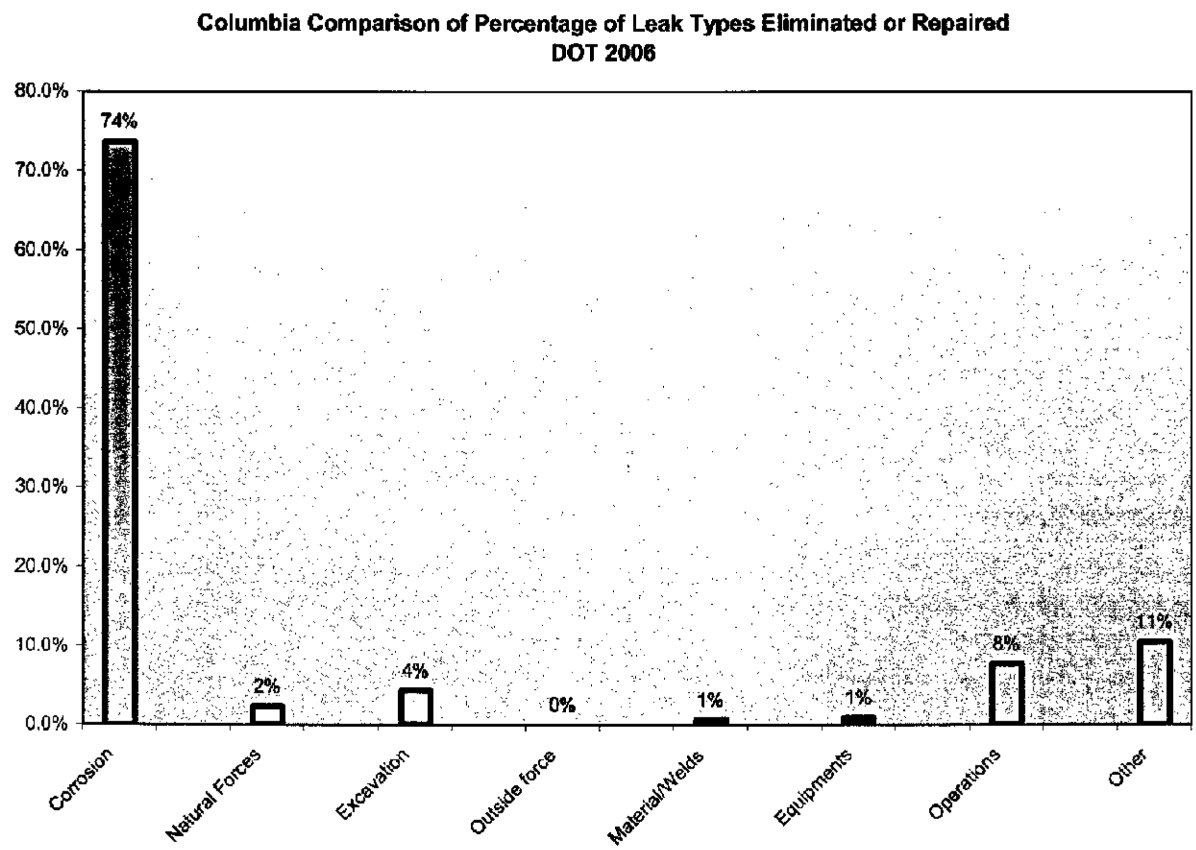

Figure 4

5. Total corrosion leaks on mains comparison - 2006

Columbia's level of corrosion leaks on mains in 2006 ranks as the third highest out of the 83 companies in the DOT database with more than 50 miles of bare steel in their systems. This fact is illustrated in Figure 5.

It is Black &Veatch's opinion that Columbia's large number of corrosion leaks resulting from a very large inventory of aging bare steel mains creates additional maintenance, reliability and safety risks that it must diligently manage.

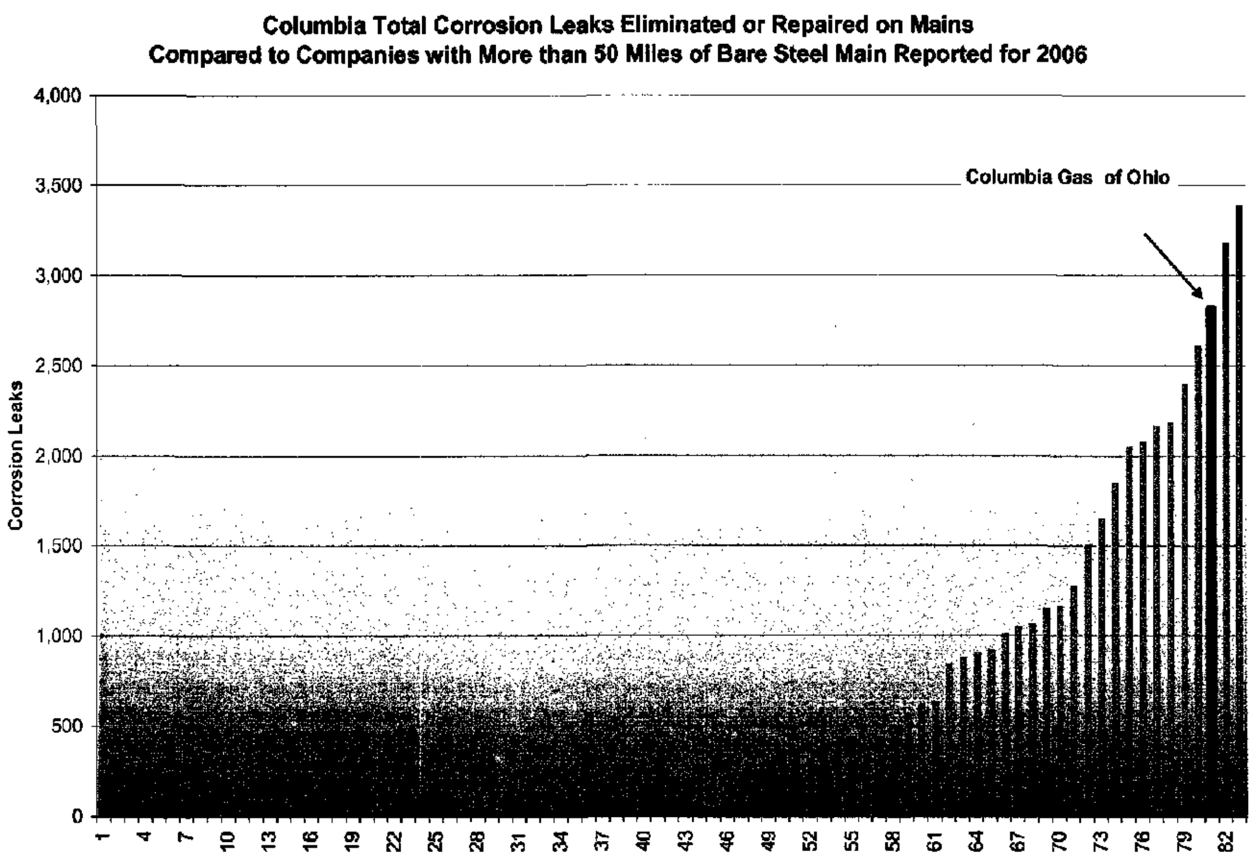

Figure 5

6. Total corrosion leaks on mains compared to bare steel main inventory

In 2006 Columbia's rate of replacement of bare steel was 50.6 miles or approximately 1.4% and the nation's was 3.7%. Figure 6 illustrates the reduction in Columbia's bare steel inventory and the change in corrosion leaks on mains for the period 1997 – 2006.

Extrapolating Columbia's 2006 rate of replacement (50.6 miles per year) into the future would result in the replacement of its bare steel main inventory in approximately 72 years, compared to approximately 26 years for the nation as a whole.

At Columbia's present replacement rate, if a plan to remove the oldest mains first was implemented, at the end of the 72nd year, the last pipe to be replaced would be older than 120 years.

Columbia's bare, non-protected coated steel, and cast & wrought iron mains are its oldest pipelines. The Company reports that more than 2,000 miles of main are in the pre-1940 category. If one were to assign a weighted average year of installation to the pre-1940 grouping of mains of 1930, then the average age of Columbia's total bare steel and cast iron of this vintage would be approximately 78 years. As stated above, a 72 year replacement rate, even if it replaced the oldest mains first, would result in the last main being replaced when it is over 120 years old.

Black & Veatch believes that these mains will continue to corrode at an ever increasing rate for reasons discussed in further detail in this report, and that Columbia's present rate of main replacement results in too long a period of time for these mains to remain in service.

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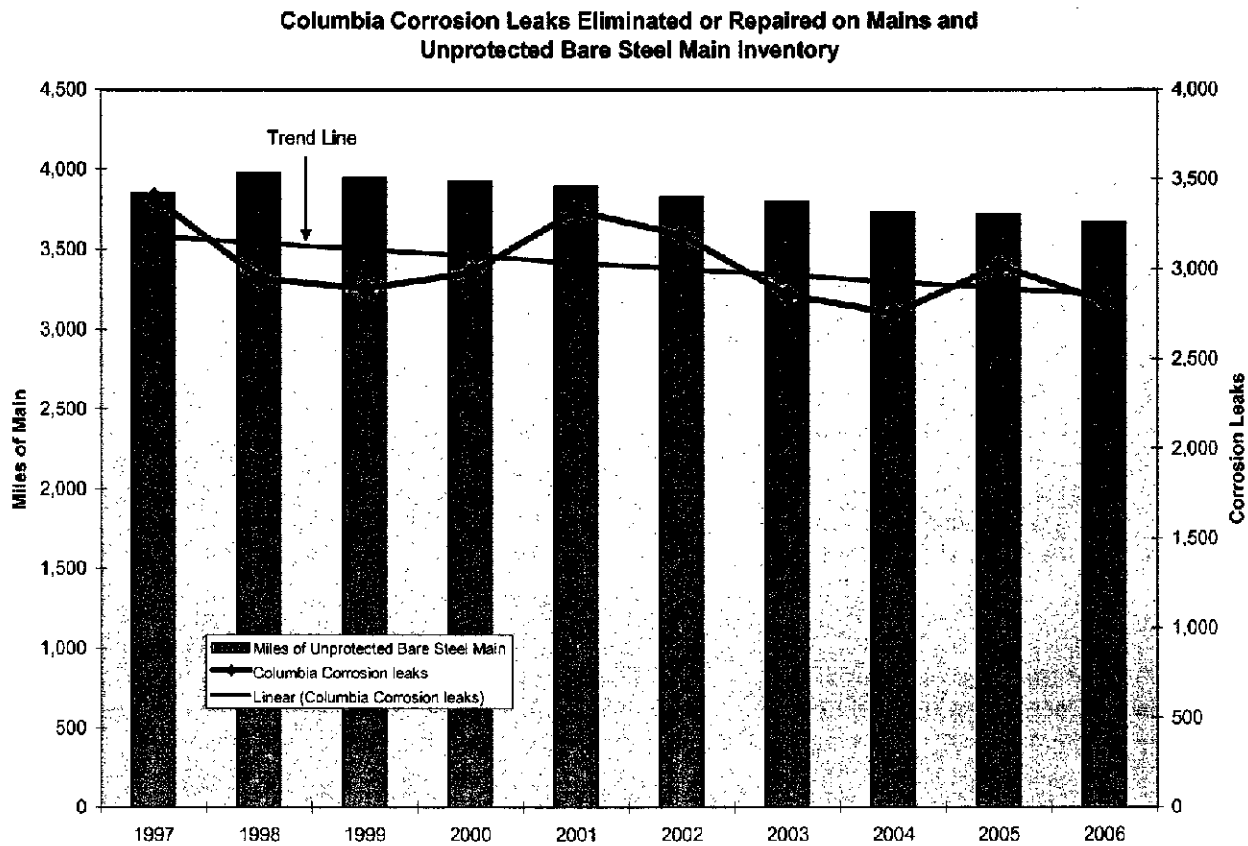

Figure 6

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7. Columbia's change in corrosion leaks – 1997 - 2006

The Company has experienced a high level of corrosion leaks for the period 1997 – 2006. This is illustrated in Figure 7 where it is compared to average number of corrosion leaks for regional companies with more than 50 miles of bare steel main in their systems.

Columbia manages its corrosion leaks with practices and procedures designed to eliminate or repair the leak and to help slow the growth of future corrosion leaks. Such procedures include the best practices of installing at the time of a repair of a corrosion leak on a bare steel main, one or more directly connected magnesium anodes (depending on the length of main exposed). The Company also maintains a data base of all leaks, causes, material, etc that it uses to analyze which main segments are becoming more troublesome and requiring immediate replacement rather than repair.

These practices have helped Columbia manage corrosion leaks at a relatively flat rate to date. However, as discussed further in this report, the Company and B&V anticipate an increase in the number of future corrosion leaks on their system.

The Company is also currently implementing a pipeline integrity management decision support software tool called Optimain. Using Columbia data and its experience from other companies, it will help Columbia by providing a dynamic system-wide risk assessment tool to help prioritize the mains being replaced and optimize capital spending.

Columbia Corrosion Leaks Eliminated or Repaired on Mains per Year Compared to Regional Companies with More than 50 Miles of Bare Steel Main Reported for 2006

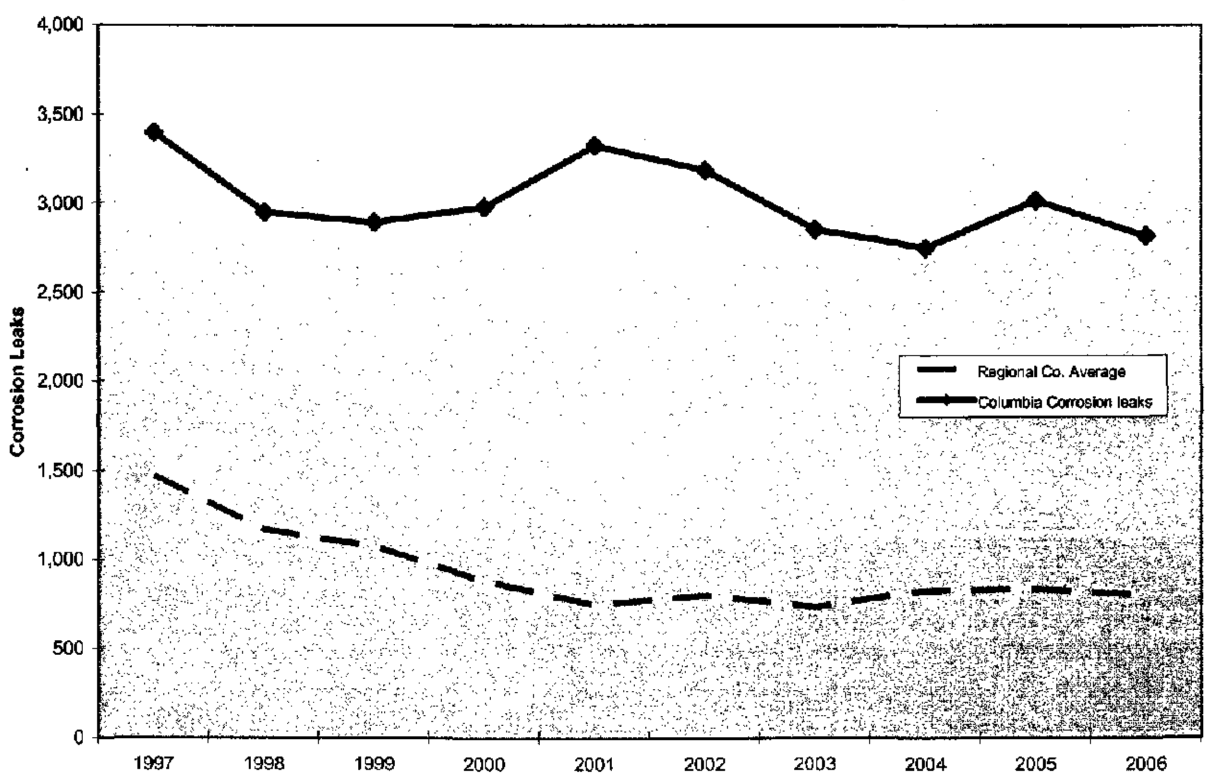

Figure 7

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8. Corrosion leaks per mile of non-protected bare steel and coated steel – 2006

The measure of corrosion leaks per mile of unprotected bare steel and coated steel main is a frequently used metric to illustrate the condition of these mains in a distribution system. Figure 8 compares for 2006, this measure for all companies having more than 50 miles of bare steel main in their system. It can be seen that Columbia's rate of 0.76 is better than the region and national averages. The average rate of the regional companies is 1.28 and average rate of the national companies is 0.95 (not including Columbia).

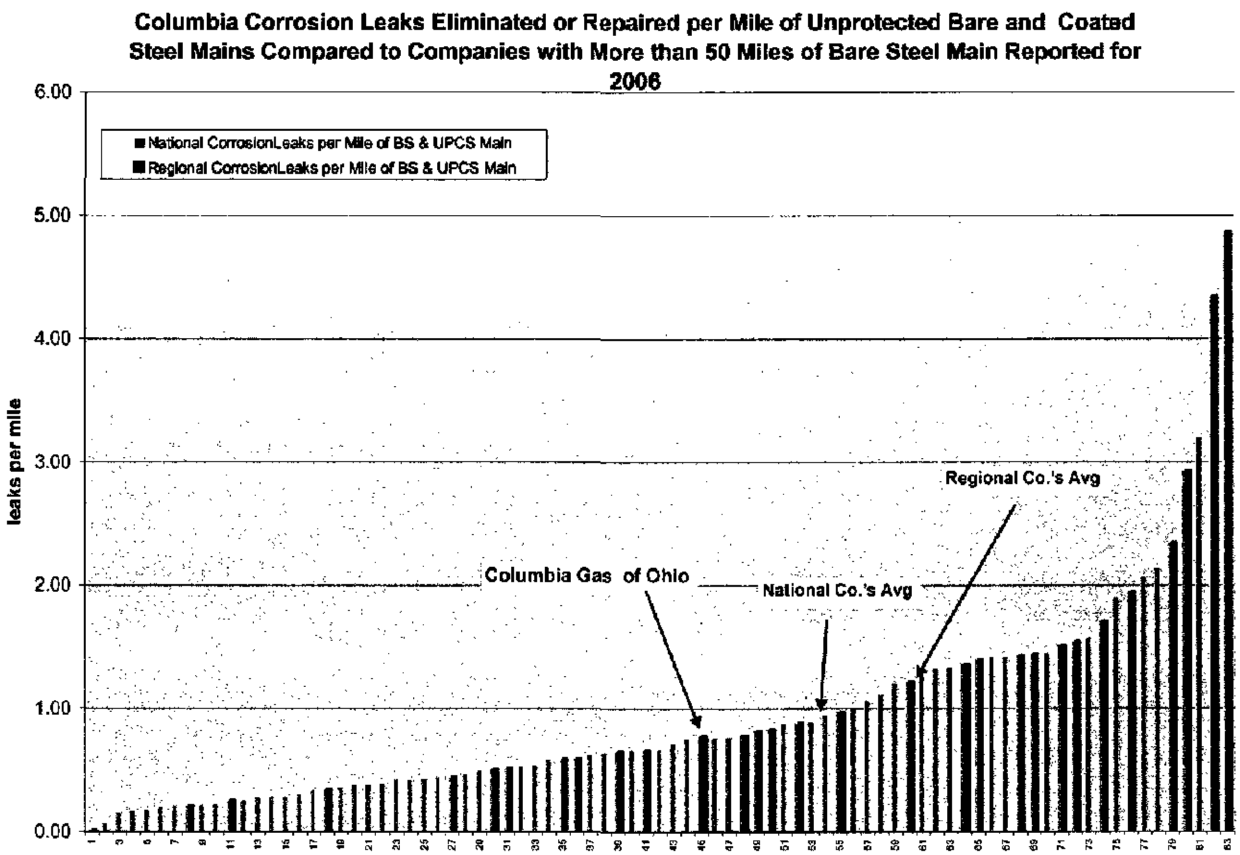

Figure 8

9. Change in Columbia's corrosion leaks per mile of non-protected bare steel and coated steel – 1997- 2006

The plot of Columbia's corrosion leaks per mile of unprotected bare steel and coated steel main and the regional companies for the period 1997- 2006 is presented[3] in Figure 9.

It is apparent that the Company's corrosion leak rate per mile (0.76) appears favorable compared to the average of the corrosion leak rate for the regional companies. However if Columbia's corrosion leak rate was to simply rise to the level of the average leak rate for regional companies in 2006 (1.28), that would mean that the its annual corrosion leaks would increase from 2,820 to 4,755 leaks. This would be a 69% increase in the number of leaks.

Black & Veatch believes that such a higher level of leaks adds incremental risks to Columbia and the public. We support the Company's decision to begin an accelerated replacement program of its trouble prone mains to drive down the present corrosion leak rate of nearly 3,000 leaks per year and improve the safety and reliability of their system. Without an accelerated mains replacement program, we believe that the rate of corrosion leaks will increase.

Columbia has advised Black & Veatch of segments of mains that it has already replaced or are pending replacement that had experienced leak rates far in excess of the average annual corrosion leak rate (0.76 leaks per mile) for its entire system. This helps illustrate that Columbia's average leak rate will continue to rise if its aging trouble prone pipelines are not retired or replaced. It is Black & Veatch's opinion that action must be taken at this time to begin to accelerate the retirement or replacement of these mains.

[3] For 1997-2001 SEMCO data was excluded from the calculation due to it being a high end outlier.

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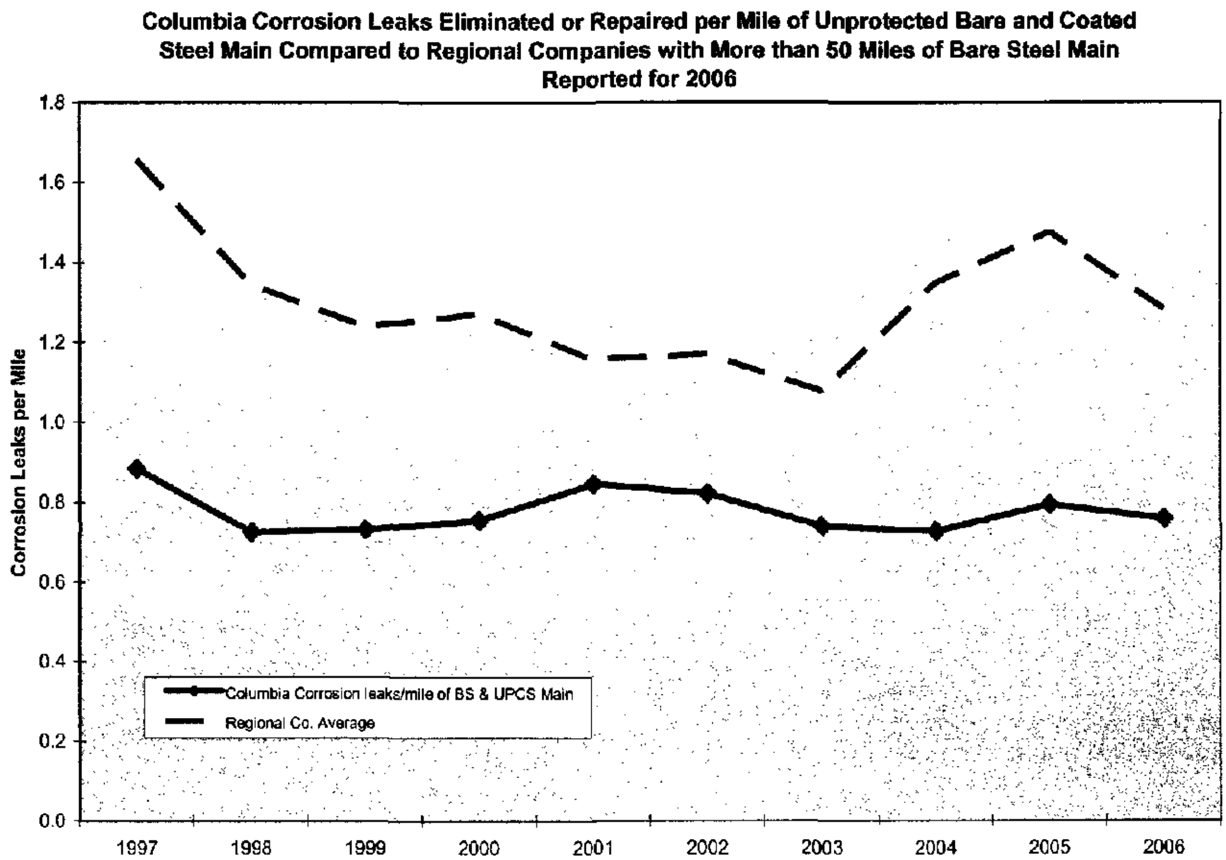

Figure 9

10. Pipeline corrosion - industry data

Black & Veatch's opinion is supported by our gas distribution industry experience and data. For example, the modes of failure and the mechanisms associated with bare steel corrosion are well understood by corrosion experts and documented in a number of texts on the topic. It is a known fact that bare steel pipe, buried in the earth where there is moisture in the soil and without cathodic protection, will corrode over time. This corrosion may occur over the entire surface of the pipe and it may take many years before the first single corrosion leak occurs. However, once the first leak on a pipeline segment occurs, there are other points on the pipe where it is loosing metal and where pits are becoming deeper and deeper due to corrosion. As the corrosion pitting continues and the pipes continue to loose metal, these pipes will experience additional leaks in a shorter and shorter timeframe as the corrosion pits completely breach the wall of the pipe. Eventually many additional points of corrosion may result in an unmanageable leak rate as the pipe becomes fragile and sometimes unrepairable.

This deterioration mentioned above is a function of time in the ground. This fact is evidenced by the fact that the DOT has not allowed the installation of bare steel for gas service since 1971. Furthermore, an early scientific reference regarding the failure rate of buried steel pipe was given in the book "Soil Corrosion and Pipe Line Protection" by Scott Ewing Ph.D. published in 1938. In the text the performance of the service pipes in the Philadelphia Gas Works System was plotted and showed that corrosion leak occurrences over time on bare steel pipe increased at an exponential rate. This graph is shown below in Figure 10. When this text was written the natural gas industry was still in its infancy and the high performance materials such as plastic and well coated and cathodically protected steel were not available or well understood.

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CORROSION IN DISTRIBUTION SYSTEMS CHAPTER IV

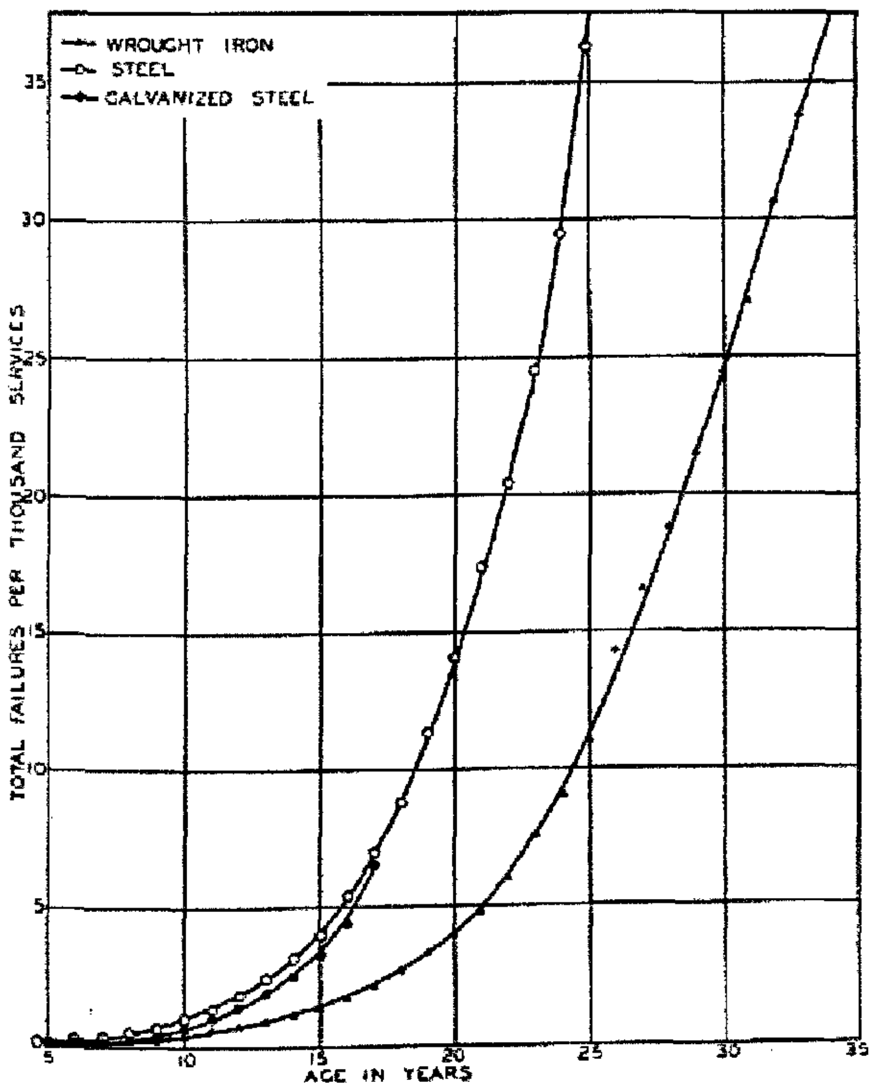

Fig. 7. Failure curves of house services in the Philadelphia Gas Works System.

Figure 10 - Chart from 1938 text showing exponential leak rates for bare steel pipe in gas service

This very same finding is corroborated today in more modern texts. One such text which is considered by many to be a foundational book for the study of corrosion is "Peabody's Control of Pipeline Corrosion" by A.W. Peabody, published by the National Association of Corrosion Engineers International, the Corrosion Society (Second Edition 2001). This text published more than 60 years after the Ewing text reaffirms the fact that leak incidents on bare pipe will occur at an exponentially increasing rate. In the Peabody text this is shown as an example plotted on semi log paper. A copy of the graph used to describe this in the Peabody text (Figure 15.1 in Peabody) is shown in Figure 11 below.

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As can be seen on this graph, no leakage occurs during the initial life of the pipe (first leak occurred 4 years after placing the piping in service). Then, in the next 4 years, 1.5 new leaks occurred. Then, in the next 4 years, 4.5 new leaks occurred. Then, in the next 4 years, 11 new leaks occurred. This accelerating occurrence of leaks continues at a rate that places the cumulative leak count off the scale, past the 23rd year, with more than 100 cumulative leaks occurring. What is important to note is not that the leaks are occurring, but that they are occurring at an ever increasing frequency as a function of time.

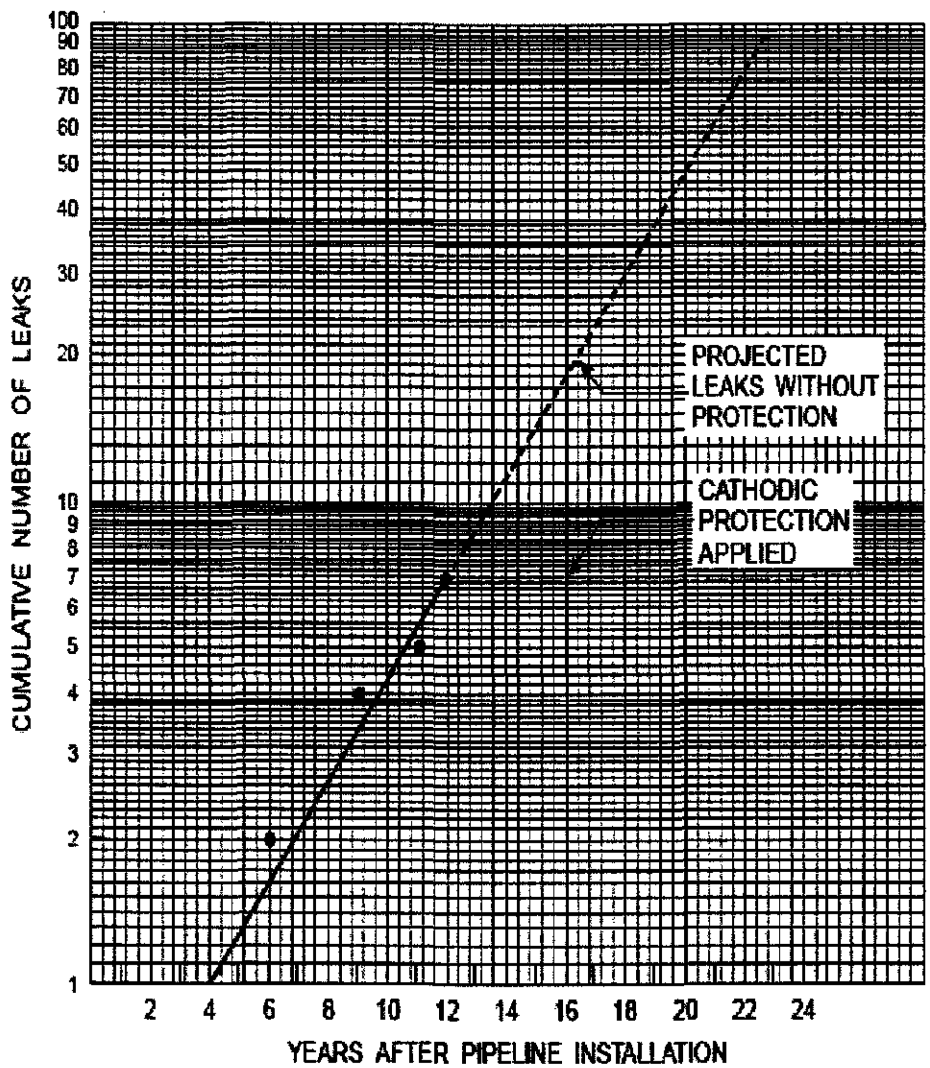


Figure 15.1 Cumulative number of leaks without CP.

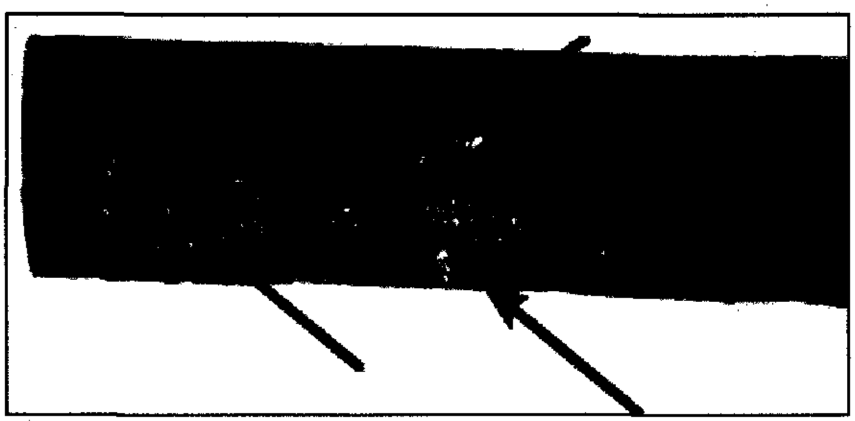
Figure 11 - Chart from 2001 text showing exponential leak rates for bare steel pipe in gas service.

This exponential growth of leak occurrences on bare steel pipe is scientifically documented as indicated in the text above. This exponential growth of leak occurrences on bare steel pipe is also well known by experienced gas system operators who perform bare steel repairs and find themselves installing leak repair sleeve after sleeve on sections of corroding pipe.

This ever increasing frequency of leak incidents is also intuitively evident based on the corrosion mechanisms. Intuitively speaking, the wall thickness of a pipe is undergoing continuous deterioration by corrosion. In some locations the deterioration is more aggressive than in other locations. Typically the wall thickness is many times thicker than needed to resist the hoop stresses caused by the pipeline pressure. Thus, when the first few corrosion leaks occur in a pipe segment, it is intuitive that many more future leaks are nearing their emergence as the corrosion pits become deeper and approach the point where they have fully breached the wall of the pipe and allow the gas to escape. In many cases although the wall thickness is penetrated at only a single point it can be seen that the entire pipe may have been degraded to the point where future leaks will occur at an ever increasing rate. This is visually obvious by viewing the piece of corroded pipe shown from the DOT OPS website in Figure 12. In this excerpt and picture, there may be only a few points of actual leakage, but as can be seen the pipe shows signs of distress along the entire wall thickness.

Corrosion is the deterioration of metal pipe. Corrosion is caused by a reaction between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Although corrosion cannot be eliminated, it can be substantially reduced with cathodic protection (see FIGURE III-1).

FIGURE III-1 BARE PIPE -NOT UNDER CATHODIC PROTECTION



An example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground. Operators should use either polyethylene pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Figure 12 - Excerpt from DOT OPS website
http://ops.dot.gov/regs/small_ng/Chapter3.htm

The following two photographs were provided by Columbia as additional illustrations of the degree to which corrosion can destroy the integrity of bare steel pipelines. In the first photo, when a section of bare steel main was cleaned of dirt and scale, it revealed a corrosion hole in the pipe that was approximately 5.5 inches in length (Figure 13). In the second photo, when a customer service line tee was cleaned of dirt and scale, it revealed significant corrosion over the entire pipe as well as a hole in the service (Figure 14).

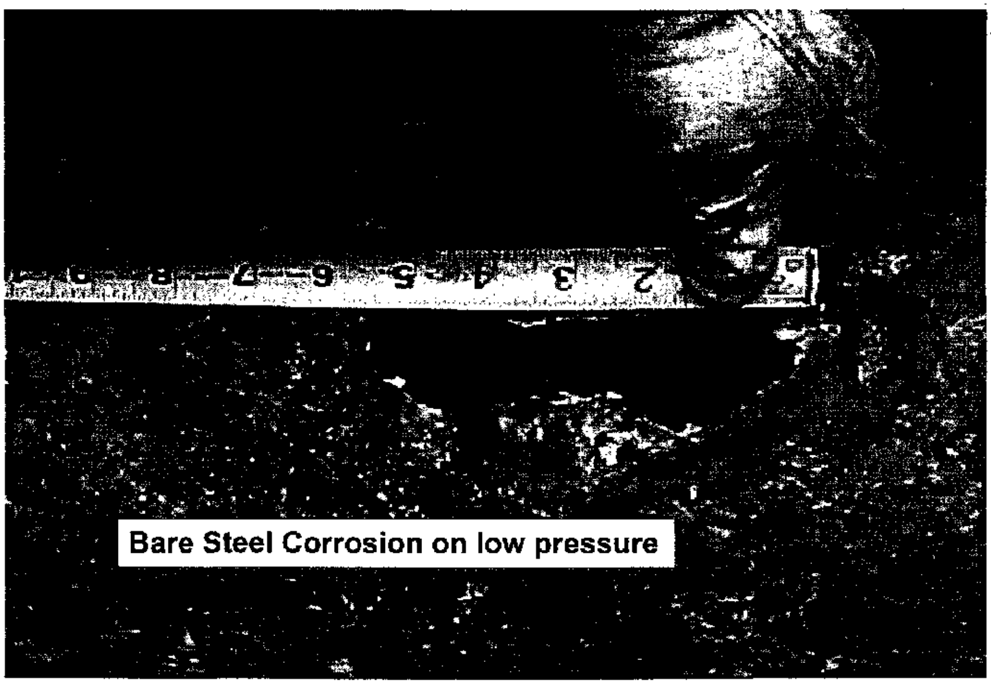


Figure 13

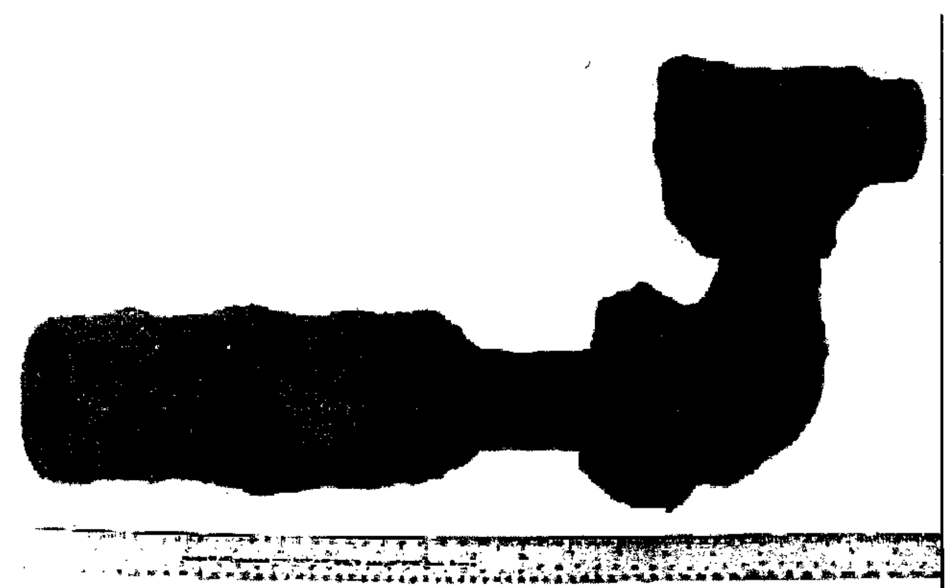


Figure 14

The issue that Columbia faces is not "if" it will need to replace its bare steel mains, but over what time frame it will need to replace mains to best serve the needs of its customers. With the clear understanding that Columbia's system is aging (with new corrosion pits approaching the point of leakage), and with the knowledge that the leak occurrence rates are a function of the number of years a main segment is exposed to a corrosive environment (the age of the mains), there are a number of scenarios that could be considered. For example:

Scenario 1 - Status Quo

In this scenario, Columbia may continue at its present rate of pipeline replacement. In 2006, the Company replaced 50.6 miles of bare steel mains. This rate of replacement may continue to work well for a period of time. However, it must be realized that nearly 2,100 miles of main was installed before 1940 and that an additional almost 3,000 miles of main were installed in the 10 year period of 1950 to 1959. This is shown in Figure 3. As discussed previously, at the Company's present replacement rate, it would take another 72 years to replace these mains. Even if Columbia made an effort to replace the oldest mains first, Columbia's late vintage of main installed in the 1950s would be over 120 years old before replacement occurred at this current rate.

When these main segments age to the point that they begin to experience a continuing increase in the number of corrosion leaks and a corresponding increase in the leaks per mile, this situation will challenge Columbia's ability to manage risk and to keep up with the necessary level of leak repairs. This problem is not unique to Columbia – other companies that have a very large inventory of bare steel pipe are faced with the same challenge. When greater amounts of pipe begin to experience a continuing increase in the number of corrosion leaks, the additional leaks increase the risk to the public and to the Company's employees, as well as increase the costs to remedy the problem. Black and Veatch does not recommend this approach.

Scenario 2 – Proactive

In this scenario, Columbia would replace its bare steel mains at a rate significantly greater than today, while remaining manageable beginning with the mains that are in the worst condition, as identified by Columbia management, using all of its decision making support tools.

Columbia's management has stated that it has determined the shortest manageable time frame to complete the necessary main replacements is 25 years. Under this scenario Columbia would strive to replace approximately three times the amount it replaced in 2006 (approximately 50 miles) or approximately 150 miles of bare steel per year. Black & Veatch believes that this rate of replacement is a reasonable expectation and would bring Columbia in line with the current nationwide average rate of replacement. Furthermore, if Columbia finds that it is unable to apply adequate cathodic protection to its coated steel mains that are currently without cathodic protection because they have deteriorated to a point beyond protecting, the Company will have to replace these mains with plastic or new coated steel.

This proactive approach would provide a planned mechanism to replace all of Columbia's aging, trouble prone pipe with mostly plastic, and in some instances, with cathodically protected coated steel pipe. In Black and Veatch's opinion, this is the most prudent scenario because it preserves the safety of the Company's customers while avoiding numerous repairs of the piping before its eventual replacement.

However, if during the planned 25 year replacement program Columbia observes that the rate of corrosion leaks per mile is increasing and becomes unmanageable, it may need to increase the rate of replacement of the troublesome mains. Furthermore, under this scenario the newest of the 1950-1959 vintage pipe would be over 70 years old before replacement. Black and Veatch views this scenario as being a prudent and responsible way to manage the need to replace these mains.

It should be noted that other companies in the same region as Columbia have also realized the need to replace their bare steel mains. Duke Energy Ohio had presented its case for the replacement of its bare steel to the PUCO and requested rate relief and the authorization to institute an Accelerated Mains Replacement Program ("AMRP") tracker. The PUCO approved the program and the tracker. The request by Duke Energy was for the replacement of all the bare steel and cast iron main over a 10 year period. According to Gary Hebbeler's recent testimony on behalf of Duke Energy, in Case No. 07-589-GA-AIR, it has replaced 559 miles of cast iron and bare steel during the period 2001-2006. This equates to 93 miles per year compared to Columbia's plan to replace approximately 150 miles of bare steel per year for the next 25 years. While Duke Energy's 10 year replacement program may appear to be more aggressive than Columbia's 25 year plan, one must recognize that for the Company to replace its bare steel mains in 10 years, it would need to replace 366 miles per year. This is approximately 4 times the amount of miles that Duke Energy replaced each year. In our opinion it is not reasonable to plan for a replacement program of a higher magnitude than Columbia is instituting as long as its corrosion leak levels remain under control. As it is, the Company is planning to replace 150 miles of bare steel per year which will be a resource challenge. Duke Energy's replacement program, as testified by Mr. Hebbeler, has resulted in a significant reduction of leaks from 6,223 leaks in 2002 to 4,196 leaks in 2006 when the replacement program was only 48% complete. Black and Veatch would expect similar results for Columbia as its program is implemented.

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11. Columbia's Year end backlog of leaks pending repair - 2006

Each distribution operator is also required by the DOT to also report the number of leaks awaiting repairs at the end of each year.

Figure 15 compares Columbia leak backlog to all companies with more that 50 miles of bare steel main. In 2006, the Company had the fifth highest level of leaks in backlog pending repair and was above both the national and regional averages of leaks in backlog pending repair at year end. This large number of leaks pending repairs is a direct function of the large amount of bare steel inventory, its associated level of corrosion leaks, and the Company resources available to repair or replace the offending sections of main. As sections of main are replaced, the replacement will not only reduce the production of new leaks, but it will also eliminate the existing leak backlog associated with those main segments.

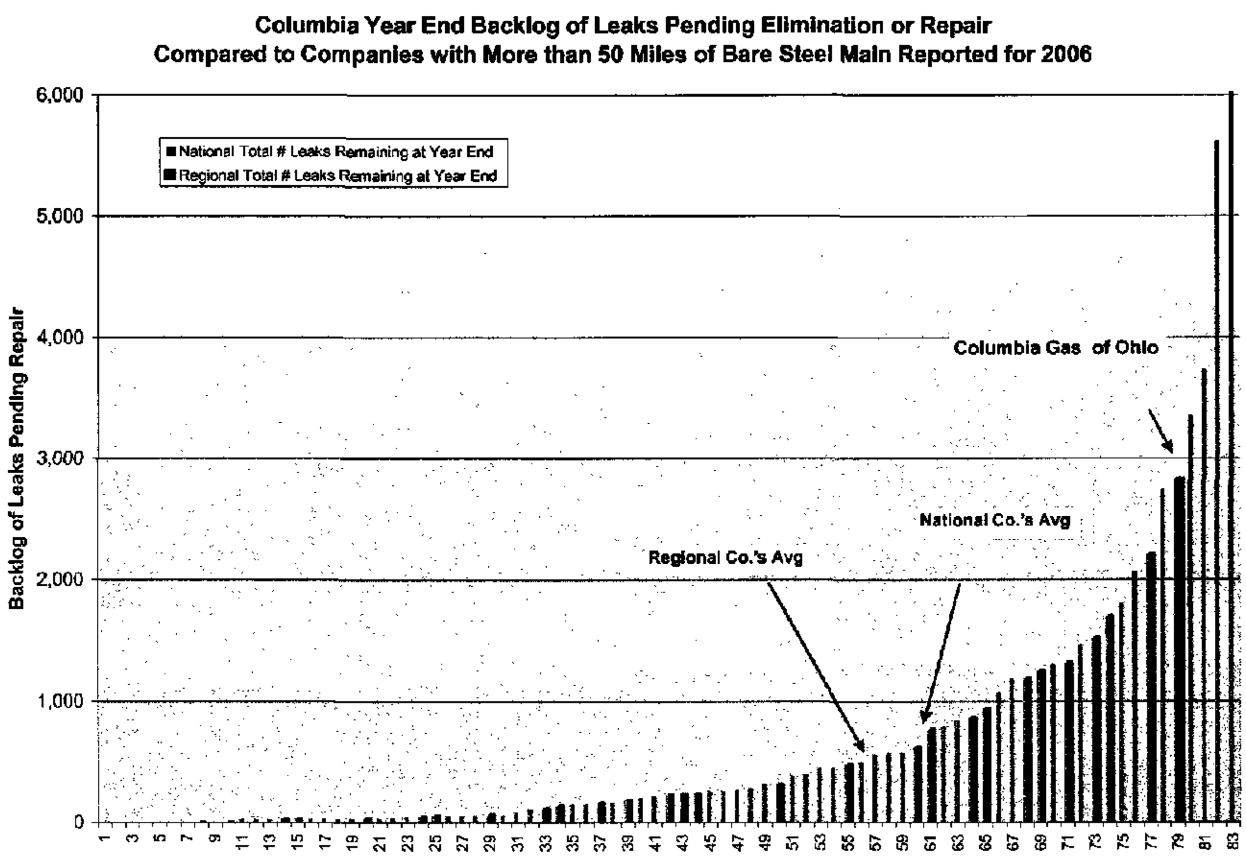

Figure 15

12. Comparison of leak backlog pending repair at year end to corrosion leaks - 1997-2006

Columbia has been able through its operating practices to maintain a relatively flat level of both corrosion leaks eliminated or repaired and the level of leaks in backlog at the end of the year. This is illustrated in Figure 16. Maintaining a close watch on these two elements helps provide an indicator as to any changes in direction of system leaks.

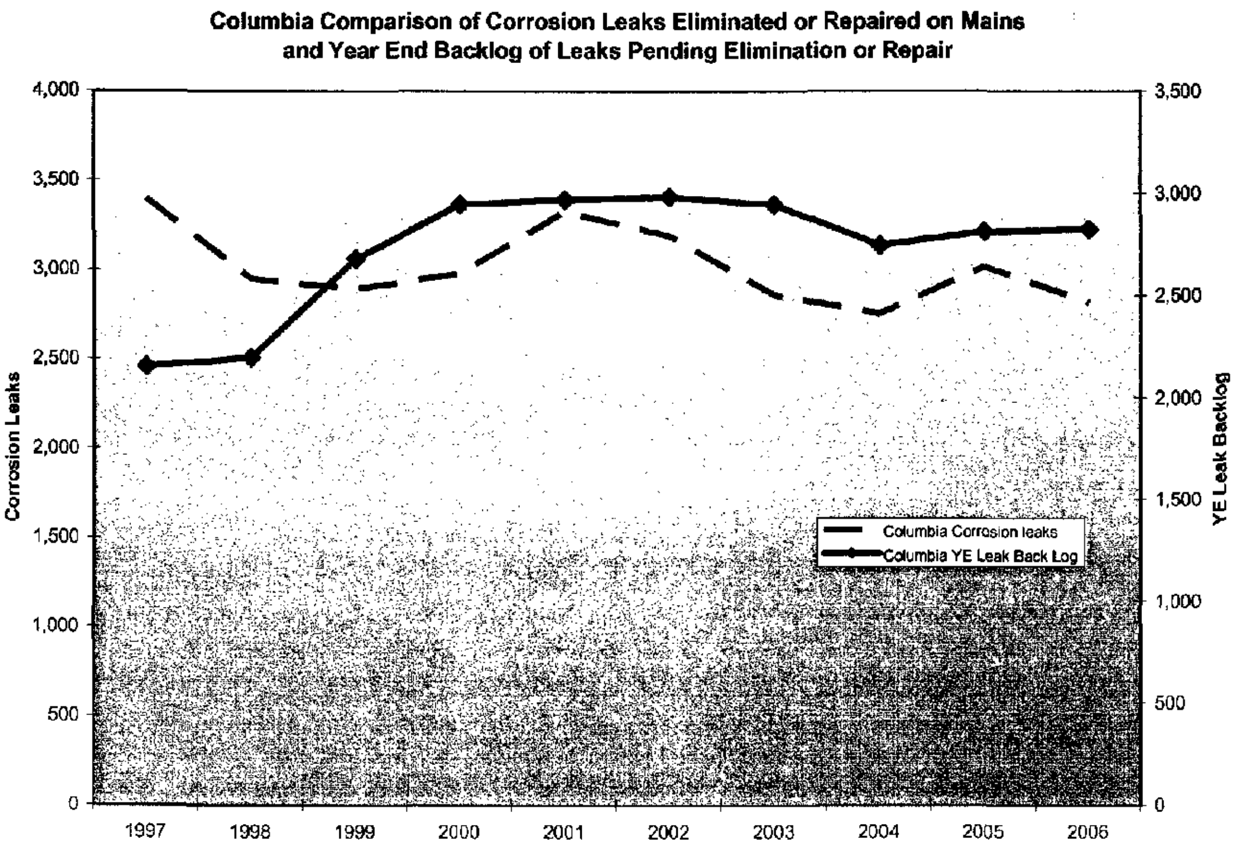

Figure 16

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13. Columbia's services by material type

Figure 17 illustrates Columbia's inventory of services by material type. In 2006, it reported having 171,589 bare steel (13% of all services) and 2,413 non-protected coated steel (0.2%) services remaining in its system.

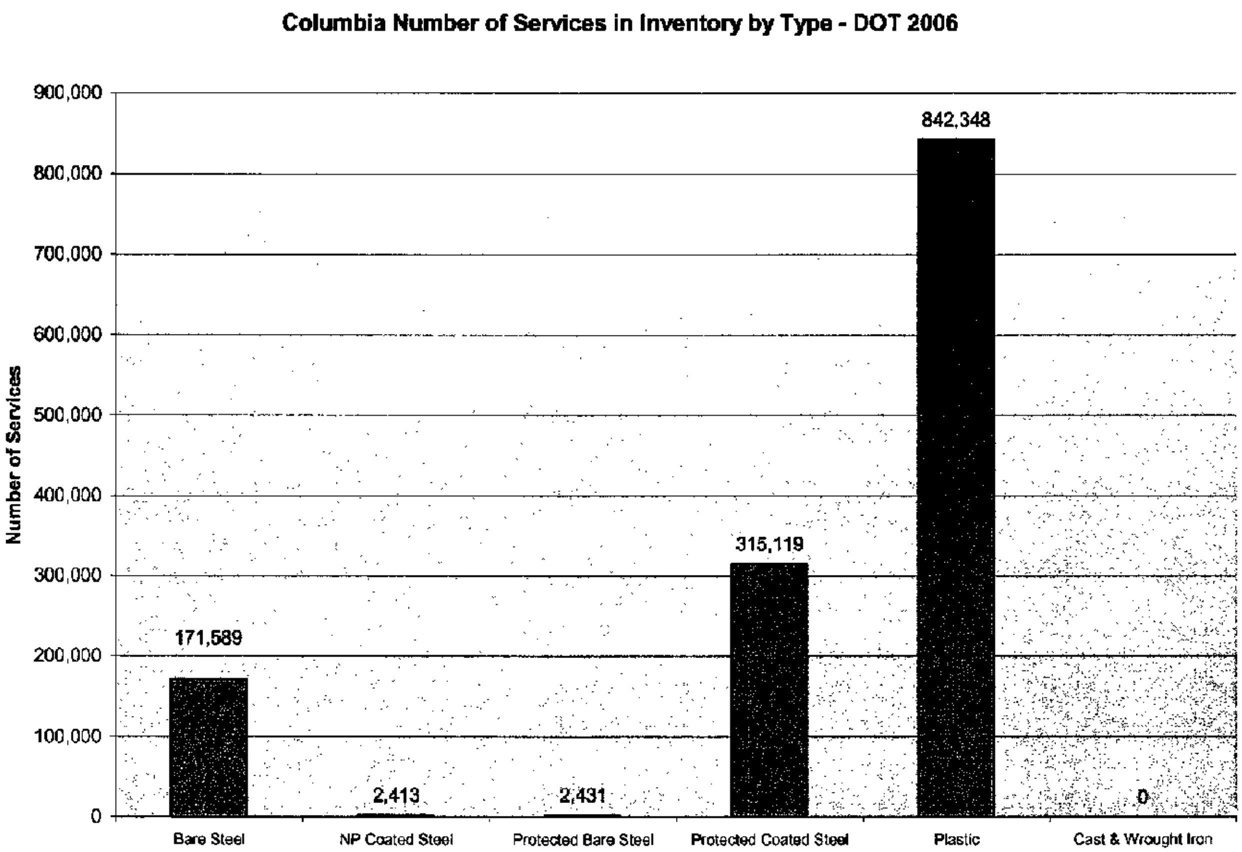

Figure 17

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14. Columbia's number of bare steel services comparison - 2006

When comparing the number of bare steel services among the companies reporting having more than 50 miles of bare steel main in 2006, Columbia has the fourth highest number of bare steel services (171,589) of all of the companies. This is reasonable for a company with such a large inventory of bare steel mains. This is illustrated in Figure 18.

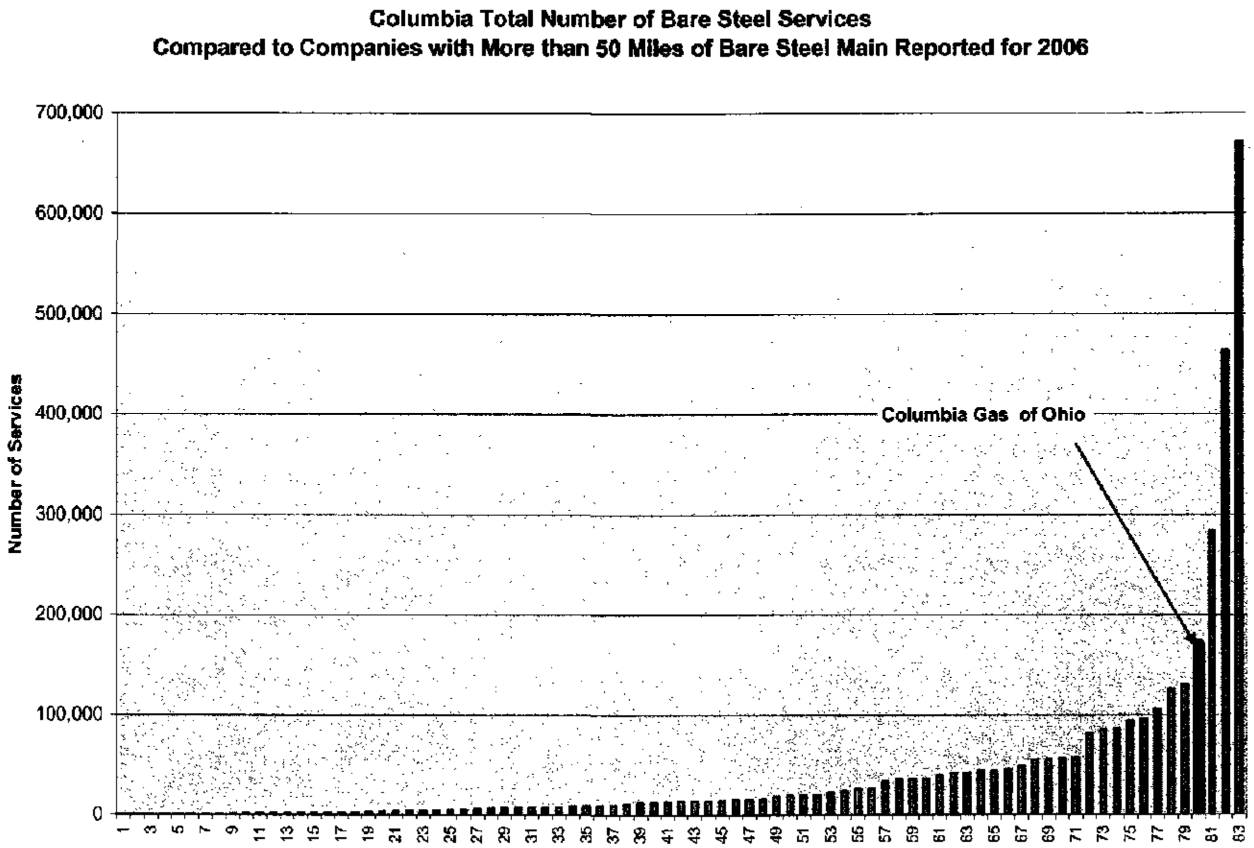

Figure 18

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15. Change in Columbia's corrosion leaks on services - 1997 - 2006

Similar to corrosion leaks on non-protected bare and coated steel mains, Columbia is experiencing a higher number of corrosion leaks on services compared to the average of regional companies. We believe that this high number of corrosion leaks on services is directly related to Columbia's large inventory of non-protected bare and coated steel services. In 2006 there were 1,673 corrosion leaks on services ranking Columbia as having the twelfth highest number of corrosion leaks on services in the nation.

Figure 19 illustrates that while the number of annual corrosion leaks eliminated or repaired on services are moving in the right direction (decreasing), they are still significantly higher than the average of regional companies.

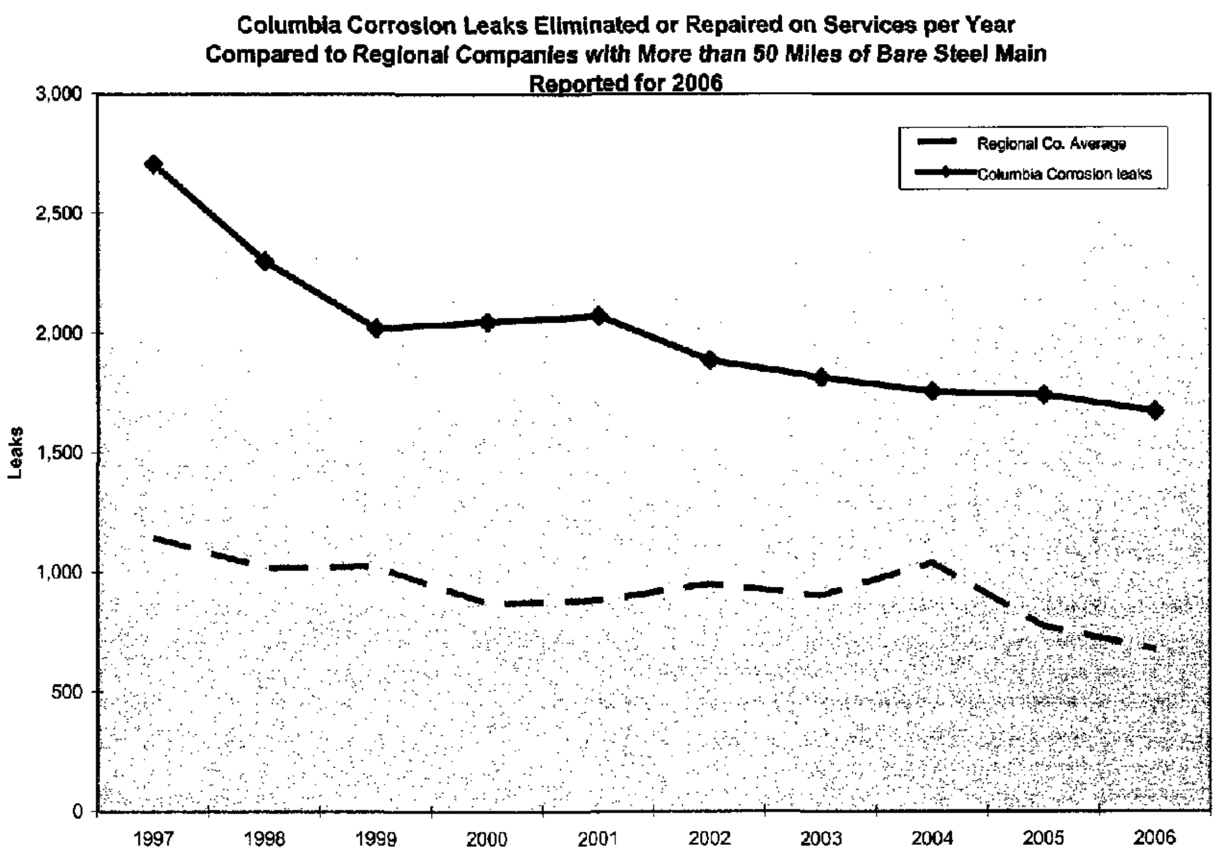

Figure 19

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16. Columbia's corrosion leaks per 1,000 unprotected bare and coated steel services comparison - 2006

Figure 20 illustrates a comparison of the measure of corrosion leaks per 1,000 bare and non-protected steel services among companies with more than 50 miles of bare steel mains.

While Columbia's ranking in this metric is favorable to the other national and regional companies, continued improvement is required to further reduce the number of corrosion related leaks from the 2006 level of 1,673.

As part of the Company's efforts to reduce service related leaks, Black and Veatch believes that Columbia should follow the industry's best practices of replacing such services at the time the bare and non-protected coated steel mains are replaced. In addition, it may be necessary to replace existing coated steel services, if field supervision determines this to be prudent due to the condition of the existing coated steel service. For such cases a plastic insert would typically be the method of replacement. There is a significant benefit to the gas customers in the efficiency of gas service leak repair when replacement of bare steel or otherwise deteriorated services occurs at the time of main replacement. In doing this there is an economic advantage, since this work is completed by crews already on site under the same work permit and without the need to perform the very costly leak investigation.

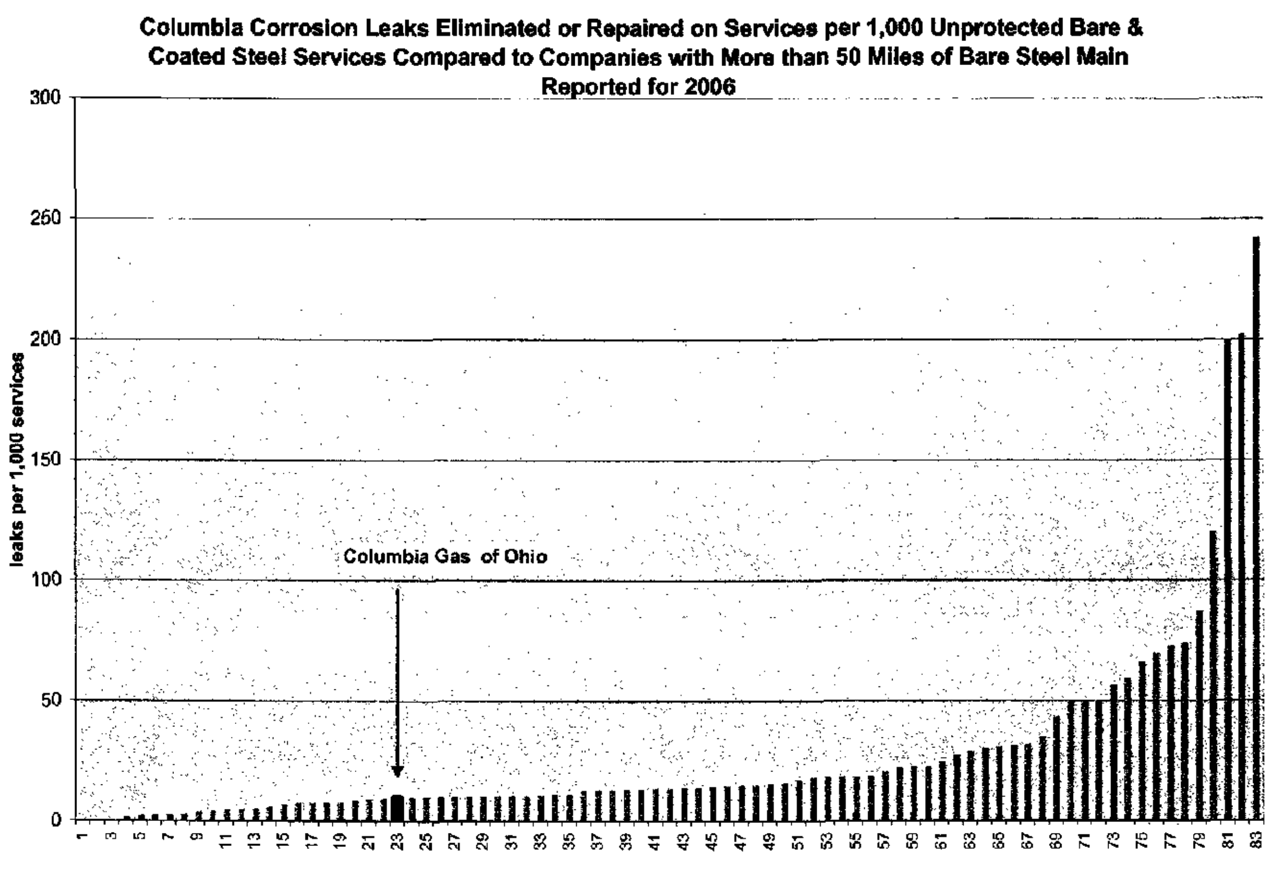

Figure 20

17. Columbia's cast and wrought iron mains

The natural gas industry typically includes cast and wrought iron mains among its list of trouble prone main materials, along with bare steel mains. These mains are among the oldest mains remaining in distribution systems dating back to before the 1900's and are a problem for distribution operators because of the way they leak. Just like with bare steel mains, the DOT no longer permits these mains to be installed.

Cast iron main sections are typically joined together by jute and lead caulking at its bell and spigot joints. Over time these joints become dried out and due to the flexing of the pipe that may occur due to traffic vibration, seasonal weather, and construction activities, these joints eventually leak. Of greater concern is the fact that cast iron mains are more susceptible to cracks or main breaks due to earth movement. Such breaks are of a major concern due to the amount of gas that may be released in such circumstances. Unlike a corrosion leak that starts small, often a cracked main may leak at such a high rate that it can quickly saturate the area around the leak with natural gas and it may enter underground passageways to homes or other confined spaces such as underground utility vaults and sewers. Cast iron main breaks are particularly a concern during very cold temperatures when frost may cause additional stresses on these mains and when frost may also make the earth's surface an impermeable surface unable to allow the gas to vent out safely. The inability of the gas to safely escape increases the risk to near-by residents as this gas follows the path of least resistance which all too often is the basement of the house. Cast iron is capable of corroding under the right soil conditions, but is much more likely to leak at joints or crack in a brittle failure mode. Wrought iron, while less brittle than cast iron main, is subject to corrosion. A viewing of the chart provided in Figure 11 shows the corrosion of wrought iron as being similar to bare steel in its exponential leak rate growth. It too is part of the family of poor performers that needs replacement.

Regarding the replacement of cast and wrought iron mains, nearly 60% of the cast iron and wrought iron mains are 4 inch or smaller in size. This is particularly concerning as smaller diameter mains experience higher stresses when placed under bending moments due to forces such higher stresses pose an increased risk of cracking and corrosion. This will need to be considered when assessing which mains need to be replaced first.

As illustrated previously in Figure 1, Columbia has 280 miles of cast and wrought iron mains in its distribution system. It is Black & Veatch's opinion that similar to the bare steel mains, these mains should be also targeted for replacement under the Company's proposed 25 year replacement program. Such replacements should be prioritized based on the analysis of data using all of the tools available to Columbia's management. The inclusion of these cast iron mains, along with the Company's bare steel and non-cathodically coated steel mains into Columbia's 25 year replacement program, would result in the need to replace approximately 160 miles of main per year.

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Conclusions

Throughout this report, Black & Veatch has compared Columbia's bare and coated steel piping, using various measures, against other national and regional distribution operating companies that reported to DOT having more than 50 miles of bare steel mains in their systems in 2006.

Our key findings and opinions are summarized as follows:

1) Of the 1,383 distribution gas operating companies reporting to the DOT in 2006, Columbia has the greatest amount of bare steel mains remaining in its distribution system. At the end of 2006, Columbia reported having 3,663 miles of bare steel, 52 miles of unprotected coated steel and 280 miles of cast or wrought iron remaining in its distribution system. Columbia's inventory of bare and unprotected coated steel main is 19% of its total inventory of mains.

2) Columbia had the third highest number of corrosion leaks on mains in the nation in 2006 with 2,820 corrosion leaks. These leaks were predominately on its bare steel mains. Bare steel is known in the gas industry as a trouble prone piping material with regard to corrosion leakage over time as evidenced by the fact that the DOT no longer allows it for new installations. In addition it is often difficult to cost effectively protect such mains via cathodic protection methods. Unprotected coated steel mains are also susceptible to high and growing leak rates, however, coated steel mains can often be brought under effective cathodic protection (provided the integrity of the pipe has not deteriorated too far).

3) The data also shows that even with this high number of corrosion leaks on mains per year, Columbia maintained a corrosion leaks per mile of bare and non-protected coated steel mains rate that was lower than the average rate of regional companies. We believe that the Company's past ability to maintain a favorable corrosion leak rate compared to the region was based on its sound operating practices and experience with bare steel mains. However, if the Columbia's corrosion leak rate (0.76) was to simply rise to the level of the average leak rate for regional companies in 2006 (1.28), that would mean that its annual corrosion leaks would increase from 2,820 to 4,755 leaks (a 69% increase). A 69% increase in leaks would create additional safety risks for the public and Columbia's employees, as well as create a serious leak management challenge for the Company. It is our opinion that the focus of Columbia's efforts must be towards prioritizing the worst mains for replacement first and accelerating the replacement of these trouble prone mains before the leak rate gets out of hand. Without such an accelerated replacement effort it is our opinion that Columbia will face the risks associated with an ever increasing number of corrosion leaks.

4) In 2006 Columbia replaced 50.6 miles its bare steel mains at a rate of approximately 1.4% per year as compared to the national average replacement rate of 3.7% per year. At the present Columbia replacement rate, it would take the Company 72 years to eliminate its problematic bare steel mains compared to 26 years for the nation as a whole (not including Columbia). Columbia proposed accelerated replacement program (25 years) is in line with the national average. As the company with the largest amount of bare steel and the third

highest number of corrosion leaks on mains in the nation, Black and Veatch believes that such action is prudent and reasonable.

5) Based on the data comparisons completed by Black & Veatch and its interviews with Columbia operating staff, regarding the management of its corrosion leaks, the Company has been a good steward of it gas system as evidenced by its ability to manage its corrosion leakage rates thus far. Columbia's management believes, and Black and Veatch concurs, that in order to continue to be a good steward of this gas system, a systematic accelerated replacement of the problematic mains is required.

6) Cast iron mains, while less prone to corrosion leakage, are also poor performers due to its joining methods. Cast iron sections of pipe are typically joined together with calked lead and jute bell and spigot joints which leak over time. In addition, cast iron can leak because of its brittle failure mode that can result in sudden and serious leakage. Nearly 60% of the cast and wrought iron main is 4 inch or less in diameter. Such small mains experience higher stresses when placed under bending moments due to soil loadings. Such higher stresses pose an increased risk of cracking and corrosion.

7) More than half of Columbia's bare steel and cast or wrought iron mains were installed before 1940. They have been exposed to external corrosion elements for over 68 years. The remainder is of the pre 1959 vintage which would be between 48 to 68 years old today.

8) Corrosion experts (e.g., Peabody) have documented the exponential growth of corrosion leaks on bare steel as a function of time. This exponential growth rate begins after the first leak in a main segment occurs. A gas system with bare steel mains may be exposed to an acceleration of leakage incidents as its system ages. If a gas system has a relatively small amount of bare steel, this accelerated leak rate growth can be managed via a short time frame (ten years) mains replacement program. In the case of Columbia, with nearly 4,000 miles of bare steel, cast and wrought iron mains, an increase in its corrosion leak rate could not be efficiently mitigated in a short time frame. Hence, now is the time to begin an accelerated mains replacement program.

9) Columbia has the fourth highest number of bare steel services (171,589 services) among all companies reporting to the DOT with more than 50 miles of bare steel main. In 2006 Columbia had 1,673 corrosion leaks on services ranking it as having the twelfth highest number of corrosion leaks on services among all of the companies in the nation reporting to the DOT. As part of the Company's effort to reduce service related leaks, Black and Veatch believes that Columbia should follow the industry's best practices of replacing such services at the time the bare and non-protected coated steel mains are replaced. Furthermore, there is a significant benefit to the gas customers in the efficiency of gas service leak repair when replacement of bare steel or otherwise deteriorated services occurs at the time of main replacement. In doing this there is an economic advantage, since this work is completed by crews already on site under the same work permit and without the need to perform the very costly leak investigation.

10) In 2006, Columbia had the fifth highest level of leaks in backlog pending repair (among companies with more than 50 miles of bare steel main in their system), and was above both the national and regional average of leaks in backlog pending repair at year end. This large number of leaks pending repair is a direct function of the large amount of bare steel inventory, its associated level of corrosion leaks and the company resources available to repair or replace the offending sections of mains. As sections of main are replaced, the replacement will not only reduce the production of new leaks, but it will also eliminate the existing leak backlog associated with those main segments.

In addition to the customer safety and system reliability benefits noted throughout this report, a well planned accelerated main replacement program would have a host of qualitative benefits for the public such as fewer unplanned disruptions to traffic on roads for emergency gas leak repairs, and improved coordination with local town and village governments. Although these quality of life benefits are dwarfed by the safety and reliability benefits, it is Black & Veatch opinion that prudent utility operators need to manage in a manner that protects the customer, assures the integrity of the gas system and does not inconsiderately inconvenience the customer's quality of life.

Black & Veatch recognizes and supports Columbia's concern for the safety of its customers and employees and its desire to be a good steward of the gas system it operates.

Black & Veatch recommends that the PUCO support and approve the implementation of Columbia's proposed accelerated mains replacement program.

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Appendix A

List of 83 Companies Meeting the Selection Criteria within the National Sample

ALABAMA GAS CORPORATION
AQUILA NETWORKS (KANSAS)
AQUILA NETWORKS (NEBRASKA)
ARKANSAS WESTERN GAS COMPANY
ATLANTA GAS LIGHT
ATMOS ENERGY - WEST TEXAS DIVISION
ATMOS ENERGY CORP., MID-TEX DIVISION
ATMOS ENERGY CORPORATION, COLORADO KANSAS DIVISION
ATMOST ENERGY CORPORATION - KY/MID STATES DIVISION
ATMOST ENERGY CORPORATION - KY/MID STATES DIVISION
BALTIMORE GAS & ELECTRIC COMPANY
BAY STATE GAS COMPANY
CENTERPOINT ENERGY
CENTERPOINT ENERGY RESOURCES CORP.,D/B/A CENTERPOINT ENERGY MINNESOTA GAS
CENTRAL FLORIDA GAS, (WINTER HAVEN)
CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CHARTIERS NATURAL GAS COMPANY, INC.
CHESAPEAKE UTILITIES CORPORATION MARYLAND GAS DIVISION
CLEARWATER GAS SYSTEM
COLUMBIA GAS OF KENTUCKY
COLUMBIA GAS OF MARYLAND
COLUMBIA GAS OF OHIO
COLUMBIA GAS OF PENNSYLVANIA
COLUMBIA GAS OF VIRGINIA
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
CONSUMERS ENERGY COMPANY
CONSUMERS GAS UTILITY COMPANY
CORNING NATURAL GAS CORPORATION
DELTA NATURAL GAS COMPANY, INC
DOMINION EAST OHIO
DUKE ENERGY OHIO, INC.
ENERGY SERVICES OF PENSACOLA
EQUITABLE GAS COMPANY
FLORIDA PUBLIC UTILITIES
FLORIDA PUBLIC UTILITIES
HOPE GAS INC, DBA DOMINION HOPE
INDIANA GAS COMPANY, INC.
KANSAS GAS SERVICE
KANSAS GAS SERVICE
KEYSPAN ENERGY DELIVERY - BOSTON GAS
KEYSPAN ENERGY DELIVERY - COLONIAL CAPE
KEYSPAN ENERGY DELIVERY - LONG ISLAND
KEYSPAN ENERGY DELIVERY- NEW YORK CITY
LANCASTER MUNICIPAL GAS DEPT.

LOUISVILLE GAS & ELECTRIC COMPANY
MICHIGAN CONSOLIDATED GAS COMPANY
MOUNTAINEER GAS COMPANY
NATIONAL FUEL GAS DISTRIBUTION CORP - NY
NATIONAL FUEL GAS DISTRIBUTION CORP - PA
NATIONAL GAS & OIL COOPERATIVE
NATIONAL GRID USA
NATIONAL GRID USA (RHODE ISLAND)
NEW ENGLAND GAS COMPANY - FALL RIVER
NEW JERSEY NATURAL GAS
NEW YORK STATE ELECTRIC & GAS
NICOR GAS
NORTHERN INDIANA PUBLIC SERVICE COMPANY
NSTAR GAS COMPANY
OKLAHOMA NATURAL GAS COMPANY
ORANGE & ROCKLAND UTILITIES
PACIFIC GAS & ELECTRIC COMPANY
PECO ENERGY COMPANY
PPL GAS UTILITIES CORPORATION
PUBLIC SERVICE COMPANY OF COLORADO
PUBLIC SERVICE ELECTRIC & GAS COMPANY
PUGET SOUND ENERGY
ROCHESTER GAS AND ELECTRIC CORP.
SEMCO ENERGY GAS COMPANY
SOUTH JERSEY GAS COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
SOUTHERN CONNECTICUT GAS COMPANY
SOUTHERN INDIANA GAS & ELECTRIC COMPANY
SUBURBAN NATURAL GAS COMPANY
T. W. PHILLIPS GAS AND OIL CO.
TECO PEOPLES GAS
TEXAS GAS SERVICE COMPANY
THE GAS COMPANY, LLC
THE PEOPLES NATURAL GAS COMPANY DBA DOMINION PEOPLES
UGI PENN NATURAL GAS
UGI UTILITIES, INC.
VECTREN ENERGY DELIVERY OF OHIO
WASHINGTON GAS LIGHT COMPANY
YANKEE GAS SERVICES COMPANY

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Appendix B

List of 30 Companies Meeting the Selection Criteria within the Regional Sample

ATMOST ENERGY CORPORATION - KY/MID STATES DIVISION
CHARTIERS NATURAL GAS COMPANY, INC.
COLUMBIA GAS OF KENTUCKY
COLUMBIA GAS OF OHIO
COLUMBIA GAS OF PENNSYLVANIA
CONSUMERS ENERGY COMPANY
CONSUMERS GAS UTILITY COMPANY
DELTA NATURAL GAS COMPANY, INC
DOMINION EAST OHIO
DUKE ENERGY OHIO, INC.
EQUITABLE GAS COMPANY
HOPE GAS INC, DBA DOMINION HOPE
INDIANA GAS COMPANY, INC.
LANCASTER MUNICIPAL GAS DEPT.
LOUISVILLE GAS & ELECTRIC COMPANY
MICHIGAN CONSOLIDATED GAS COMPANY
MOUNTAINEER GAS COMPANY
NATIONAL FUEL GAS DISTRIBUTION CORP - PA
NATIONAL GAS & OIL COOPERATIVE
NORTHERN INDIANA PUBLIC SERVICE COMPANY
PECO ENERGY COMPANY
PPL GAS UTILITIES CORPORATION
SEMCO ENERGY GAS COMPANY
SOUTHERN INDIANA GAS & ELECTRIC COMPANY
SUBURBAN NATURAL GAS COMPANY
T. W. PHILLIPS GAS AND OIL CO.
THE PEOPLES NATURAL GAS COMPANY DBA DOMINION PEOPLES
UGI PENN NATURAL GAS
UGI UTILITIES, INC.
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