COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 01 2009

PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT OF GAS RATES OF COLUMBIA GAS OF KENTUCKY, INC.	)))	CASE NO. 2009-00141

VOLUME 7

DIRECT TESTIMONY

Columbia Gas of Kentucky
Case No. 2009-00141
Table of Contents
Volume 7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia	)	
Gas of Kentucky, Inc.	)	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF HERBERT A. MILLER, JR. ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
Email: dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF HERBERT A. MILLER, JR.

Q: Please state your name and business address.

A: My name is Herbert A. Miller, Jr. and my business address is 2001 Mercer Road, Lexington, KY, 40511.

Q: What is your current position and what are your current responsibilities?

A: I am currently the President of Columbia Gas of Kentucky, Inc. ("Columbia", or the "Company"). In this capacity, I am the corporate officer responsible for the leadership of Columbia, including oversight of regulatory matters, governmental affairs, external affairs, local customer relations and corporate policies.

Q: What is your educational background?

A: I received a B.A. degree from the University of Kentucky in 1972 and a Juris Doctor degree from the University of Kentucky College of Law in 1976.

Q: Please describe your employment history?

A: On September 1, 2006, I became President of Columbia Gas of Kentucky, Inc. From 1998 until that time, I was the Vice-President and Corporate Counsel of Kentucky-American Water Company and Associate Regional Counsel for the Southeast Region of the American Water Services Company, Inc. In those positions I was responsible for the legal and regulatory affairs for the subsidiaries and operations of the American Water Company in Kentucky, Tennessee and Georgia.

From 1993 to 1998, I practiced law as a partner in what is now the firm of Stoll Keenon Ogden in Lexington, Kentucky. My clients were primarily financial institutions, utilities, real estate developers, governmental entities and non-profit organizations.

During this time period I also served as an adjunct professor at the University of Kentucky College of Business and Economics teaching classes in the *Regulatory and Ethical Environment of Business*.

From 1980 until 1993 I was the Senior Vice-President, General Counsel and Corporate Secretary of First Security Corporation, a multi-bank holding company headquartered in Lexington, Kentucky. In this position, I managed the legal, regulatory compliance and loss control departments and supervised the Securities and Exchange Commission ("SEC") reporting and disclosure functions.

From 1977 to 1980 I served as Corporate Counsel for the Lexington-Fayette Urban County Government and from 1976 to 1977 was an attorney in the office of General Counsel of the United States Customs Service in Washington, D.C.

Q: Have you previously testified before the Kentucky Public Service Commission or any other Kentucky regulatory commissions?

A: I filed testimony and appeared before this Commission in Columbia's last rate proceeding in Case Number 2007-00008. I have also filed regulatory reports, submitted responses to regulatory inquiries and appeared as counsel before the Commission in various cases and transactions.

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

A: The purpose of my testimony is to provide the Commission with a brief overview of this filing, Columbia's business activities and to discuss the objectives Columbia seeks to accomplish in this proceeding. I will also introduce the other witnesses who will be providing detailed testimony on various aspects of this filing.

Q: Please summarize the business of Columbia Gas of Kentucky.

A: Columbia Gas of Kentucky is one of nine natural gas local distribution companies in the NiSource family of companies and is headquartered in Lexington, Kentucky. Our 133 employees serve nearly 140,000 residential, commercial and industrial customers in 32 Kentucky counties through approximately 2,500 miles of main lines. This service area includes the communities of Ashland, Cynthiana, Frankfort, Georgetown, Greenup, Hindman, Inez, Irvine, Lexington, Louisa, Maysville, Midway, Mt. Sterling, Paris, South Shore, Versailles and Winchester, and all or parts of their surrounding counties.

NiSource Inc. ("NiSource") is headquartered in Merrillville, Indiana, and was created in 1998 by the merger of Northern Indiana Public Service Company and Bay State Gas Company. In 2000 NiSource merged with the Columbia Energy Group. It is a registered public utility holding company subject to the jurisdiction of the Federal Energy Regulatory Commission. The NiSource core operating companies engage in natural gas transmission, storage and distribution, as well as electric generation, transmission and distribution. Its natural gas distributions companies or divisions serve at retail over 3 million residential, commercial and industrial customers.

Q: Please summarize Columbia's major objectives in this proceeding.

A: Columbia's filing provides information necessary for the Commission to approve several initiatives Columbia believes are required for it to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers. To overcome its operating revenue deficiency, Columbia seeks an increase in operating revenues of $11,565,730 which represents a 7.03% increase from the 12-month period ending December 31, 2008. Columbia's request also includes adjustments in certain miscellaneous charges such as late charges and reconnection fees to adequately cover the costs associated with these activities and various organizational amendments to the tariff. Columbia is also including important regulatory concepts in this filing that will address important issues such as: (a) the recovery of its accelerated investment program to replace approximately 525 miles of its unprotected (bare) steel and cast iron infrastructure, and other types of lines that do not meet current material and construction standards as further described in the testimony of various Columbia witnesses listed below and elsewhere in this filing, (b) a rate design to decouple the recovery of fixed delivery costs from volume based rates using a gradual straight-fixed variable ("SFV") rate design, (c) the implementation of a demand-side management ("DSM") plan, (d) a mechanism for the reconciliation and recovery of Columbia's pension and other post-employment benefits ("OPEB") expenses, (f) the recovery of uncollectible expense pertaining to the calculated commodity cost of gas through a surcharge using the Estimated Gas Cost ("EGC") rate in effect at the time of billing and (g) two proposed service offerings called Price Protection Services ("PPS") and Negotiated Sales Services ("NSS") to allow customers to elect to pay for their natural gas on a fixed rate commodity basis over a fixed period of time. Each of these concepts will be summarized herein and described in more detail through the testimony of other Columbia witnesses in this proceeding and I refer you to that testimony.

Q: What was Columbia's overall return and return on equity during the historical test year ending December 31, 2008 for this case?

A: During the test year, and after non-base rate items, Columbia's overall rate of return was 5.23% and its return on equity was 6.09%.

Q: What overall return and return on equity does Mr. Paul Moul, Columbia's rate of return witness in this case, propose?

A: Mr. Moul proposes an overall rate of return of 9.00% and a rate of return on common equity of 12.25%. Please refer to Mr. Moul's testimony for a more detailed description of these proposals.

Q: When were Columbia's current base rates approved by this Commission?

A: Columbia's most recent base rates were approved by this Commission on August 29, 2007 in Case Number 2007-00008. In that case, the Commission approved a Joint Stipulation and Recommendation that the Company's operating revenues be increased by $7,250,000 or 4.58%. Prior to that, Columbia had not increased its base rates since 1996 when, as a result of Case Number 1994-179, it instituted a multi-year gradual increase in its base rates.

Q: What is the authorized rate of return on equity as approved by this Commission in Columbia's most recent rate case?

A: Columbia's authorized rate of return on equity is 10.50%.

Q: What is Columbia's history of rate cases?

A: Prior to 1996, I am advised Columbia was a frequent filer of rate cases. Between 1996 and 2007, with an increasingly competitive energy market, the Company employed significant cost control measures to meet its earnings objectives rather than filing rate cases. In Case Number 2002-00145, and as a result of the NiSource - Columbia Energy Group merger approval in Case Number 2000-129, the Company's base rates were actually decreased.

Q: Since its last rate case, how has Columbia improved its operations and services while taking cost control steps to avoid rate cases?

A: Columbia has continued to organize its operations more efficiently, continues to implement standardized policies and processes and invest in technology and infrastructure to improve service and improve costs. Columbia service technicians (who repair service lines, test meters, make customer connections and who test and light appliances) and our "plant" personnel (who install and repair mains, regulators and other underground facilities) live throughout our service territory, but are scheduled through computer-assisted centralized and coordinated systems that are used to predict, adjust and distribute employee workloads to address pipeline inspections, repair leaks, make appointments with customers and respond to emergencies. Many of the Company's higher grade level field employees are trained for both plant and service work which allows for more efficient allocation of human resources, improves service delivery and reduces overtime.

Columbia has completed the installation of mobile data terminals ("MDTs") in all of its plant and service trucks with the result that employees generally start their work day by going directly to the work site and can be re-directed in the field to respond to emergencies and other work. In 2009, Columbia employees began receiving Amber Alerts for missing children on every Columbia MDT.

In 2009 Columbia implemented a new procedure to "call ahead" for appointments to reduce the number of customer-requested service visits that resulted in the inability of the employee to access the customer's premises. Under this procedure, an agreed upon appointment schedule is made with a customer. On the day of the appointment, the Columbia employee telephones the customer ahead of the appointed time to confirm the arrival. If there is no answer after at least two attempts (including leaving messages), or if the customer reschedules the service call, the Columbia employee does not complete the call but proceeds to the next appointment. It is anticipated that this procedure will reduce the number and cost of the Company's CGI (Can't Get In) orders as well as meet the convenience of the customer by scheduling specific times for the service call.

New planning processes and strategies were developed and implemented in 2009 as a means to better forecast work load, understand cost drivers and manage impacts on cost performance. Planning and scheduling improvements will largely provide information that will help make more informed staffing decisions, identify cost savings opportunities and provide a framework with which to implement cost savings efforts and measure results.

Columbia is also implementing standardized procedures and policies that will aggregate the purchasing power of NiSource to drive down the cost of material and outside services purchases.

Q: What other steps has Columbia taken to promote quality control over its improved services?

A: Columbia retains the independent public opinion survey firm of Thoroughbred Research Group (formerly Wilkerson & Associates) to conduct random sample telephone interviews of customers who have interacted with our customer call center in order to rate their experience with both the call center personnel and our field personnel regarding skill, knowledge, courtesy, timeliness and overall performance. Poor responses are identified as "red flags" and are reviewed for possible trends or individual corrective action. Since arriving at Columbia in 2006, I have made it a priority to personally review the survey results, as well as other customer service issues, with our call center, the local supervisors and our field teams throughout our service territory.

Q: Has Columbia compromised service, safety or reliability while controlling costs?

A: Absolutely not. The safety of our customers, our employees and the general public are paramount and we will not compromise in this area. The Company's Accelerated Main Replacement Program ("AMRP") is an example of a forward looking plan to serve customers more safely in the future. I direct your attention to the testimony of Columbia witness Dave Mueller for an explanation of the Company's safety record.

Q: Please give a summary explanation of Columbia's Accelerated Main Replacement Program.

A: As described in greater detail by Columbia witness Dave Mueller, Columbia is facing accelerated deterioration of its bare steel, ineffectively coated steel, cathodically unprotected steel and cast iron mains; referred to as "Priority Pipe," and other infrastructure facilities. Generally speaking, bare steel, uncathodically coated steel, and ineffectively coated steel pipe are deteriorating at an accelerated rate due to the effects of corrosion, while cast iron mains are highly susceptible to failure due to ground movement and other environmental forces. These factors require the acceleration of the replacement of these facilities. In addition to the priority pipe, as described by Mr. Mueller, all metallic service lines and service lines that do not meet current material and construction standards are identified for replacement under the AMRP. Columbia has approximately 525 miles of main in its pipeline system that falls into this priority pipe category. Historical replacement schedules would result in a timetable of replacement of these unprotected facilities that would exceed 50 years and would be unacceptable. In 2008, Columbia began a comprehensive, accelerated program to invest nearly $210 million over 30 years to replace these facilities. In 2008, Columbia's AMRP resulted in the retirement of approximately 105,000 feet of high priority deteriorating mainline piping and 1,933 high priority deteriorating service lines. These projects occurred through our service territory in Boyd, Clark, Fayette, Franklin and Harrison counties.

Q: Provide a summary explanation of the AMRP recovery mechanism.

A: As described in greater detail by Columbia witness Judy Cooper, Columbia proposes a tracking mechanism to recover the costs of this system improvement on a timelier basis than provided by the traditional ratemaking process of repeated and more frequent rate cases. The cost recovery program is contained in the proposed tariffs in this filing.

Q: Is the Commission authorized to approve such a program and is there precedent for approval?

A: Yes. Kentucky Revised Statutes Chapter 278.509 states (in pertinent part) that "...the Commission may allow recovery of costs for the investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility. No recovery shall be allowed unless the costs shall have been deemed by the Commission to be fair, just and reasonable." The validity of this statute was upheld by the Kentucky Court of Appeals in *Kentucky Public Service Commission and Duke Energy Kentucky, Inc. v. Commonwealth of Kentucky, ex rel., Greg Stumbo* (Ky. App. Ct. 2007-CA-001635-MR dated November 7, 2008). The subject of that case was the Commission's approval of a request of The Union Light, Heat and Power Company (now Duke Energy Kentucky, Inc.) to replace 150 miles of unprotected steel and cast iron mains over a 10 year period. In that case, the Commission had approved the request in Case Number 2001-092 on January 31, 2002 for an initial three-year term and approved the continued use of the rider through the remaining years of its AMRP in Case Number 2005-00042 dated December 22, 2005.

Q: Has Columbia proposed the AMRP tracker before? If so, what was the result?

A: Yes, Columbia proposed an AMRP and recovery program in its last rate case in 2007. In the final stages of settlement, the Franklin Circuit Court issued an order in the *Duke Energy* case referenced above, invalidating KRS 287.509 and Columbia withdrew its proposed recovery mechanism from its case. Subsequently, the Kentucky Court of Appeals reversed the Franklin Circuit Court and upheld the validity of the authorizing statute. At the time of the circuit court ruling, Columbia stated its intention to proceed with the AMRP and acknowledged that without approval of its proposed recovery program, the Company would likely seek more frequent rate cases to recover the costs of the replacement program.

Q: What benefits exist from an AMRP?

A: The AMRP, including the recovery mechanism, will result in the replacement of roughly 20% of Columbia's gas distribution system which is not adequately protected at a faster rate than Columbia's process of identifying and replacing the worst performing pipe of the system each year. Please see the testimony of Columbia witness Dave Mueller for greater detail. Similar to the Duke Energy program, an additional benefit is the opportunity to move inside gas meters to outside locations at the same time that unprotected service pipelines are replaced. Columbia can reduce costs by identifying geographic areas for more efficient construction scheduling and planning fewer disruptions in traffic flow and to customers. In 2008, the Company was able to implement its various AMRP projects on a less-costly, faster and more efficient neighborhood-wide basis instead of a piece-meal basis of identifying individual lines or responding to individual leaks.

Lastly, the approval of an AMRP cost recovery mechanism will avoid the use of extensive regulatory costs associated with a series of more frequent rate case filings to recover replacement costs. KRS 278.509 recognizes that such programs enhance regulatory efficiency, preserve economies for the Commission and its staff and save customer costs of repeated rate filings.

Q: What are the primary factors causing the revenue deficiency?

A: Since the Commission approved a rate increase for Columbia on August 29, 2007 (for a historical test year ending September 30, 2006), Columbia has invested more than $22 million in capital to serve its customers in Kentucky. Over this same period, Columbia absorbed increased costs for labor and employee benefits, materials, supplies, and other general operating and maintenance expenses. The Company, as more fully explained in the testimony of Columbia witnesses Amy Efland and Mark Balmert, has also experienced a continued decline in the average customer gas usage. As indicated in the testimony of Ms. Efland, since 1999, annual weather normalized usage for residential heating customers has fallen over 18.9% from 89.26 mcf to 72.38 mcf. Early 2009 data indicate a continued usage decline. Similarly, 2009 data are showing a significant decline in usage by the Company's major industrial and commercial customers. These companies include those in automotive manufacturing and supply, steel production, oil refining, glass production and other general manufacturing businesses. In addition, Columbia has also experienced a decline in the number of its customers. In the five years from 2004 through 2008, Columbia's residential customer count dropped from 127,072 to 123,724 a decline of 2.63%. In the historical test year ending December 31, 2008, the decline was 1,229 or almost 1% from the previous calendar year. From 2004 through 2008 the decline in the number of commercial customers was 2.63% and was 0.63% in the test year. Columbia witness Amy Efland provides greater detail of this experience in her testimony. This experience directly impacts Columbia's ability to continue to meet its service obligations to its remaining customers.

Further, since its last rate case, Columbia has experienced an increase in its rate base. The rate base in the 2007 rate case was $171.4 million and it has grown to $ 181.7 million. The key drivers in the increase are the previously mentioned increase to plant offset by accumulated depreciation and deferred taxes.

Q: How was the Company's revenue requirement determined?

A: As described in the testimony of Columbia witness James Racher, Columbia reviewed its costs to serve customers, using a historical test period ending December 31, 2008, pro formed and adjusted for known and measurable changes. Columbia then compared this cost to serve to its test year revenues, adjusted, which produced a revenue deficiency. The revenue requirement is the corresponding amount that Columbia will require to make up this deficiency with a fair return on the investments devoted to serving the public.

Q: Why is the proposed rate adjustment necessary to eliminate the revenue deficiency referenced above?

A: Columbia's current rates do not provide the opportunity to recover its costs to serve its customers, including a reasonable rate of return on the capital invested to provide distribution service to the public. The proposed rates have been developed to cure this deficiency and Columbia witness Paul Moul will support Columbia's proposed rate of return in his testimony.

Q: What parts of a customer's monthly bill will be affected by the proposed rate changes in this filing?

A: The affected portions of a customer's monthly bill are those currently identified as the Customer Charge and the Gas Delivery Charge. These two charges constitute the base rate charges of Columbia's customer bill and typically amount to approximately 20% to 30% of the customer's total gas bill. These two components are charges for having natural gas available to customers, including main installations, line inspections, repair and maintenance, customer service, service personnel, and emergency service and other operational expenses. The largest component of the bill, the Gas Supply Cost, is not affected by this rate request. The Gas Supply Cost is the amount paid for the natural gas commodity itself, its transportation along interstate pipelines and for storage and comprises about 70% to 80% of the customer's total monthly gas bill. It is adjusted pursuant to Columbia's Gas Cost Adjustment Clause to reflect market conditions and historically passed on to customers at cost without any markup. Again, this portion of the gas bill is not affected by the proposed rate request except for the proposed Gas Cost Uncollectible Charge (see the testimony of Columbia witness Mark Balmert).

Q: How will the current Customer Charge and the Gas Delivery Charge be affected?

A: Columbia proposes to change its residential rate design to decrease, and then eliminate, the volumetric rates associated with the Gas Delivery Charge and adjust what is currently called the Customer Charge to be a closer reflection of the actual, non-usage sensitive costs to provide service to customers and allow the Company to earn a fair return. Historically, a portion of Columbia's fixed costs have been recovered through gas delivery charges associated with the volume of usage of the gas commodity consumed by customers, instead of solely being recovered through fixed rates covering fixed costs. While the proposed rate design will reduce the Company's revenues that are dependent on the volume of gas that customers use in the first year of the proposal, it will move to fully align, in the second year of the phased-in plan, the recovery of Columbia's fixed costs through fixed rates. This full decoupling of the commodity charges from the service delivery charges is a type of rate design is often characterized as a straight-fixed variable design. Columbia witness Mark Balmert will explain this proposal in greater detail.

Q: How will this rate proposal impact current residential rates?

A: Under Columbia's proposal, the residential Gas Delivery Charge of $1.8715 per mcf of gas consumed will be shifted, or phased-in, over a period of two years into what will be called the Customer Delivery Charge. The current Gas Delivery Charge will be decreased in two steps and eliminated in the second year of the proposal. The Customer Charge will be adjusted to cover the revenue deficiency and include the shift from the Gas Delivery Charge. For residential customers this will mean a reduction in the Gas Delivery Charge from $1.8715 per mcf to $1.4604 in the first year and to $0.00 in the second year. The fixed monthly charge will concomitantly increase from $9.30 per month to $17.92 in the first year and to $26.53 in the second year. The actual effect on the customer's over-all bill will depend on the volume of gas used (or not used) by a customer. However, under the proposal, based on an annual usage of approximately 71.3 mcf, residential customers will experience a 8.2% increase in current overall rates. I refer you to the testimony of Columbia witness Balmert for the details of this proposal.

Q: What are the benefits to the customers and the utility by this rate design?

A: This type of rate design helps aligns customer interest in conservation and energy efficiency with the utility's concern regarding any resulting decline in usage per customer. Separating fixed costs from volumetric recovery allows a gas distribution company to advocate and promote conservation and efficiency while supporting its fixed costs

Q: Are there other adjustments in fees and charges in the filed tariffs?

A: Yes. Certain services and transactions provided by Columbia which are generally not allocated to all ratepayers continue to increase in cost. While witness Judy Cooper will detail these changes, the following are two examples: (a) the actual cost to reconnect a customer following a disconnection for nonpayment of a bill or a violation of Columbia's rules is $64.20 but the current charge is only $25.00. The proposed change in this tariff is an increase to $60.00. (b) Kentucky regulation 807 KAR 5:006 permits a late payment penalty but does not specify an amount. The Company is proposing to remove the current exemption and apply the 5% late charge for its residential customers as it already exists for commercial and industrial customers. Our understanding that this amount is comparable to those late payment penalties charged by Duke Energy Kentucky, Louisville Gas and Electric Company, Peoples Gas and Atmos Energy Corporation. Both of these changes support the rate-making concept that those causing these types costs to be incurred should the ones who bear the costs rather than being allocated among all ratepayers. Columbia witness Judy Cooper will also describe the other proposed tariff changes, including proposals to allow the Company to waive, under certain conditions, certain costs of remote meter reading devices and to expand the availability and flexibility of the Company's Budget Plan.

Q: What is Columbia's proposal regarding the expense of its pension and other post-employment benefits?

A: Columbia is proposing a base rate recovery and reconciling mechanism for its pension and OPEB expenses. This proposal is described in greater detail in the testimony of Columbia witness June Konold and I refer you to her testimony. Under current accounting rules, pension and OPEB expenses are accrued and charged to operations over the time period employees perform services. The proposal would establish an annual reconciling mechanism to track pension and OPEB expenses different from those included in Columbia's rates and make annual rate adjustments to collect from, or pass back to, customers the amounts of deferred pension and OPEB expenses. This rider is proposed to be called the "Rider POM" (Pension and OPEB Mechanism) and, again, is presented in the testimony of Columbia witness June Konold.

Q: Why is Columbia proposing this change?

A: Columbia has historically maintained the appropriate financial support to fund its pension and OPEB expenses. However, the recent unexpected and extreme fluctuations in interest rates and asset returns, which are not in Columbia's control, have significantly and negatively affected the value of the obligations and related trust assets held for the benefit of our employees. The 2009 pension and OPEB expenses for Columbia employees increased more than $1.366 million from the previous year, an increase of over 1,000%. As described by Columbia witness June Konold, this recent market phenomenon, and the variations from the market in the rate of return experience of the NiSource Master Retirement Trust, have created conditions where is extremely difficult to determine the appropriate level of pension and OPEB expense for inclusion in rates. By the application of a reconciliation mechanism, Columbia customers would only pay an annually adjusted base rate for the change in pension and OPEB expense without the added cost of a base rate proceeding for the recovery request.

Q: Is this request related to Columbia's recently filed request for a deferral of these expenses?

A: Yes, in a recent separate filing Case No. 2009-00168, dated April 23, 2009, Columbia requested the Commission to approve a deferral of the accrued and on-going expenses associated with the Company's pension and OPEB expenses beginning January 1, 2009. Columbia has requested expedited treatment of this request.

Q: Why is Columbia proposing the recovery of uncollectible expense pertaining to the calculated commodity cost of gas through a rider using the Estimated Gas Costs rate in effect at the time of billing?

A: Historically, the uncollectible accounts expense has been recovered through Columbia's base rates. When natural gas costs are relatively stable, this provides a reasonable opportunity for recovery through our base rates. More recent history shows, and in particular during the test year ending December 31, 2008, there has been significant under-recovery of this expense due to the setting of this recovery at the commodity price in effect at the time of the Company's most recent base rate approval. Gas commodity costs are market driven and beyond Columbia's control. In times of high and volatile gas costs, the Company's accounting for its uncollectible expenses is extremely difficult to predict.

Q: How does Columbia propose to address this issue?

A: As described in the testimony of Columbia witness Mark Balmert, the portion of the uncollectible expense that pertains to the calculated commodity cost of gas will be removed from base rates and instead recovered through a surcharge calculated using the commodity Expected Gas Cost rate at the time of billing. The surcharge, proposed to be called the Gas Cost Uncollectible Charge is proposed to be calculated on a quarterly basis and filed along with the current quarterly adjustments to the Company's GCA and recovered through an uncollectible expense rider instead of through base rates. As described by witness Balmert, there would not be a reconciliation of costs and revenues. If the Commission does not approve this rider, Columbia's proposed increase in base rates in this case would have to be adjusted. The mechanism as proposed, however, would better align the timing and amounts of recovery of this expense to the changing gas costs incurred.

Q: Is Columbia proposing any change to address conservation and energy efficiency?

A: Yes, Columbia is proposing a Demand-Side Management program as outlined in the testimony of Columbia witnesses Judy Cooper and Steve Seelye.

Q: Please summarize Columbia's proposed DSM program.

A: Columbia's DSM proposal is being made pursuant to KRS 287.285 and provides for three programs and a cost recovery mechanism. The proposed program is similar to other DSM programs previously approved by the Commission and is described in greater detail in the testimony of Columbia witness Steve Seelye.

Q: What are the primary components of the Program to be offered by Columbia?

A: There are three initial programs for residential customers: (1) An energy audit, made without charge and available to all residential Columbia customers, performed by qualified outside contractors to analyze a dwelling's gas energy efficiency and make recommendations for gas energy savings; (2) A high-efficiency appliance rebate program available to any new or existing residential Columbia customers; and (3) A high efficiency furnace replacement program for low-income customers. The three programs offer a broad-based approach of services to residential customers.

Q: Will Columbia partner with any outside agencies to implement these programs?

A: Yes. Columbia proposes to partner with the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC") to identify and qualify potential participants for the audits and furnaces, as well as work with contractors to install the furnaces. This partnership with CAC can provide opportunities to coordinate this program with the Federal Weatherization Program and other programs including the Kentucky Clean Energy Corps.

Q: Does Columbia propose any Energy Efficiency/Conversation Programs for customers other than its residential customers?

A: This is Columbia's first venture into DSM programs and Columbia believes it is prudent to "test the waters" by gauging customer interest beginning at the residential class. The proposed cost recovery mechanism does provide for recovery of programs to commercial customers and Columbia anticipates that it will seek Commission approval of commercial programs in the future.

Q: How does this DSM program relate to the Company's SFV rate design proposal?

A: As stated more completely in the testimony of Columbia witnesses Mark Balmert and Steve Seelye, these proposals are consistent with one another because the adoption of a SFV rate design will remove the disincentive for Columbia to promote energy conservation and energy efficiency created by volumetric rate recovery of costs. When revenues derived from fixed costs are decoupled from revenues derived from variable costs, the utility becomes financially neutral to the volume of gas sold. This, combined with the incentive provided in the cost recovery mechanism results in the utility, in this case Columbia, becoming aligned with the customer's interests of being energy efficient and reducing energy consumption.

Q: Is Columbia proposing to offer any other new tariff services?

A: Yes. Columbia is proposing a Price Protection Service ("PPS") and a Negotiated Sales Service ("NSS") for customers who want to elect to purchase their gas commodity on a fixed rate basis for a period of time rather than the traditional basis of purchasing gas with quarterly price adjustments that change with the Company's gas supply and other costs.

Q: Why has Columbia developed these service products?

A: The Company has received customer inquires asking why Columbia does not offer a commodity price that can be locked in for a period of time. In response to these inquiries, Columbia is proposing an alternative way for its customers to purchase the gas commodity. The details of this proposal are provided in the testimony of Columbia witness Erich Evans.

Q: Will you please summarize the terms of these proposals?

A: The PPS will be offered to residential, commercial and industrial customers who use 25,000 mcf of gas or less annually. The commodity price will be a stated or indexed amount and fixed for a one year or other stated period. The risk of increases or decreases in the price of the gas commodity will be borne by the Company and will not be trued-up, or reconciled, at the end of the period. The NSS is for customers using over 25,000 Mcf of gas per year and is similar in concept to PPS, except that the services agreement may provide for fixed or variable prices, termination fees, true-up provisions and other terms and conditions.

.Q: Does Columbia propose any changes in the Customer CHOICE program?

A: No.

Q: Does Columbia propose any changes in its energy assistance funding programs?

A: No. Columbia's shareholders, employees and customers will continue to support several forms of energy assistance programs, including WinterCare and Columbia's Energy Assistance Program ("EAP") which are administered by the Community Action Council.

Q: What financial assistance do the Columbia (NiSource) shareholders currently provide for energy assistance to Columbia's low-income customers?

A: Our shareholders contribute approximately $200,000 annually to help low-income customers throughout the Company's service territory pay for their gas heating bills. This amount includes $175,000 annually to the EAP to help pay for gas bills during the heating season (November-March), a dollar-for-dollar matching basis with customer volunteer contributions (up to $20,500 annually) to the Company's WinterCare program (for customers at or below 150% of the federal poverty level) and $5,000 to the Lexington-based Black Church Coalition in 2008.

Q: Do Columbia shareholders financially support other community involvement?

A: Yes, Columbia shareholders contribute approximately $125,000 annually to charitable entities and programs and almost $30,000 annually to economic development activities. These amounts are donated to Kentucky charitable and educational organizations throughout our service territory and are not included in base rates.

Q: Please introduce Columbia's witnesses and generally describe the subject of their testimony.

A: In addition to my testimony, the following witnesses will support Columbia's requests in this case with the following pre-filed testimony:

1. David E. Mueller, who will testify about the Company's infrastructure, its AMRP and other operational issues.

2. Steven Vitale an expert witness of the firm of Black and Veatch Corporation who will provide testimony, from an independent review, regarding the Company's AMRP.

3. Judy M. Cooper who will testify about various tariff modifications and the proposed recovery mechanisms for the AMRP, pension and OPEB expense, and gas cost uncollectible charge.

4. William Steven Seelye, an expert witness of the firm The Prime Group, LLC, who will testify about the design and implementation of Columbia's proposed DSM program and recovery mechanism.

5. James F. Racher, who will testify about the development of Columbia's overall revenue requirement.

6. Paul R. Moul, an expert witness, who will provide testimony concerning the appropriate rate of return for Columbia.

7. Mark P. Balmert, who will testify concerning the Company's billing determinants (including how they are normalized for weather), the rate design and class cost of service study, calculations regarding revenues and proposed rates and the proposed uncollectible expense recovery mechanism.

8. Amy L. Efland, who will testify related to sales volumes, customer trends and weather normalization.

9. Panpilas Fischer, who will present testimony regarding tax issues.

10. John J. Spanos, an expert witness who will provide testimony regarding the depreciation study for Columbia.

11. June M. Konold , who will testify about the requests for accounting treatment and proposed recovery mechanisms for the Company's pension and OPEB expense.

12. Erich A. Evans., who will provide testimony about the PPS and NSS proposals.

Q: Does this conclude your Prepared Direct Testimony?

A: Yes, however I reserve the right to provide rebuttal testimony.

Columbia Exhibit No. ___.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
DAVID E. MUELLER
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF DAVID E. MUELLER

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is David E. Mueller and my business address is 2001 Mercer Rd., Lexington, KY.

Q: What is your current position and what are your responsibilities?

A: I am the Manager – Operating Center for Columbia Gas of Kentucky ("Columbia"). I manage Columbia's natural gas distribution operations within its Kentucky service territory. I am accountable for the leadership and direction of distribution field operations in all of Columbia's service territories. My responsibilities include oversight of Gas Distribution plant and service activities. I collaborate with other key business partners for System Operations, Meter Reading, Engineering, Planning, Scheduling, Assigning Construction and Customer Service.

Q: What is your educational background?

A: I attended Purdue University in West Lafayette and Hammond, Indiana, graduating with a BS in Engineering in 1985. I graduated from Indiana University at South Bend with a Masters in Business Administration in 1993.

Q: Please describe your employment history?

A: I joined Northern Indiana Public Service Co., a NiSource affiliate gas and electric distribution company located in northern Indiana in 1978 as an Engineering Technician responsible for design of gas and electric distribution systems. From 1981 to 1990 I served in various leadership roles as a commercial and industrial gas applications engineer. From 1990 to 1994 I was engineering supervisor responsible for gas system planning, maintenance, compliance and large project management. In 1994 I joined Northern Indiana Fuel and Light Co., a subsidiary gas company to NiSource, as Operations Manager, responsible for all aspects of distribution and transmission operations. From 2007 to present I have been Manager – Kentucky Operating Center 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, its historic operating performance; and its Accelerated Main Replacement Program ("AMRP"). In addition to my testimony, Columbia has retained Steven Vitale of Black & Veatch to render an independent opinion as to the need and appropriateness of Columbia's AMRP. Mr. Vitale will be submitting both a comprehensive report on his review, as well as, written testimony to support Columbia's 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 historic operating performance. Section V discusses the AMRP.

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

Q. What geographic area does Columbia serve?

A. Columbia's service territory is spread across the east central, north central and eastern parts of Kentucky. Columbia services customers in and around the cities of Frankfort, Versailles, Midway, Lexington, Georgetown, Cynthiana, Paris, Winchester, Mt. Sterling, Irvine, and Richmond. Columbia also services customers in Maysville, Ashland and several communities along the Ohio River from South Shore to Louisa. In eastern Kentucky Columbia serves several smaller towns and communities such as Beauty, Lovely, South Williamson, Betsey Layne, Inez, Warfield, Pippa Passes, Lancer, Drift, Hindman and Harold.

Q. Please describe Columbia's gas distribution system.

A. Columbia Gas of Kentucky was incorporated in 1958 from consolidations of many companies over a period of time. The companies include Central Kentucky Natural Gas, Lexington Gas Company, Huntington Gas Company, Frankfort Kentucky Natural Gas Company, United Fuel Gas Company, Inland Gas Company, and Limestone Gas. As a result of these consolidations, Columbia's distribution system consists of many independent systems and various types of pipe. Collectively, these systems deliver end-use natural gas service to approximately 140,000 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 natural gas producing regions of the southern United States and eastern Kentucky. Columbia distributes natural gas by taking it from delivery points ("city gates") along interstate and intrastate pipelines, then transporting it through approximately 2,500 miles of relatively small-diameter distribution main that network underground between and through cities, towns and neighborhoods. The natural gas is then delivered by way of approximately 140,000 customer service lines to meet the demands of Columbia's residential, commercial and industrial end-use customers.

Columbia Gas receives the natural gas commodity at the city gate where the transmission pressure of the gas is reduced to local distribution pressure. An odorant known as mercaptan is typically added to the natural gas at the city gate also, before it is delivered into the distribution system. The gas then flows through 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. HISTORICAL 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 the purposes of operating and maintaining its gas systems and responding to emergencies.

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

A. Yes. Columbia has written its O&M plans to conform with state and federal requirements specified in 807 KAR 5:022 and 49 CFR Part 190-192 respectively.

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 Kentucky Public Service Commission 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 of five (5) years not exceeding sixty-three (63) months unless the pipes involved are unprotected steel, in which case a leakage survey is performed at intervals of three (3) years not to exceed thirty-nine (39) months.

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 not later than fifteen (15) working 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 with-in 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. These gas leak classifications are based on the guidance provided in the Gas Piping Technology Committee ("GPTC") ANSI Z380.1 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and state pipeline regulators as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards."

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. Approximately 94% of our priorities are responded to in less than one hour. Columbia has maintained its commitment to a safe and reliable system for its customers. Furthermore, Columbia monitors all of its systems for leakage, grades all found leaks and repairs its leaks in compliance with its written O&M plans and state and federal regulations.

V. ACCELERATED MAIN REPLACEMENT PROGRAM

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

A. A significant percentage of Columbia's gas distribution mains and services are reaching the end of their useful life. In 2008, Columbia began its Accelerated Main Replacement Program ("AMRP") to more aggressively replace these mains and services than in the past. In order to provide safe, reliable delivery of gas service, Columbia has begun the replacement of certain types of gas main and services through continuous evaluation, planning and prioritization based on the serviceability of these systems. The types of main identified for replacement in Columbia's AMRP are unprotected bare steel, cathodically protected bare steel, cathodically un-protected coated steel, ineffectively coated steel and cast iron. Columbia considers these types of gas distribution main, "Priority Pipe" or "Priority Main". As part of its AMRP, Columbia also intends to replace all metallic service lines, and service lines which do not meet current material and construction standards. Columbia plans to replace these mains, service lines, and associated appurtenances over a span of approximately thirty (30) years, beginning in 2008, and estimates the total program will cost approximately $210 million. Annual replacement cost may vary from year-to-year, based on system condition and performance. Annual capital investment is estimated at approximately $7 million.

Q. Why does Columbia need an AMRP?

A. Columbia's distribution system consists of approximately 525 miles of protected and unprotected bare and ineffectively coated steel and cast iron mains and the associated services, meters and facilities necessary to render natural gas delivery service. Many of these facilities are continuously subjected to corrosion and ground movement. Over half of this pipe was installed before 1950, while the remainder was installed between 1950 and 1969. Columbia's priority mains and associated services are at a point in their useful life where some areas have begun corroding in an accelerated manner. Continuation of Columbia's AMRP in 2009 will reasonably allow Columbia to replace its highest risk pipe, thus reducing the accelerating leakage rates. This program will significantly improve safety and reliability of service for our customers. Notwithstanding public safety, a well planned systematic approach to infrastructure replacement will reduce inconvenience to the public, requiring fewer unplanned disruptions to traffic for emergency repair, and improve coordination with local city and town governments.

Q. You mention unprotected steel, 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 1800s to the 1950s, Columbia, its predecessor companies and the rest of the gas industry primarily installed pipe made of cast iron and unprotected bare steel. Columbia continued to install unprotected bare steel in the 1950'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 in use today. Attachment DEM-1 shows a breakdown of Columbia's gas distribution system by material type in miles of pipe.

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 materials available, and was the pipe of choice in the late 1800s and early 1900s. Cast iron was relatively strong and was easy to install. However, it is susceptible to cracking when excessive stress and pressure is applied to the pipe, thereby making it vulnerable to breakage from ground movement and other forms of environmental loading. Furthermore, cast iron pipe utilizes a bell and spigot joint method to join each section of pipe. Over time this joint method is prone to leakage. Finally, it was determined that cast iron pipe was unsuitable for the higher pressures needed to transport large volumes of gas over long distances.

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

A. By the 1920s, the industry had adopted bare steel piping for mains. Bare steel was deemed to be stronger than cast iron and able to withstand greater gas pressure. During this time, bare steel began replacing cast iron pipe as the material of choice for building a natural gas distribution system. During the post-World War II construction boom, Columbia installed a significant amount of bare steel mains and services. The use of bare steel was common until the 1950s and 1960s when the industry began to realize that despite its strength, bare steel was subject to on-going deterioration of pipe wall from galvanic corrosion.

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

A. Yes, due to its lack of an external electrical insulation coating, bare steel is subject to galvanic corrosion. Specifically, galvanic corrosion when left unaddressed, reduces the wall thickness of steel pipe that increases the risk of leakage or fracture. Cast iron mains are susceptible to leakage due to joint separation and failure, and pipe wall cracking due surface conditions such as; traffic, soil subsidence, movement in the soil from freezing or drought conditions, and construction activity. Furthermore, cast iron is susceptible to graphitization, a process that causes the pipe wall to soften with age, making it more susceptible to failure. Unprotected bare steel and cast iron are subject to leaks at a greater rate than cathodically protected coated steel or plastic mains. Pipe of this type, which is more prone to leak, can lead to safety and reliability risks, greater line losses, and higher operating and maintenance expenses.

Q. Explain the process of galvanic corrosion.

A. Galvanic corrosion is a natural electro-chemical reaction that is responsible for the majority of corrosion that leads to loss of pipe wall thickness, 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 galvanic potentials);

2. An electrical path between the metal surfaces with dissimilar galvanic 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 between metals that is the driving force for galvanic corrosion. The less noble metal (that having a more negative electrical potential relative to another) in a corrosion cell will become the anode and tend to undergo accelerated corrosion for a given electrolyte, while the more noble metal (that having a less negative electrical potential relative to another) will become the cathode in a corrosion cell and will not experience corrosion effects.

In its native form, without application of protective materials and systems, all of the conditions exist for galvanic corrosion when bare steel is buried in soil. Dissimilar metals having electrical potential differences and a current path can exist between the surfaces of individual joints of steel, submerged in an electrolyte such as soil or water, and can even exist on the same section of pipe due to a variety of factors such as handling, manufacturing inconsistencies, installation practices 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. Finally, all underground pipelines are surrounded by soil which functions as the electrolyte in a corrosion cell. Because all the requirements exist in buried pipelines, galvanic corrosion for bare steel and ineffectively protected steel pipe starts as soon as the newly constructed pipeline is backfilled. Unchecked the corrosion process continues without interruption until anodic areas of the pipeline are consumed. 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 their first installation in the early 1900s. Some of these pipelines have been in operation for up to 100 years.

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

A. Natural gas distribution companies began applying an exterior dielectric (insulating) coating to steel pipe. The coating was intended to electrically isolate the steel from the surrounding soil (electrolyte). By eliminating one of the requirements for corrosion, the expectation was the elimination of galvanic corrosion in buried steel pipes.

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

A. No, despite the best efforts of industry to produce the perfectly designed and applied dielectric coating did not solve the corrosion problem. Coated steel corrodes anywhere there is a flaw in the coating, often caused during manufacturing, handling and installation, allowing the soil to come in contact with a bare steel surface on the pipeline. At these locations, galvanic corrosion often occurs in vary pronounced ways. However, for the period from the 1950s through the 1960s, 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 did industry do to reduce galvanic corrosion of buried coated steel pipe?

A. Industry applied cathodic protection techniques in conjunction with the insulating coating.

Q. What is "cathodic protection" and how does it supplement the benefits of the insulating coating to minimize corrosion to coated steel pipes?

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 bare surfaces of the pipe in such a way as to alter the electrochemical process and eliminate the metal loss at the point where the bare steel contacts the soil. Essentially, cathodic protection reduces corrosion by making an uncoated surface of the pipe, that is exposed to the soil, the cathode, by attaching an anode, such as another type of metal that is galvanically more negative in potential to the pipe. While the primary function of a pipeline coating is to electrically isolate the pipe surface from the soil, thus minimizing galvanic corrosion, no coating is perfect. So in effect, the coating only minimizes the bare steel surface area that is in contact with the soil. By applying as little as 1 milli-amp of current per square foot of bare steel surface area, from sacrificial anodes or other impressed current devices, cathodic protection current minimizes galvanic corrosion to exposed bare steel caused by coating defects. While it is possible to protect entire bare steel systems with cathodic protection systems, the amount of electrical current required along with many other operational problems makes cathodically protecting bare steel systems physically and economically impractical. Minimizing the bare steel surface area of a pipeline in contact with the soil through the use of coatings in conjunction with small amounts of current is the most effective, manageable and economical way to protect steel pipelines from galvanic corrosion.

Q. You mentioned using unprotected coated pipe as a means to improve the corrosion performance of buried metallic pipe over that of bare steel. Has Columbia taken steps to reduce galvanic corrosion on previously installed unprotected coated steel pipe?

A. Yes. Columbia has tested and evaluated all of the unprotected coated steel mains and associated services on a system-wide basis, installed in its system prior to July 31, 1971, pursuant to state and federal pipeline safety regulations. Pipeline sections determined to have effective coating through testing and inspection were electrically isolated and cathodically protected in accordance with Appendix D of 49 CFR Part 192. These pipelines perform much like the newly installed protected coated steel pipe of today. Those main and service pipelines deemed to have ineffective coatings or were unable to be electrically isolated in a practical way, such that they have the same basic corrosion issues as bare steel, were designated as ineffectively coated steel pipe and treated as cathodically unprotected pipe pursuant to state and federal pipeline safety regulations. Cathodically unprotected pipe, considered as priority pipe, is monitored, and repaired or replaced in accordance with 49 CFR Part 192 and Title 807 KAR 5:022 regulations. Ineffectively coated steel pipe is included in Columbia's AMRP.

Q. Are there any other pipe materials included in AMRP other than cast iron, bare steel and ineffectively coated steel?

A. Yes. In 1989, Columbia assumed responsibility for the customer's service line that typically extended from the customer's property line to the meter. In some cases we have found that customer service lines installed prior to 1989 by private plumbers and contractors do not meet our current construction and installation safety standards to function in our new distribution systems. Even though these lines may be plastic, coated steel or other materials, approved at the time of installation, in many cases they are not installed to proper depths, materials used do not meet current day standards, and pipe joints and other fittings are often not rated for the elevated pressures used in modern day distribution systems.

In specific cases, short pieces of plastic pipe were installed to replace priority pipe that had deteriorated beyond the point of repair. In most of these cases replacing this pipe as a part of the AMRP is more cost effective and less inconvenient to customers than trying to incorporate it into our new systems.

Q. How are service lines being treated under the AMRP?

A. We are replacing all service lines regardless of material, that do not meet current material and construction standards, where compliance with current material and construction standards are not practical to determine, and where failing to do so will create additional legacy operating and maintenance costs. Generally, services are replaced at the same time we replace the main piping or in those cases where individual service lines are replaced on a random basis due to emergency leakage, damage, or other relocation or replacement requirements. In most cases service lines are replaced with the same plastic material as used for mains. All of these costs are included in the AMRP.

Q. Has the industry further improved the functionality of its piping since the introduction of cathodically protected 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 are much improved. Cathodically-protected coated steel has many mechanical advantages due to its strength; it is also highly corrosion resistant due to the impressed electrical current from cathodic protection systems. 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 is strong, flexible, and chemically resistant to damage. As a result, plastic pipe is generally immune to the stress of ground movement, chemical contamination and corrosion. Plastic pipe is also less costly to purchase and easier to join and install than steel pipe.

Q. Does plastic pipe have any drawbacks?

A. The single significant drawback to plastic is its relative vulnerability to excavation 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 using mechanized machinery and other high impact equipment in the vicinity of plastic facilities are more likely to damage plastic pipe than metallic pipe.

Q. Please describe the manner in which Columbia has addressed replacement of its priority pipe.

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

Q. Why does Columbia believe it should continue its AMRP?

A. As stated earlier, Columbia has approximately 525 miles of Priority Pipe remaining in its system along with its associated service lines, and other appurtenances. This pipe has been exposed to the effects of galvanic corrosion since its installation, of which most of the unprotected steel and cast iron pipe is between 50 and 100 years old.

In 2007 Columbia repaired 1,120 corrosion leaks on these systems. Over the past 10 years corrosion has accounted for 73% of leaks on mains and 72% of leaks on services, excluding third party damage. These leaks occurred on approximately 19% of Columbia's total inventory of mains and 10% of Columbia's total inventory of services. While leakage rates have trended down somewhat from over the past 10 years, leakage rates in 2006 and 2007 have begun trending upward compared to the two previous years, in spite of Columbia's solid operational practices. Furthermore, over the past four years, Columbia has seen a rise in the number of emergency replacements of short sections of pipe. As stated earlier, leakage rates increase with age on unprotected steel pipe and cast iron. At the current 10-year average rate of replacement it will take an additional 52 years to replace all of the priority mains and services. While Columbia will continue to replace its highest priority pipe, at this rate Columbia's latest vintage pipe will be 91 years old by the time it is replaced. Because of these factors and others stated earlier, Columbia believes it is in the best interest of its customers and public stakeholders to continue its AMRP to replace the remaining priority pipe in a planned, efficient, and cost effective manner.

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

A. Columbia trains and qualifies 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 excluding third party damage, approximately 73 percent of all main leaks are the result of corrosion on unprotected bare steel mains and 72 percent of leaks are the result of corrosion on unprotected bare steel services. The third party 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. The combined effects of aging pipe and continuous corrosion increases the potential of an incident occurring.

Q. Are you saying Columbia's system is unsafe?

A. No, the system is safe right now, as evidenced by Columbia's ability to address all Grades "1", Grade "2 Priority" and Grade "2" leaks in accordance with its operation and maintenance plan. The system is comprised of approximately 525 of miles of priority pipe with another 2,000 plus miles of cathodically-protected coated steel, and plastic pipe. The material initially at risk is first generation unprotected steel and cast iron. This material will continue to deteriorate and will gradually have more leaks with increasing severity. While the system is currently safe, Columbia must, as a prudent, safety-conscious operator, address the systemic problem of replacing its unprotected steel and cast iron facilities before the problem significantly impacts safety and reliability. This is why Columbia implemented the AMRP.

Q. Is replacement the only remedy? Is there any other way to retard or arrest the corrosion problem inherent in unprotected 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. However, in practice, 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 undo or replace the damage that has already occurred on a bare steel system.

Q. Where is the most pronounced corrosion problem?

A. Corrosion leakage exists in all of Columbia's system, but presently it is particularly severe in the Lexington and Frankfort systems, which have the most unprotected steel pipe than any other part of the Columbia's service territory.

Q. Do system operation requirements demand replacement of unprotected steel in Lexington, Frankfort and elsewhere?

A. Yes. Continual system degradation due to unrelenting galvanic corrosion will eventually strain Columbia's resources to ensure delivery of safe and reliable service. We believe that it is now prudent to continue with a more aggressive accelerated main replacement program to maintain the safe, reliable service that our customers expect.

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 began ramping up its capital replacement program in 2007. Specific replacement projects were identified, planned, designed and constructed that were of similar size and scope as those anticipated in an AMRP. The outcome of the preliminary program gave us the opportunity to retire deteriorating high priority pipe. Additionally, Columbia began to assess the complexity of managing a larger AMRP and evaluate internal and external resource needs, construction practices, computer applications and analysis tools, communication strategies, opportunities to leverage economies of scale for materials, and developing program plans and goals.

Q. How did Columbia budget its capital program for the AMRP in 2008?

A. Specific replacement projects were identified and prioritized based on discussions with and experience of operating and engineering personnel of the leakage rate and construction factors influencing public safety and reliability. A budget of approximately $9.4 million was developed to replace 116,000 feet of deteriorating main piping, replace approximately 1148 service lines, upgrade associated facilities and appurtenances with materials and fabrications designed and constructed to operate with higher pressure systems, acquire right-of-ways and the necessary permitting, and restore surface structures disturbed during installation.. The replacement budget included finances for both planned projects and those main, and service facilities requiring replacement on an emergency basis.

Q. What was the outcome of Columbia's 2008 AMRP?

A. In 2008 Columbia planned, designed, and constructed 104,000 feet of replacement mainline piping, 1,933 deteriorating services, and moved outside the associated customer meters. Subsequently, Columbia was able to retire approximately 105,000 feet of high priority deteriorating mainline piping, and 1,933 high priority deteriorating service lines.

Q. What is the expected budget for the AMRP in future years?

A. Columbia estimates it will spend approximately $210 million on its AMRP over 30 years beginning in 2008. In 2009 Columbia has budgeted approximately $7 million for its capital replacement program. Future projects and annual budgets will vary somewhat as we replace the highest priority pipe based on system condition and performance. While public safety and potential risk are always the primary considerations of project selection, the timing and extent of replacement cost recovery can impact the scope of replacement projects in any given year. Fair and timely investment recovery via the "AMRP Rider," explained in Columbia witness Cooper's testimony, provides a critical and predictable base of capital to finance our AMRP over approximately the next thirty (30) years. The 2009 capital replacement program is the second full year of Columbia's AMRP.

Q. Did Columbia evaluate its internal resources necessary to implement the AMRP?

A. Yes. In 2006, 2007, and 2008, several of Columbia's departments including Operations, Construction, and Engineering evaluated their staffing needs and added to complement where necessary and as appropriate. Most of the staffing additions were strategically located in areas to support the AMRP. Columbia will continually review its 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 rather than a segmented replacement approach which targets discrete areas, neighborhood-by-neighborhood, and block-by-block, in a geographically continuous fashion. This is an efficient installation practice because construction crews can stage work by continuously 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. Incorporating this type of design and construction approach should result in a per foot installation cost less than that which would be achieved by bidding smaller and more discrete project. 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. Under the AMRP we will target those portions of our system primarily comprised of priority pipe for replacement based on the needs driven by the distribution system, and in accordance with the basic tenets of system engineering and planning. 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, the need for relocation due to public infrastructure projects, and expected growth in system demand requirements. By planning and constructing our replacement projects on a system wide or regional basis we will maximize efficiencies and minimize costs in a number of ways. Large scale projects will allow us to leverage, material purchases, obtain the best construction and restoration contractor costs, and acquire land and right-of-way, when needed, more cost effectively. Moreover, planning, designing and constructing regional and system wide facilities will reduce the amount of redundant mains, services and associated facilities necessary to support gas service delivery and allow us to optimize the size of and amount of new facilities against the amount of priority pipe that we can retire. Finally, as a part of the AMRP, we will construct new facilities using standard materials and construction practices in the most cost effective manner, even to the extent that projects may require replacement of main and service piping constructed of material other than that identified as priority pipe. This approach will allow us to utilize best construction practices as they are implemented over a widespread part of our impacted distribution system to reduce construction costs and allow us to adopt and employ best operating and maintenance practices to reduce future O&M legacy costs.

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 and coated steel throughout the system.

Q. What do you mean by sizing the pipe to engineering and operations system design requirements?

A. Gas distribution systems are typically planned and designed on a twenty-year horizon. Planning dictates that Columbia look ahead for engineering and operational purposes as far as possible. The choice and size of replacement pipe will take into account the engineering and other requirements of system design.

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

A. Yes. Columbia has purchased a site license for Optimain DS™ to assist in the evaluation and ranking of pipeline segments against a range of environmental conditions, risks, and economic factors.[1] The Optimain tool provides a consistent, objective framework for collecting, viewing, and analyzing pipeline data such as pipe attributes, leakage history, pipe condition, and environmental factors. The software utilizes business rules to characterize the pipe into a risk profile where the pipeline segments can be ranked and combined into an AMRP project. The Optimain tool will greatly enhance our ability to identify and plan replacement of our highest priority pipe in a manner that is consistent with our AMRP replacement strategy. Additionally, Optimain has built-in functionality that will eventu-

---

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

ally communicate with Columbia's Geographic Information System currently under development.

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 AMRP. As stated earlier, more than seventy percent of our leaks are due to corrosion on unprotected steel mains and services. 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 and inconvenience due to emergency repair, will be the largest benefit for our customers.

Q. In planning the AMRP, were alternatively defined lengths of the program considered, and why was a thirty year period selected?

A. Various program lengths were evaluated, but the duration of thirty years was chosen because it matched the best combination of risk (the safe and reliable delivery of natural gas), and resources needs (internal/external labor, material, capital, etc.). Although Columbia believes the unprotected steel, and cast iron mains, services, meters, pressure regulating equipment and associated equipment necessary for safe efficient gas distribution operations should be replaced as expediently as possible, internal and external resource constraints have driven us to choose thirty 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 performance of its operating system and the effectiveness of the replacement program and make adjustments as necessary to ensure safe and reliable delivery of service.

Q. What assumptions are behind the cost estimate of $210 million?

A. As I mentioned earlier, this dollar estimate captures all of the planning, design, construction and retirement of approximately 525 miles of unprotected bare steel, ineffectively coated steel, and cast iron mains, facilities associated with supporting the gas distribution systems over the duration of the AMRP, the replacement of all associated service lines, meter installations and related appurtenances.. The total cost estimate is based on current dollar value and includes cost efficiencies 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. Public safety is enhanced because the AMRP will greatly reduce the increasing risk associated with aging facilities exposed to continuous corrosion forces.

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. In some cases it may be possible to coordinate projects around other municipal planned infrastructure improvements such as road replacement, repaving, and sewer and water replacement thus providing overall benefits of public convenience and cost savings to local neighborhoods and communities. Greater cost savings will be achieved through an engineering and operations pipe sizing approach.

Q. What are the economic benefits of the AMRP?

A. 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 cost. 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. Columbia's 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?

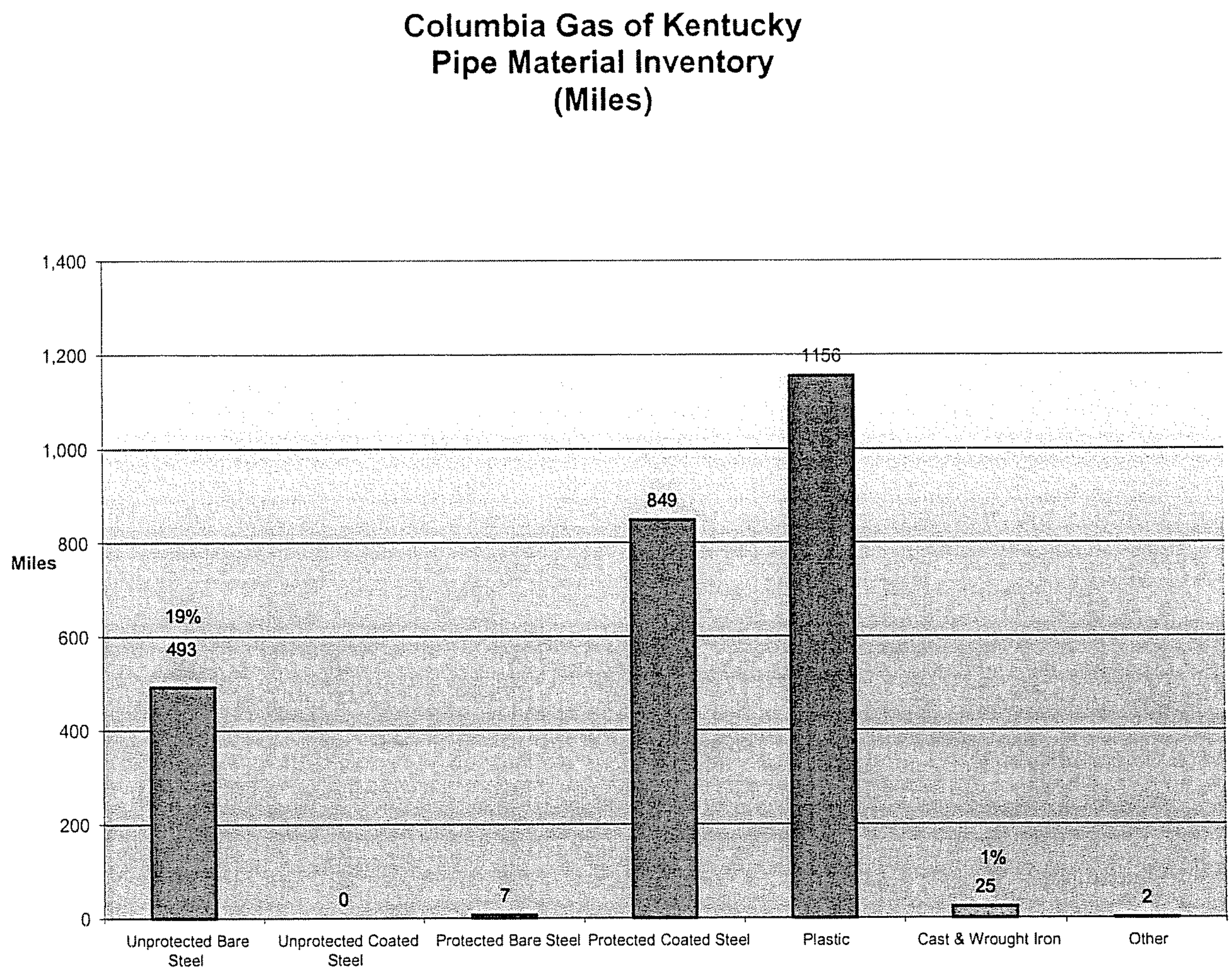
A. Columbia will replace deteriorating main and service pipe and enhance the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Its system will continue to be able to provide deliverability at its Maximum Allowable Operating Pressure to ensure reliable service delivery and increase the system capacity to support economic development efforts. Finally, as main or service lines are replaced Columbia will move, 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. This will reduce customer inconvenience and improve meter reading and billing accuracy.

VI. CONCLUSION

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, it does; however, I reserve the right to file rebuttal testimony if necessary.

Attachment DEM-1



Columbia Gas of Kentucky Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

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

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

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 a 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 became KeySpan Energy and today is a part of National Grid. 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 am testifying in support of Columbia Gas of Kentucky, Inc.'s ("Columbia") Accelerated Mains Replacement Program ("AMRP"). In that regard, I also support Black & Veatch's 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 Non-Cathodically Protected Bare Steel Distribution Piping of Columbia Gas of Kentucky, 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 and opinion of Columbia's need for its accelerated bare steel and cast iron mains and bare steel services 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, Pipeline and Hazardous Materials Safety Administration (PHMSA), 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 1998 through 2007. Distribution operator data for 2008 will not be available until later in 2009. We observed that in 2007 there were 1,426 companies filing reports of which about 1,208 had no miles of non-cathodically protected or unprotected bare steel main. 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 unprotected bare steel in their distribution system. Recognizing that Columbia reported approximately 500 miles of unprotected bare steel, Black & Veatch recommended a sorting criterion of a minimum 50 miles of unprotected bare steel. We believe those companies with at least this amount of unprotected bare steel are facing similar issues regarding maintaining and replacing these pipes. Across the nation there were 85 gas system operators reporting having 50 miles or more of unprotected bare steel in their distribution systems. These 85 companies have 97% of all of the unprotected bare steel gas distribution system mains in the nation. Within the same geographic region as Columbia there were 19 companies reporting having 50 miles or more of unprotected bare steel in their distribution systems. By using the term region, I refer to distribution operating companies in Kentucky and the states that border Kentucky. 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 during the period 1998 through 2007 that gas leaks due to corrosion accounted for 73% of all of Columbia's gas leaks on mains, on a weighted average basis, excluding leaks caused by excavation or third party damage. For gas services, gas leaks due to corrosion accounted for 72% of all of Columbia's leaks on gas services, on a weighted average basis, excluding leaks caused by excavation or third party damage. These gas leaks due to corrosion predominately occur on Columbia's unprotected bare and unprotected coated steel mains and these mains make up only 19% of Columbia's inventory of gas distribution mains and 10% of Columbia's inventory of gas services.

In 2007 Columbia reported having 493 miles of unprotected bare steel main remaining it its system, which ranks Columbia as having the 24th largest number of miles of unprotected bare steel main among all gas distribution companies reporting to the DOT. Columbia also reported that it had repaired or eliminated 246 gas leaks that were caused by corrosion which ranks Columbia as having the 37th highest number of gas leaks due to corrosion eliminated or repaired on mains of 85 companies in the DOT database with 50 miles or more of unprotected bare steel in their systems.

We calculated the corrosion leak rate on mains for Columbia in 2007 to be 0.50 gas leaks due to corrosion per mile of unprotected bare steel and unprotected coated steel main. While this metric for 2007 is better than the weighted average for national and regional companies, which for both is approximately 0.72, as the Columbia's unprotected bare steel pipe inventory continues to age, we believe the annual number of gas leaks due to corrosion on these mains will increase.

Regarding gas services, as of the end of 2007 Columbia reported that there were 14,137 unprotected bare steel gas services remaining in its system. We calculated the corrosion leak rate on gas services for Columbia to be 61.8 gas leaks due to corrosion per 1,000 unprotected bare steel and unprotected coated steel services. This metric for 2007 is higher than the weighted average of 12.5 for national companies and 10.4 for regional companies. This is an additional reason why we support the inclusion of the replacement of unprotected bare steel services in Columbia's accelerated mains replacement program.

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

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 gas leak due to corrosion occurs. However, once the first gas 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 gas 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 gas leak rate as the pipe becomes fragile and sometimes unrepairable. In other words, once a section of pipe starts to develop gas leaks due to corrosion, experience has shown that the pipe will develop more and more gas leaks at a continuously increasing rate over time.

The second reason this is important to the public and Columbia is if for example the corrosion leak rate on mains was to rise to the levels of the weighted average of the regional companies, Columbia would experience a 45% increase in the annual number of gas leaks due to corrosion. Based on our discussions with the Company and our experience, we believe this scenario would create additional safety and reliability risks for the public and Columbia's employees, as well as, create a gas leak management challenge for the Company.

Q. What are Columbia's higher risk mains and services?

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 higher risk materials include, non-cathodically protected bare and non-cathodically protected 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 higher risk 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. Furthermore, all of Columbia's cast iron mains are less than or equal to 8" in diameter and 20 miles of its total of 25 miles of cast iron are less than or equal to 4" in diameter. These smaller diameter cast iron mains are considered higher risk mains.

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. Over the ten year period 1998 through 2007, Columbia's average annual rate of replacement of unprotected bare steel and unprotected coated steel main was approximately 9.4 miles. Extrapolating this rate of replacement into the future would result in the replacement of its bare steel main inventory in approximately 52 years. At this rate, Columbia's newest vintage higher risk mains installed in the 1960's would be at least 91 years old once they are finally replaced. Black & Veatch believes that these higher risk mains will continue to leak due to corrosion, 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.

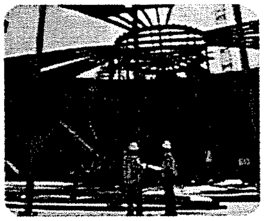
It is our opinion that it is in the best interest of Columbia's customers that it identify and prioritize its high risk mains and services for replacement, and accelerate the replacement of these mains and services before the leak rates gets out of hand. Columbia's plan to increase the replacement rate of its higher risk pipe, and replace these pipes within 30 years, in our opinion, will have the desired result of reducing gas leaks due to corrosion. We believe that an accelerated mains and services replacement program will improve both the safety and reliability of its gas distribution system by eventually eliminating the source of 73% of Columbia's gas leaks on mains and 72% of the gas leaks on services. Without such an accelerated replacement effort, it is our opinion that Columbia and the public may face the risks associated with an ever increasing number of corrosion leaks on these mains and services.

Furthermore, in addition to the customer safety and system reliability benefits mentioned throughout Black & Veatch's report, a well planned accelerated mains and services replacement program would have a host of qualitative benefits for the public. For example, these benefits include 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 gas system reliability benefits, it is our opinion that prudent utility system operators need to manage in a mode that protects the customer, assures the integrity of the gas system, and does not cause unnecessary inconveniences for customers.

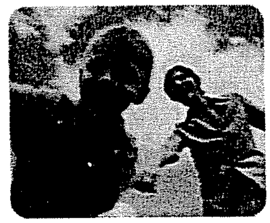
Q: Does this complete your Prepared Direct Testimony?

A: Yes, it does; however I reserve the right to file rebuttal testimony if necessary.

BUILDING A WORLD OF DIFFERENCE®







Comparative Analysis of the Non-Cathodically Protected Bare Steel Distribution Piping of Columbia Gas of Kentucky, Inc.

ATTACHMENT SV-1

December 22, 2008

BLACK & VEATCH
Building a world of difference®

TABLE OF CONTENTS

SECTION

APPENDICES

EXECUTIVE SUMMARY

Purpose

At the request of Columbia Gas of Kentucky, Inc. ("Columbia" or the "Company"), Black & Veatch Corporation ("Black & Veatch") has performed a comparative analysis of Columbia's non-cathodically protected (unprotected) bare and unprotected 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 1998 through 2007.

The purpose of this analysis was to provide Columbia with: 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) unprotected bare and coated steel mains, b) cast iron mains; and c) unprotected bare and coated steel services. Natural gas mains and services made of these materials are understood by the natural gas industry to be higher risk pipes compared to cathodically protected coated steel and plastic mains and services.

Findings – Natural Gas Mains and Corrosion Leaks

As of October 20, 2008, while 1,426 companies have filed with the DOT, only 85 companies reported having 50 miles or more of unprotected bare steel gas mains remaining in service in their distribution systems.

DOT data indicates that Columbia had 493 miles of unprotected bare steel gas mains and 14,137 unprotected bare steel services remaining in service on its distribution system in 2007. On the basis of total number of miles of unprotected bare steel mains, Columbia ranked 24th highest out of 85 companies. Columbia also reports not having 1) any unprotected coated steel mains or services remaining in service in its distribution system or 2) any unprotected bare or coated steel remaining in service in its transmission system.

In 2007 Columbia reported having repaired or eliminated 246 gas leaks due to corrosion on mains and 874 gas leaks due to corrosion on services. For the ten year period of 1998 through 2007, gas leaks on mains due to corrosion accounted for on average, 73% of Columbia's total number of gas leaks on mains (excluding leaks due to third party damage/excavation). These gas leaks due to corrosion predominately occurred on only 19% of Columbia's total inventory of mains. For the same 10 year period, leaks on services due to corrosion accounted for on average 72% of Columbia's total number of gas leaks on services (excluding leaks due to third party damage/excavation). These gas leaks due to corrosion predominately occurred on only 10% of Columbia's total inventory of services. These pipes are Columbia's remaining non-cathodically protected bare steel mains and services.

The focus on the number of gas leaks due to corrosion and corrosion leak rates 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.

Based on the leak management measure of the annual number of gas leaks due to corrosion on mains per mile of non-cathodically protected bare and coated steel mains, in 2007 Columbia had maintained a lower value at 0.50 corrosion leaks per mile of non-cathodically protected bare and coated steel mains compared to the

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

weighted average value of 0.717 for regional companies (not including Columbia) and 0.725 for national companies (not including Columbia) that reported having 50 miles or more of unprotected bare steel main in their distribution systems.

From the data we also observed the Company's level of gas leaks awaiting repair at the end of 2007 (also know as year-end backlog or open leaks) increased by 171 leaks (122%), while at the same time the total number of corrosion leaks on mains and services that were repaired increased by 61 leaks (6%). If the year-end backlog had decreased, that may have been a reason why corrosion leaks may have increased. However, the 2007 increase in both the number of corrosion leaks repaired on mains and services, as well as an increase in the number of leaks in the year-end backlog, is an indication that the increase in corrosion leaks was not due to the Company applying extra efforts to reduce its leak backlog (which would include some leaks caused by corrosion). This suggests that Columbia did experience an increase in leaks due to corrosion in 2007.

For the ten year period 1998 through 2007, Columbia maintained a rate of gas leaks due to corrosion on mains that was lower than the weighted 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 unprotected bare steel pipe inventory continues to age we believe Columbia's leak rate will increase. If the 2007 corrosion leak rate on mains for Columbia (0.50) was to simply rise to the level of the weighted average corrosion leak rate on mains for regional companies (not including Columbia) in 2007 (0.72), that would mean that Columbia's annual number of gas leaks due to corrosion would increase from 246 to 357 leaks (a 45% increase).

We believe that such higher levels of gas leaks due to corrosion could create additional safety and reliability 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 towards accelerating the identification and replacement of its higher risk mains, before the leak rate becomes excessive, is a reasonable and prudent step. Without such an accelerated replacement effort, it is our opinion that Columbia will face the risks associated with an ever increasing number of gas leaks due to corrosion. Columbia has advised Black & Veatch that there were areas of its territory that have corrosion leak rates on mains that are far higher than Columbia's system average.

Of Columbia's 493 miles of unprotected bare steel main remaining in service, Columbia has advised us that some of these mains were installed between 1900 and 1910. These mains have been exposed to underground external corrosion elements for 100 years. Columbia has 63 miles installed before 1930 and 73 miles installed between 1930 and 1939. Another 137 miles were installed between 1940 and 1949 and they have been in the ground for at least 59 years. 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 coated 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.

Over the past ten years Columbia replaced its unprotected bare and coated steel mains at an average rate of 9.4 miles per year or 1.9% per year. At this rate, it would take the Company 52 years to eliminate its higher risk mains. At a 52 year replacement rate, Columbia's newer vintage higher risk mains installed in the 1960's, would be at least 91 years old when they are replaced. We believe that an accelerated, well planned mains replacement program, such as Columbia's is needed to prevent potentially excessive leak rates and maintain a safe and reliable distribution system.

Findings – Natural Gas Services

In 2007 Columbia reported that there were 14,137 unprotected bare steel services remaining on its distribution system. They represent 10% of Columbia's total number of gas services.

Based on the leak management measure of the number of annual gas leaks due to corrosion on services per 1,000 non-cathodically protected bare and coated steel services, in 2007 Columbia had a much higher leak rate (61.8 per 1,000) compared to the weighted average value for regional (12.5) and national (10.4) companies (not including Columbia) that reported having 50 miles or more of unprotected bare steel main in their distribution systems.

Due to the close proximity of a natural gas service line to a home or business, leaks on services have the potential to create greater risks than a similar leak on a main. It is Black & Veatch's opinion that due to the higher level of corrosion leaks on services compared to the weighted average national and regional companies, Columbia, as part of its accelerated mains and services program, should further evaluate the current gas service corrosion leak situation and its plans for replacing these services.

Conclusions

It is our opinion that it is in the best interest of Columbia's customers that it identify and prioritize its high risk mains and services for replacement and accelerate the replacement of these mains and services before the leak rates gets out of hand. The replacement of Columbia's higher risk mains and services should be performed in a 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 riskier and harder to manage leak rate.

In addition to the customer safety and system reliability benefits mentioned throughout this report, a well planned accelerated mains and services replacement program would have a host of qualitative benefits for the public. These benefits include 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 mode that protects the customer, assures the integrity of the gas system, and does not cause unnecessary inconveniences for customers.

Based on the data comparisons completed by Black & Veatch, its interviews with Columbia operating staff regarding the management of its corrosion leaks, and its understanding of the Company's plan for an accelerated mains and services replacement program, in our opinion the Company thus far has been a good manager of its gas system in the area of corrosion leakage rates on mains. Black & Veatch recognizes and supports Columbia's concern for the safety of its customers and employees, as well as its desire to be a good steward of the gas system it operates.

We believe that in order for Columbia to continue to be a good operator of its gas system, a systematic accelerated replacement of its higher risk mains and services is prudent.

Black & Veatch recommends that the Kentucky Public Service Commission support and approve the implementation of Columbia's accelerated mains and services replacement program.

PURPOSE OF THE REPORT

Columbia Gas of Kentucky, Inc. ("Columbia" or the "Company") is considering requesting approval from the Kentucky Public Service Commission for an annual rate adjustment mechanism that would support its accelerated mains and services replacement program. This program would target Columbia's underground non-cathodically protected (unprotected) bare and coated steel, and cast iron mains, and unprotected bare and coated steel 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 volume of leak repairs remains manageable and that safety and reliability of its distribution system 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 iron mains; and c) non-cathodically protected bare and coated steel services.

THE DATA UTILIZED

Subject to the limitations set forth herein, this report was prepared for Columbia by Black & Veatch and is based on information not within the control of Black & Veatch. Black & Veatch has not been requested to make an independent analysis, to verify the information provided to us, or to render an independent judgment of the validity of the information provided by others. As such, Black & Veatch cannot, and does not, guarantee the accuracy thereof to the extent that such information, data, or opinions were based on information provided by others.

In performing the analyses, Black & Veatch utilized data from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Office of Pipeline Safety ("DOT") web site, as well as Black & Veatch's calculations using this data.

Department of Transportation Data

Natural 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 October 20, 2008, included the following data for individual companies for the years 1998 through 2007:

- 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. We also made a similar assumption regarding corrosion leaks on gas services.

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 that has been provided by Columbia which identified that 96% of all its corrosion leaks on mains in 2007 occurred on bare steel mains. More specifically, operating experience leads one to conclude that:

- Mains that are cathodically protected are generally protected from corrosion leaks (while they occasionally develop corrosion leaks if cathodic protection measures fail);
- 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 include comparisons related to:

- Annual change in unprotected bare and unprotected coated steel mains inventory.

[2] Pipeline and Hazardous Materials Safety Administration

- Annual change in corrosion leaks eliminated or repaired
- Annual number of corrosion leaks eliminated or repaired per mile of unprotected bare and unprotected coated steel main.
- Leak causes
- Types of pipeline material
- Annual number of corrosion leaks eliminated or repaired per 1,000 unprotected 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.

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 2007 database contained data for 1,426 companies.
- Most of the companies that filed with the DOT do not have unprotected bare steel mains or have a very small amount of bare steel mains compared to Columbia.
- DOT Database Nationwide Sorting Criterion – Black & Veatch utilized a sorting criterion intended to limit the focus to companies with a significant amount of unprotected bare steel, yet still incorporate a reasonable sample of companies. The sorting criterion chosen was all companies with a minimum of 50 miles of unprotected bare steel in 2007. Additional data which reinforced the reasonableness of this sorting criterion included:
    - Nationwide, 85 companies, including Columbia, meet the 50 miles of unprotected bare steel sorting criterion. They are listed in Appendix A to this report. Generally, these are also companies that are larger in size than the average company reporting, as measured by the number of gas services (70 have more that 50,000 services), and are subject to state regulatory oversight similar to Columbia.
    - The 85 nationwide companies meeting the sorting criterion operate 97% of the unprotected bare steel in the DOT 2007 database (50,487 miles out of 52,111 miles).
- Regional Analysis – In addition to the sorting criterion of 50 miles, Black & Veatch determined that Columbia data might also be reasonably compared to companies in reasonably close regional proximity to Columbia. Companies in Kentucky and states that border Kentucky 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: Illinois, Indiana, Kentucky, Missouri, Ohio, Tennessee, Virginia and West Virginia.
    - There are 19 companies, including Columbia, that meet the sorting criterion and are located in the eight regional states. They are listed in Appendix B.
    - The 19 regional companies meeting the sorting criteria represent 26% of the unprotected bare steel in the DOT 2007 database.

FINDINGS AND OPINIONS

1. Pipeline Corrosion Science and Natural Gas Industry Data

Black & Veatch's opinions stated throughout this report are supported by our gas distribution industry experience and data. 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 non-cathodically protected 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 the pipe 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 1. 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.

CORROSION IN DISTRIBUTION SYSTEMS CHAPTER IV

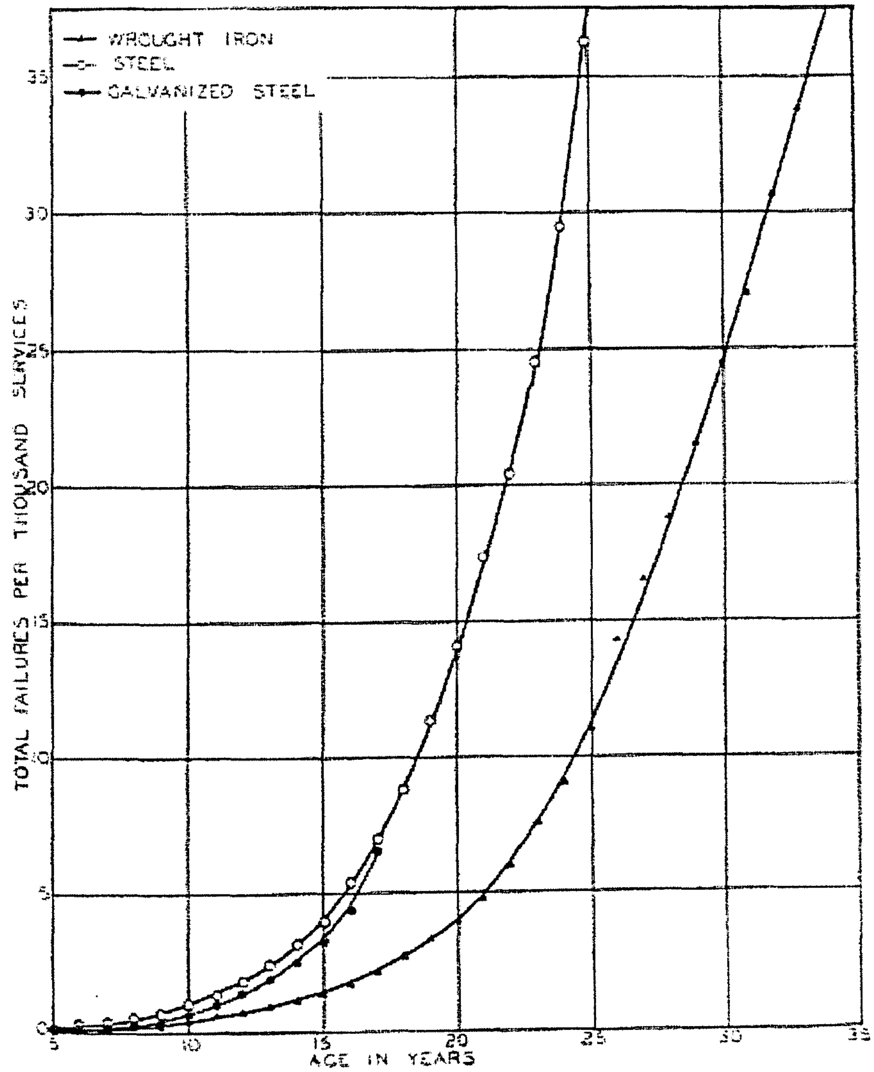


Fig. [illegible] Failure curves of house services in the Philadelphia Gas Works System.

Figure 1 - 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 2 below.

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.

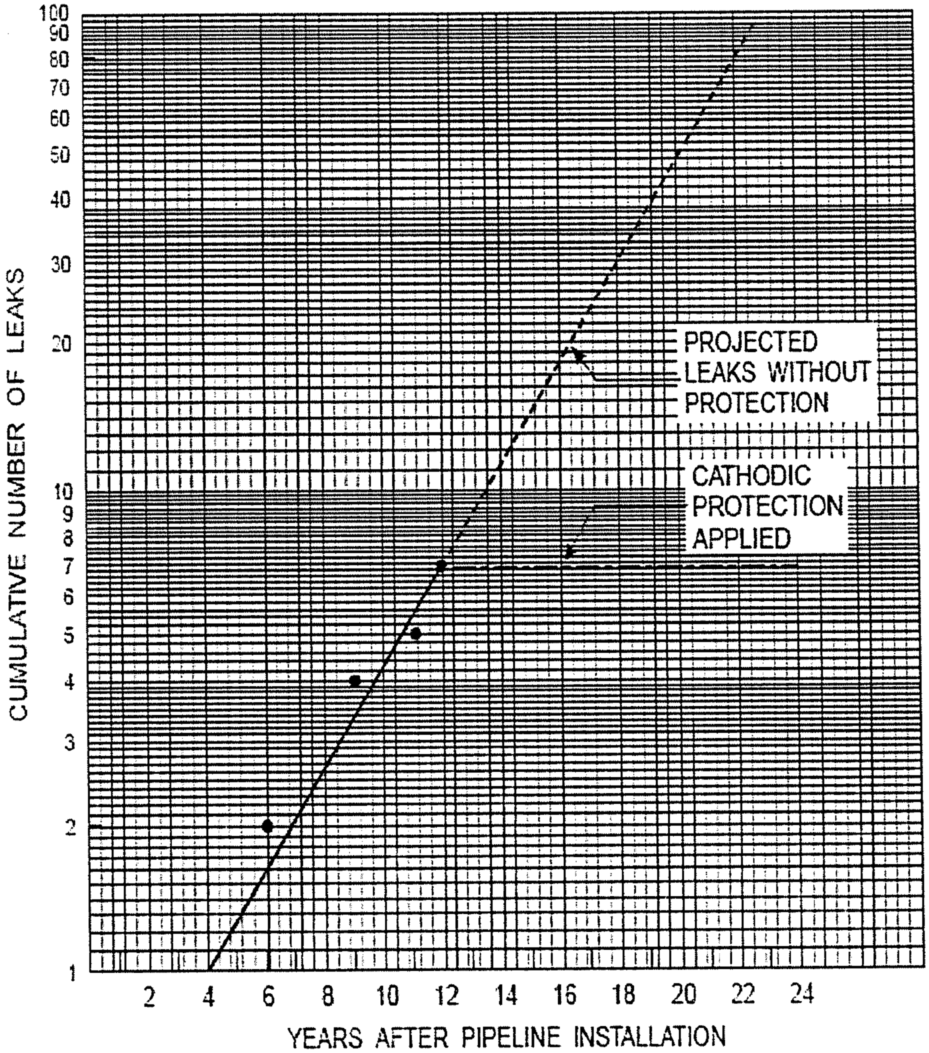


Figure 15.1 Cumulative number of leaks without CP.

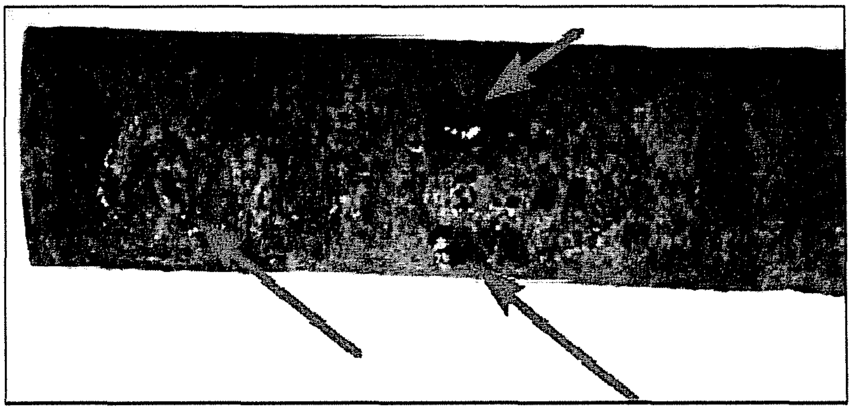
Figure 2 - Chart from 2001 text showing exponential leak rates for bare steel pipe in gas service.

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 3. 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 3 - Excerpt from U.S. Department of Transportation 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 non-cathodically protected bare steel pipelines.

The first photo (Figure 4) shows a section of 6" diameter unprotected bare steel main that was replaced by Columbia in 2006. When it was cleaned of dirt and scale, it revealed a previously installed leak repair clamp, as well as numerous corrosion holes along the pipe.

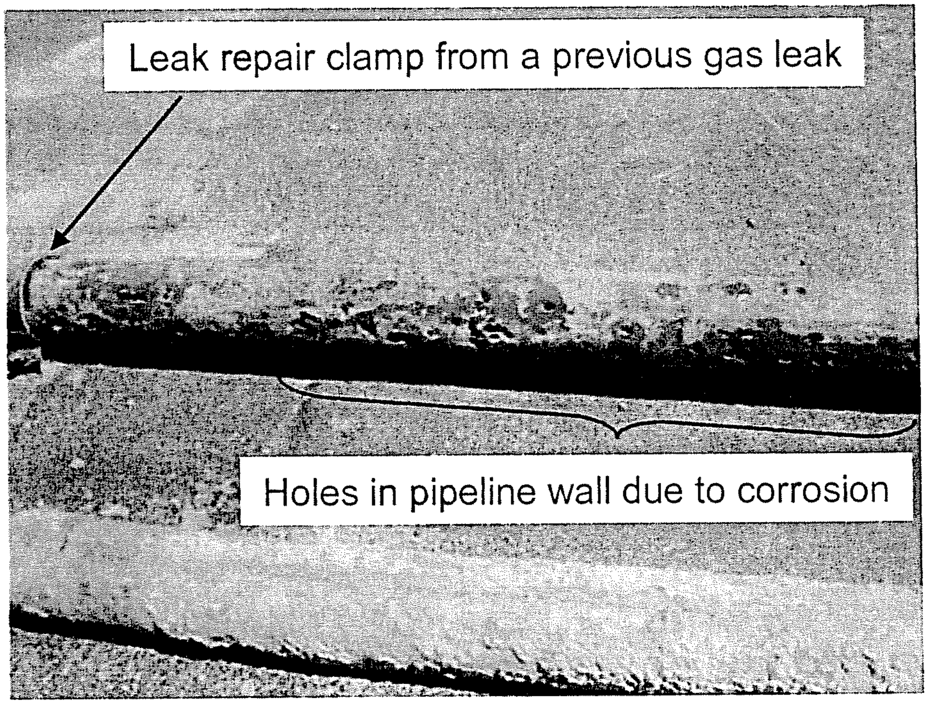


Figure 4
6" diameter unprotected bare steel main that was replaced by Columbia in 2006

In the second photo (Figure 5), Columbia illustrates the size of the corrosion holes in the 6" diameter unprotected bare steel main by comparing them to a 25 cent coin (which is approximately 1" in diameter).

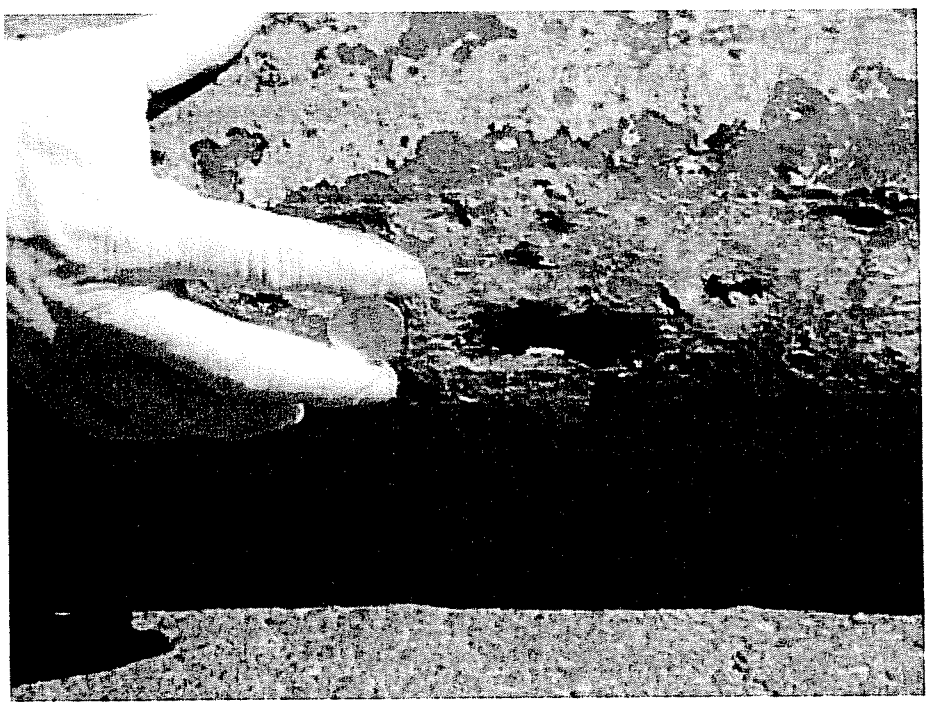


Figure 5
6" diameter unprotected bare steel main that was replaced by Columbia in 2006

2. 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.

For 2007 Columbia reports that it operates 52 miles of transmission pipeline and that it has no unprotected bare or coated steel transmission pipe.

Regarding distribution pipelines, DOT 2007 data shows that Columbia reported having 493 miles of unprotected bare steel and no miles of unprotected coated steel mains remaining in its system (Figure 6). Unprotected bare steel accounts for 19% of Columbia's total inventory of distribution mains. It can also be seen from Figure 6 that Columbia has 25 miles of cast iron main or 1% of Columbia's inventory of mains.

Columbia: Miles of Main in Inventory by Type of Material - DOT 2007

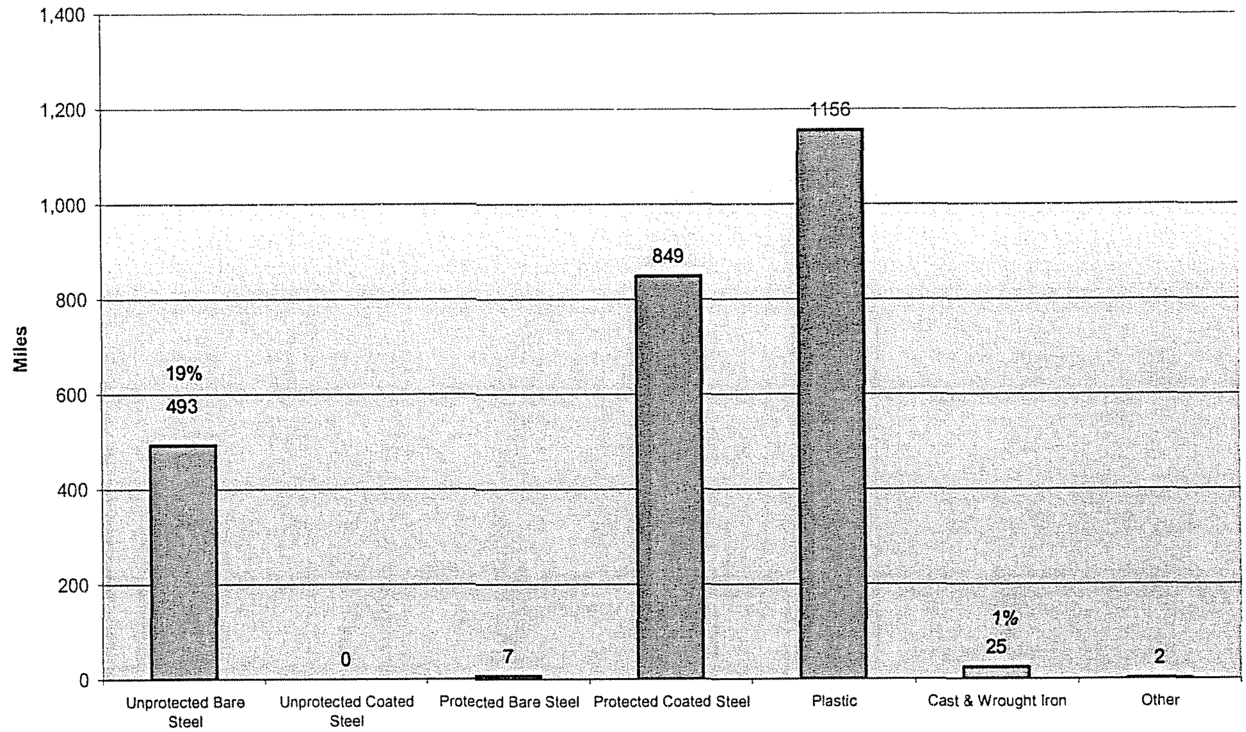


Figure 6

3. Miles of Unprotected Bare Steel Main Comparison - 2007

Figure 7 illustrates Columbia's miles of unprotected bare steel compared to national and regional companies reporting 50 or more miles of unprotected bare steel main.

Columbia's 493 miles of unprotected bare steel mains in 2007 ranked as the 24th highest out of the 85 companies in the DOT database with 50 miles or more of unprotected bare steel in their systems.

Columbia: Total Miles of Bare Steel Main Compared to Companies with 50 Miles or More of Unprotected Bare Steel Main Reported for 2007

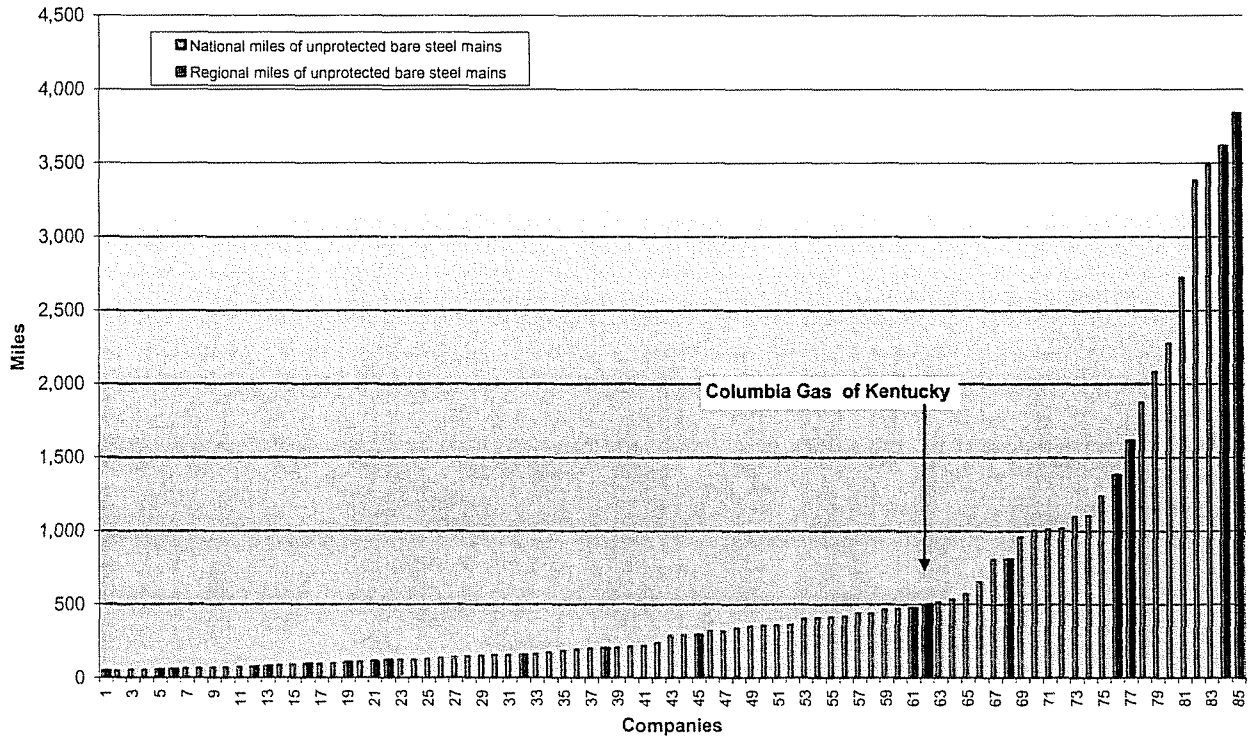


Figure 7

4. Columbia's Miles of Main by Year Installed

The number of years that these mains have been buried in the ground is a contributing factor to an ever increasing amount of corrosion leaks over time. "The ways in which the age of a pipeline can influence the potential for failures are through specific failure mechanisms such as corrosion and fatigue, or in consideration of changes in manufacturing and construction methods since the pipeline was built."[3]

Figure 8 illustrates the number of remaining miles of mains, by decade installed in Columbia's system. From this chart one can see that some of these mains were installed between 1900 and 1910. These mains have been exposed to underground external corrosion elements for 100 years. Columbia has 63 miles installed before 1930 and 73 miles installed between 1930 and 1939. Another 137 miles were installed between 1940 and 1949 and they have been in the ground for at least 59 years.

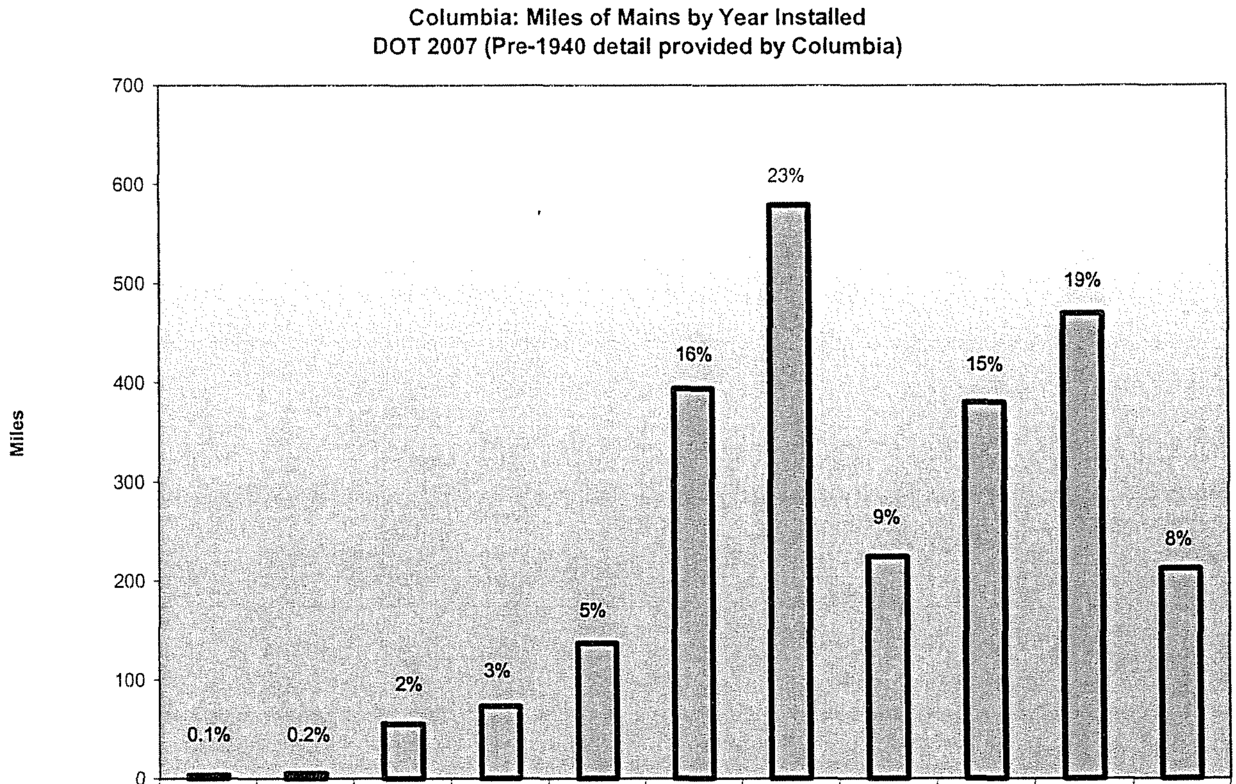
Due to the technology used at the time we assume that these pre-1950 mains represent 53% of its higher risk mains.

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 coated 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 its unprotected 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 493 miles of bare steel main in service today was installed prior to 1959.

Columbia's practice of installing these main materials during the decades illustrated on the chart is consistent with the pipeline technology at the time.

[3] "Pipeline Risk Management Manual" by W. Kent Muhlbauer, Third Edition, page 30



	1900-1909	1910-1919	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009
Miles of main	3	5	55	73	137	394	579	224	380	470	212

Figure 8

5. Columbia's Number of Gas Leaks Due to Corrosion on Mains and Services as a Percent of Total Leaks (Excluding Leaks caused by Third Party Excavation)

During 2007, Columbia reported experiencing 375 gas leaks that were eliminated or repaired on mains (excluding leaks caused by excavation). Of these leaks, gas leaks due to corrosion on mains accounted for 246 or 66% of the Company's total number of leaks on mains.

Figure 9 illustrates for the period 1998 through 2007, the percentage each year of gas leaks due to corrosion on mains to total leaks eliminated on mains (excluding leaks caused by excavation). Figure 10 also illustrates the percentage each year of gas leaks due to corrosion on services to total leaks eliminated on services (excluding leaks caused by excavation).

The weighted average of Columbia's gas leaks due to corrosion on mains to total leaks eliminated on mains (excluding leaks caused by excavation) over the ten-year period was 73% and 72% for services.

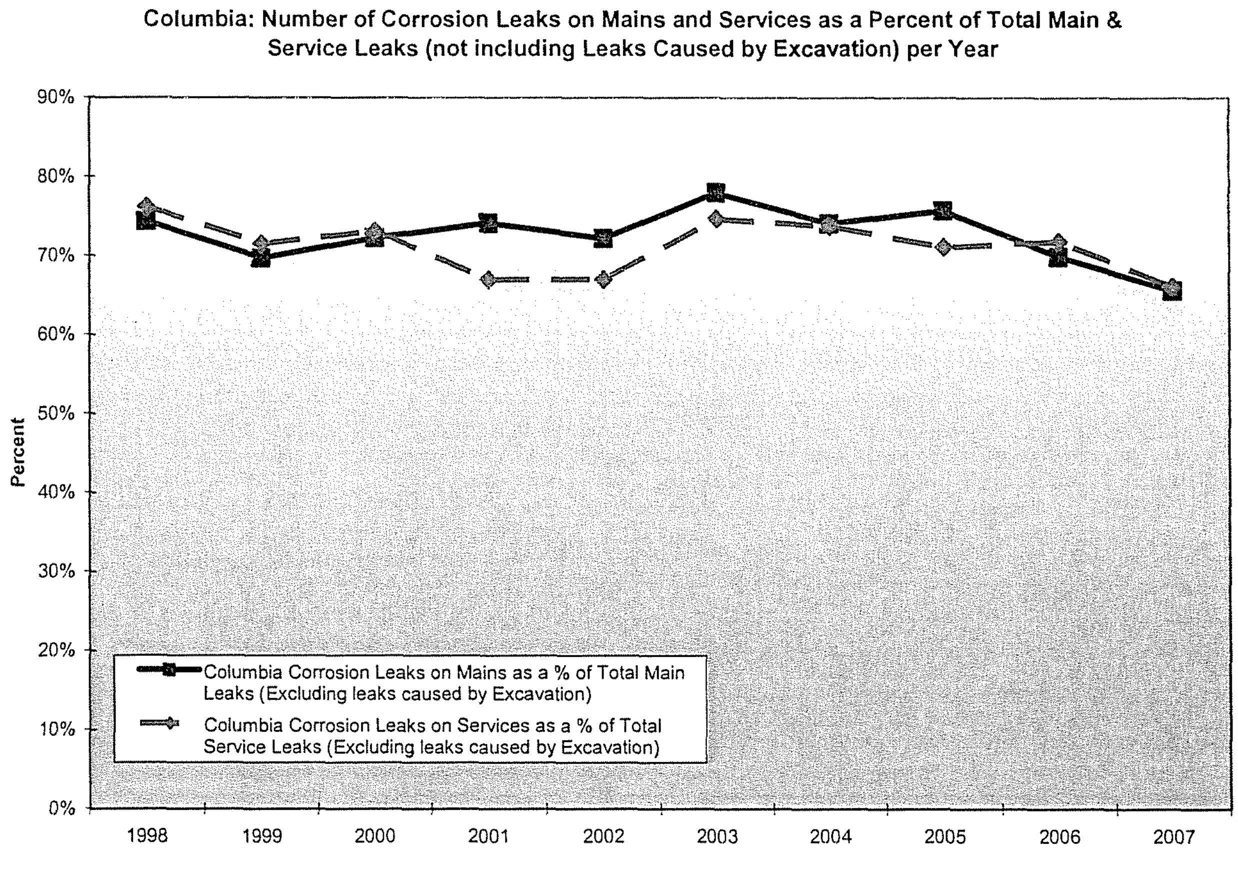


Figure 9

6. Total Number of Gas Leaks Due to Corrosion Repaired or Eliminated on Distribution Mains Comparison - 2007

In 2007, Columbia reported that it repaired or eliminated 246 gas leaks on mains that were caused by corrosion. Columbia's level of gas leaks due to corrosion on mains in 2007 ranked as the 37th highest out of the 85 companies in the DOT database with 50 miles or more of unprotected bare steel in their systems. This fact is illustrated in Figure 10.

In 2007, Columbia had more corrosion leaks on mains compared to all other Kentucky gas distribution operators reporting to the DOT.

The comparison of the leak management measure: the number of corrosion leaks repaired or eliminated on mains per mile of unprotected bare and coated steel main is discussed in Section 9.

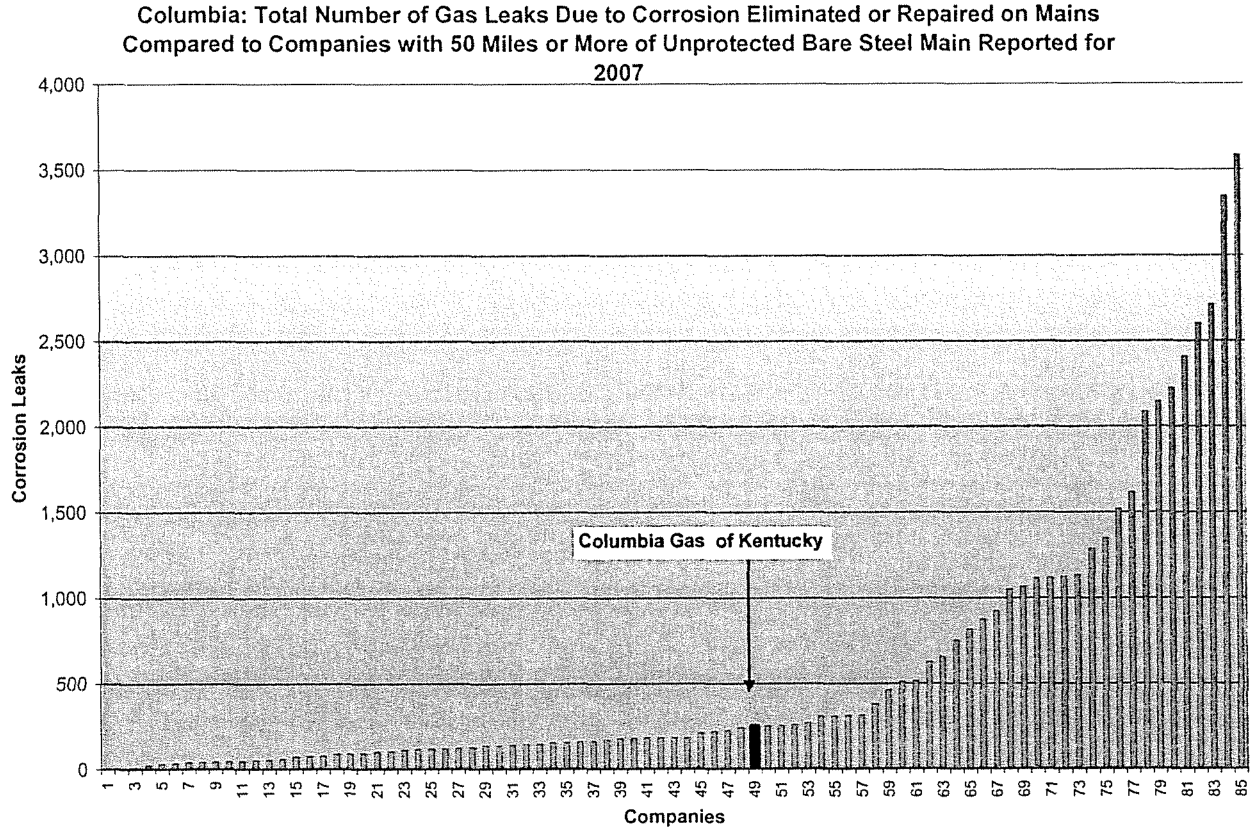


Figure 10

7. Total Number of Gas Leaks Due to Corrosion on Mains Compared to the Number of Miles of Unprotected Bare and Coated Steel Mains in Inventory 1998 - 2007

Figure 11 illustrates the reduction in Columbia's miles of unprotected bare steel and unprotected coated steel mains inventory and the change in the number of gas leaks due to corrosion repaired or eliminated on mains for the period 1998 through 2007.

For the period 1998 through 2007 the average replacement rate was 9.4 miles per year (1.9%), which if extrapolated would result in the replacement of its unprotected bare steel system in approximately 52.2 years.

While Columbia plans to replace mains based on their risk priority, if for example a plan to remove the oldest mains first was implemented, at Columbia's replacement rate over the past ten years, the last pipe to be replaced would be older than 91 years[4].

Columbia: Number of Gas Leaks Due to Corrosion Eliminated or Repaired on Mains and Unprotected Bare and Unprotected Coated Steel Main Inventory

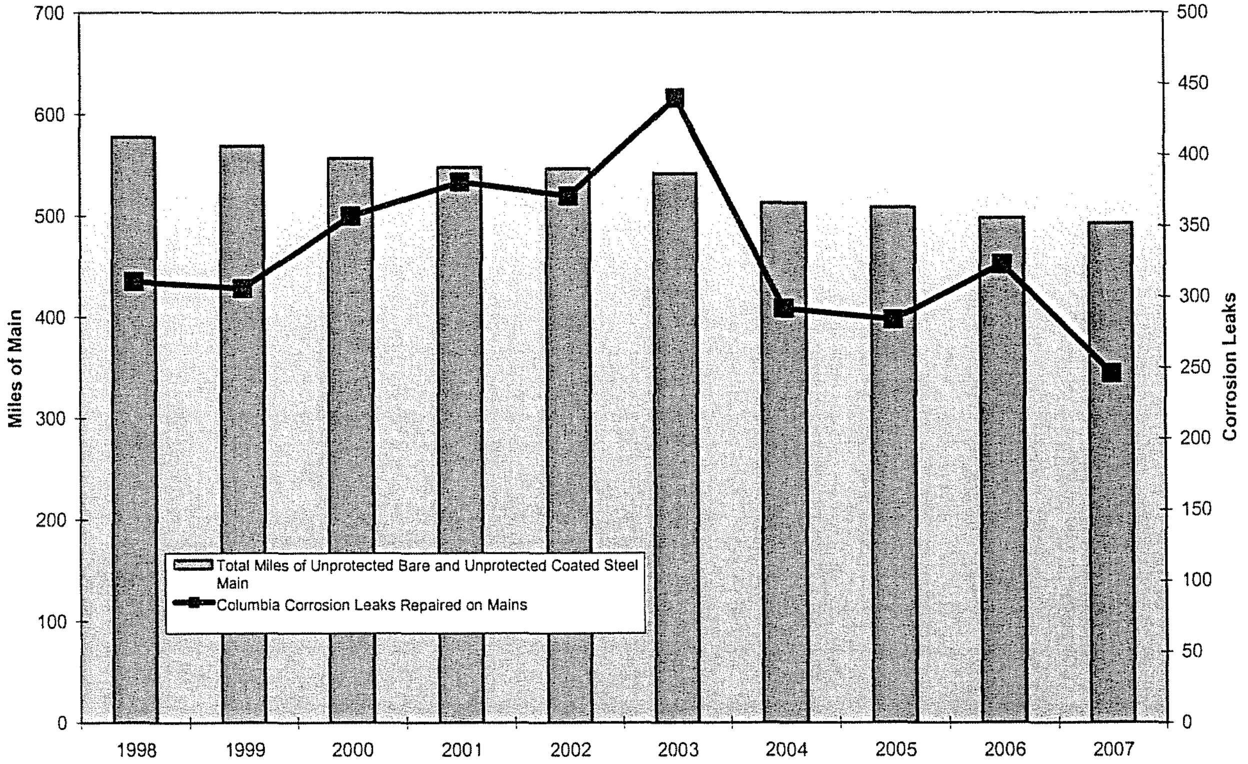


Figure 11

[4] Assumes last pipe to be replaced was installed in 1969

8. Columbia's Change in the Number of Gas Leaks Due to Corrosion on Mains 1998 - 2007

The Company's number of gas leaks due to corrosion repaired or eliminated on mains for the period 1998 through 2007, compared to the average number of gas leaks due to corrosion repaired or eliminated on mains for regional companies with 50 miles or more of unprotected bare steel main in their systems is illustrated in Figure 12.

From this graph, one can see that while the average of gas leaks due to corrosion repaired or eliminated on mains for regional companies is below its 1998 and 1999 levels. Since 2000, the number of gas leaks due to corrosion repaired or eliminated on mains for regional companies has increased slightly. During this period Columbia's corrosion leaks repaired or eliminated on mains have trended slightly lower.

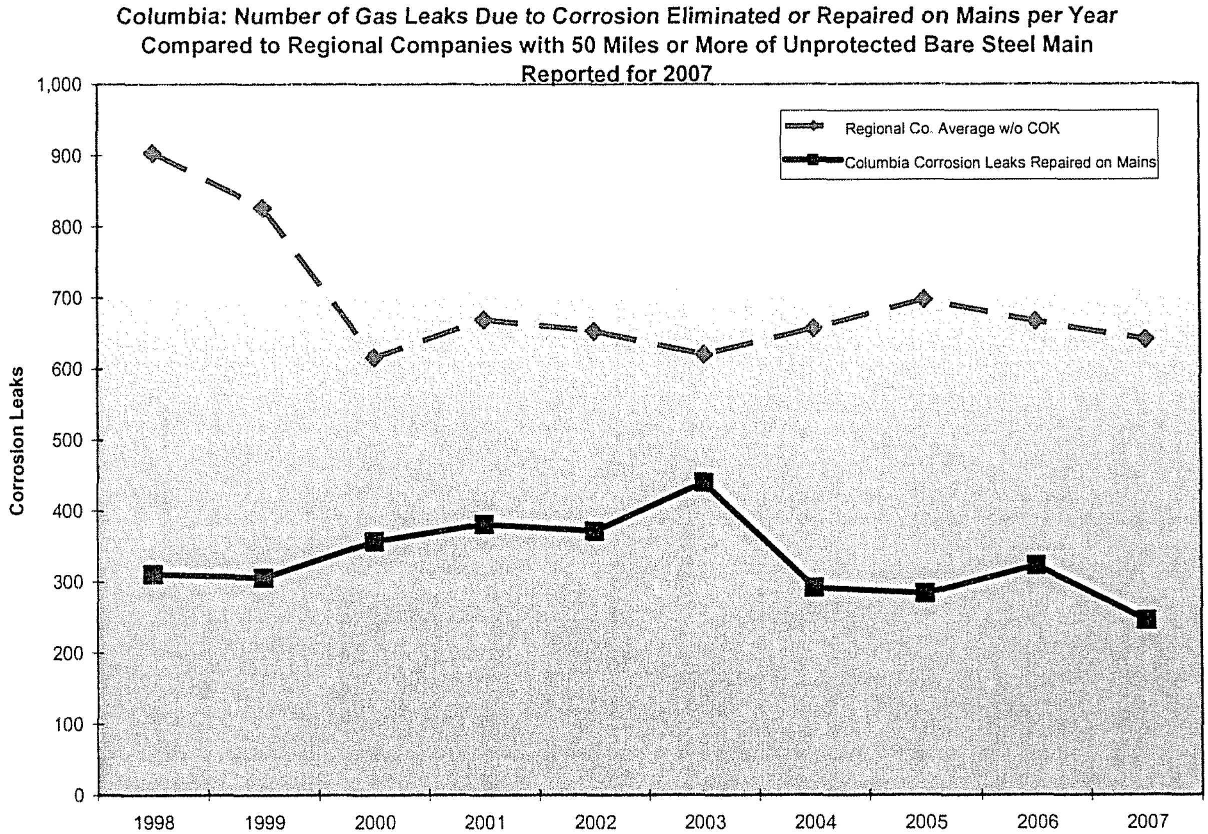


Figure 12

9. The Number of Gas Leaks Due to Corrosion Repaired or Eliminated on Mains per Mile of Unprotected Bare Steel and Unprotected Coated Steel Main – 2007

The number of gas leaks due to corrosion repaired or eliminated on mains experienced by an individual company is a function both of the number of miles of aging unprotected pipelines that they have remaining in its system and the condition of those pipes. Companies with larger amounts of aging unprotected pipelines may typically experience a larger number of leaks due to corrosion.

In order to normalize this data we utilize the measure of the number of gas leaks due to corrosion repaired or eliminated on mains per mile of unprotected bare and unprotected coated steel main. This is a frequently used metric to help understand the condition of these mains in a natural gas distribution system. Figure 13 compares for 2007, this measure for national and regional companies that have 50 miles or more of unprotected bare steel main remaining in their system.

In Figure 13, one can observe that Columbia's rate of 0.50 is better than the region and national weighted averages. The weighted average rate of the regional companies is 0.717 and weighted average rate of the national companies is 0.725 (not including Columbia). Figure 13 illustrates the corrosion leak rates for individual companies.

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 practices of installing at the time of a repair of a corrosion leak on a bare steel main, (or when an unprotected steel main is exposed), one or more directly connected magnesium anodes (depending on the length of main exposed. This practice of installing anodes only delays the eventual and inevitable demise of these mains at those hot spots. In time, these anodes will be consumed, the mains will continue to suffer from the corrosion process and resume creating new leaks. The Company also maintains a database 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.

The Company is also currently implementing a pipeline integrity management decision support software tool called Optimain. This dynamic system-wide risk assessment tool will help Columbia prioritize the mains that need to be replaced and thus help to optimize capital spending.

All of these practices have helped Columbia manage its number of corrosion leaks on mains. However, as discussed further in this report, unless these unprotected aging mains are either retired or replaced, Black & Veatch believes Columbia will experience an increase of its corrosion leak rate as these mains continue to suffer the effects of corrosion.

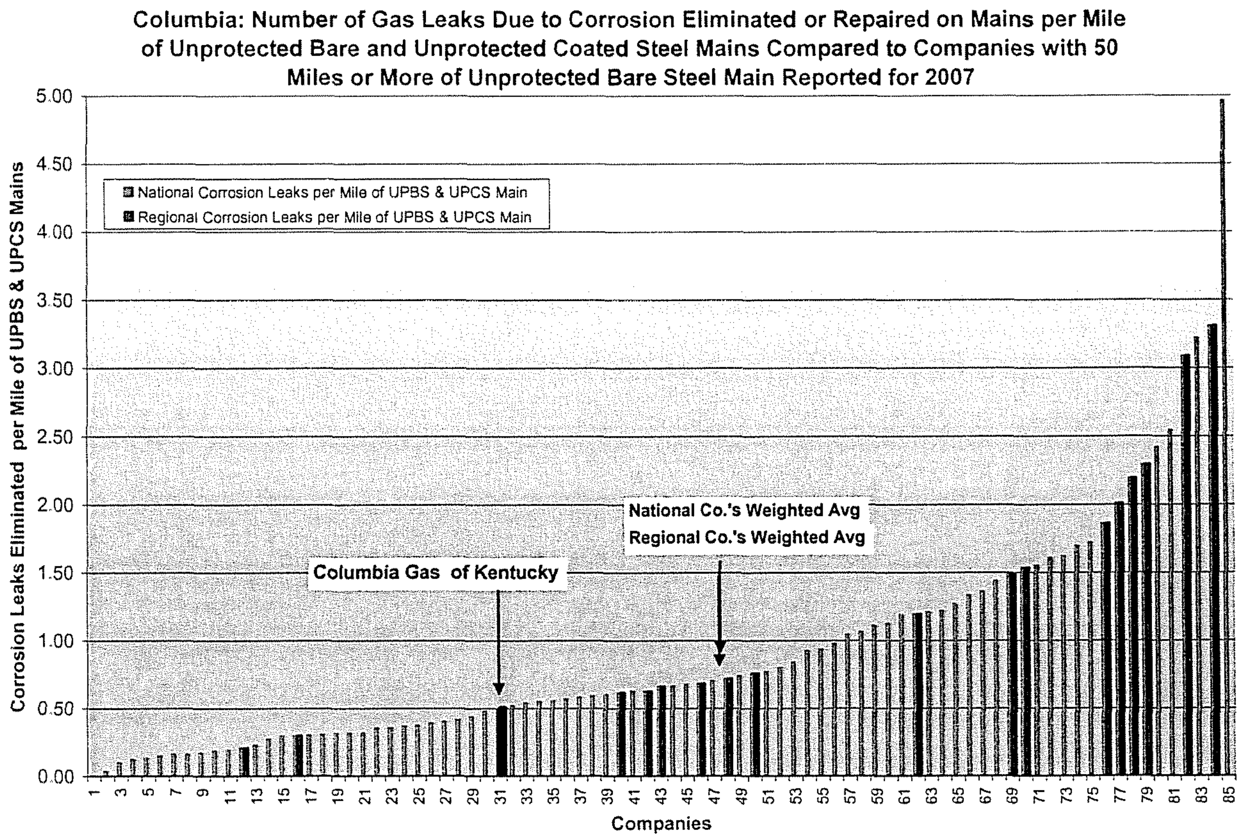

Columbia: Number of Gas Leaks Due to Corrosion Eliminated or Repaired on Mains per Mile of Unprotected Bare and Unprotected Coated Steel Mains Compared to Companies with 50 Miles or More of Unprotected Bare Steel Main Reported for 2007
National Corrosion Leaks per Mile of UPBS & UPCS Main
Regional Corrosion Leaks per Mile of UPBS & UPCS Main
Corrosion Leaks Eliminated per Mile of UPBS & UPCS Mains
Columbia Gas of Kentucky
National Co.'s Weighted Avg
Regional Co.'s Weighted Avg
Companies

Figure 13

10. The Change in the Number of Columbia's Gas Leaks Due to Corrosion Repaired or Eliminated on Mains per Mile of Unprotected Bare Steel and Unprotected Coated Steel Main 1998 - 2007

The plot of Columbia's number of gas leaks due to corrosion repaired or eliminated on mains per mile of unprotected bare steel and unprotected coated steel main and the regional companies for the period 1998 through 2007 is presented in Figure 14.

It is apparent that the Company's 2007 corrosion leak rate per mile (0.50) appears favorable compared to the weighted 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 2007 weighted average leak rate (0.72) for the 18 regional companies with more than 50 miles of unprotected bare steel (not including Columbia), that would mean that Columbia's annual number of corrosion leaks on mains would increase from 246 to 357 leaks. This would be a 45% increase in the number of leaks compared to Columbia's 2007.

Black & Veatch believes that such higher levels of gas leaks due to corrosion add incremental risks to the public and Columbia. We support the Company's decision to begin an accelerated replacement program of its trouble prone mains to drive down the present 246 corrosion leaks on mains 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 areas of its service territory that experienced leak rates higher than the average annual corrosion leak rate (0.50 leaks per mile) for its entire system. One example is a 700 foot section of 6" unprotected bare steel main that experienced 4 corrosion leaks since 2003. This helps illustrate that Columbia's average leak rate will rise if its aging higher risk pipelines are not retired or replaced.

Black & Veatch believes that Columbia has done a good job to date in managing its corrosion leak rate on mains. We also believe that Columbia's unprotected bare steel mains ten-year average replacement rate of 1.9% per year, which yields a 52 year system replacement period, results in too many years to wait until these aging higher risk mains are removed or replaced. It is our opinion that in order for Columbia to continue to prevent corrosion leak levels from increasing, which would cause an increase in safety and reliability risks to customers and employees, as well as increases in operating and maintenance costs, it should begin to accelerate the retirement or replacement of these mains.

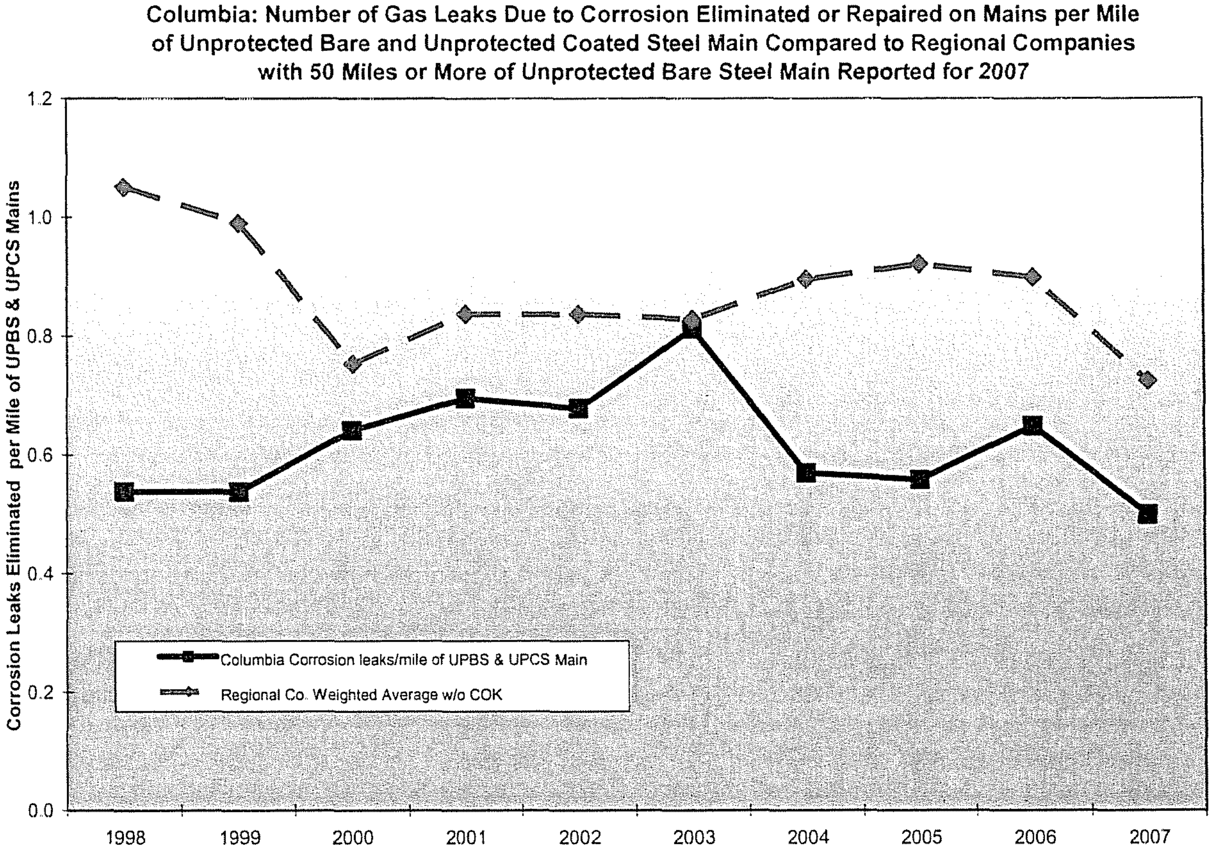

Columbia: Number of Gas Leaks Due to Corrosion Eliminated or Repaired on Mains per Mile of Unprotected Bare and Unprotected Coated Steel Main Compared to Regional Companies with 50 Miles or More of Unprotected Bare Steel Main Reported for 2007
Corrosion Leaks Eliminated per Mile of UPBS & UPCS Mains
1.2
1.0
0.8
0.6
0.4
0.2
0.0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
Columbia Corrosion leaks/mile of UPBS & UPCS Main
Regional Co. Weighted Average w/o COK

Figure 14

11. Columbia's Services by Material Type

Figure 15 illustrates Columbia's inventory of services by material type. In 2007, it reported having 14,137 unprotected bare steel (10% of all services) and no unprotected coated steel services remaining in its system.

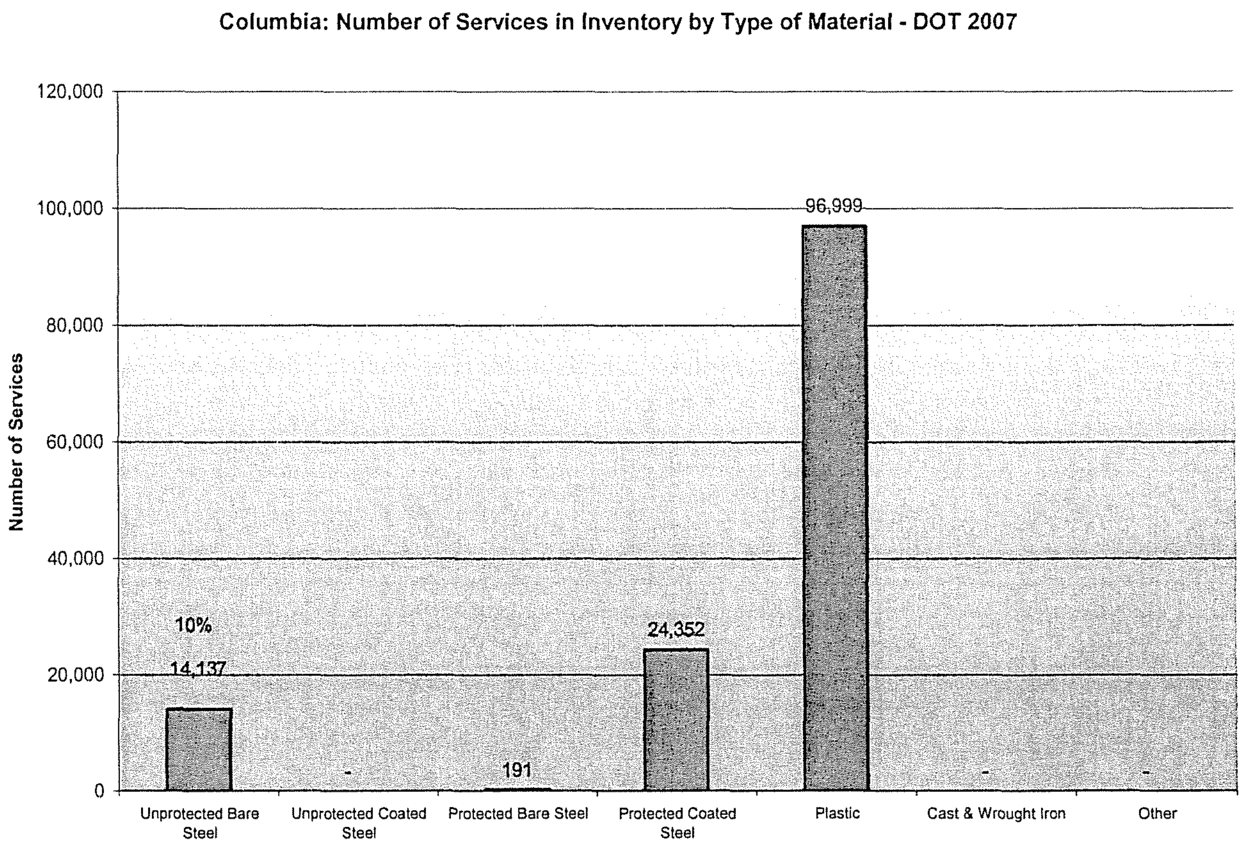


Figure 15

12. Columbia's Number of Unprotected Bare Steel Services Comparison - 2007

When comparing the number of unprotected bare steel services among the companies reporting having 50 miles or more of unprotected bare steel main in 2007, Columbia ranked 38th highest of 85 companies for the number of unprotected bare steel services (14,137) remaining in its system. This is illustrated in Figure 16.

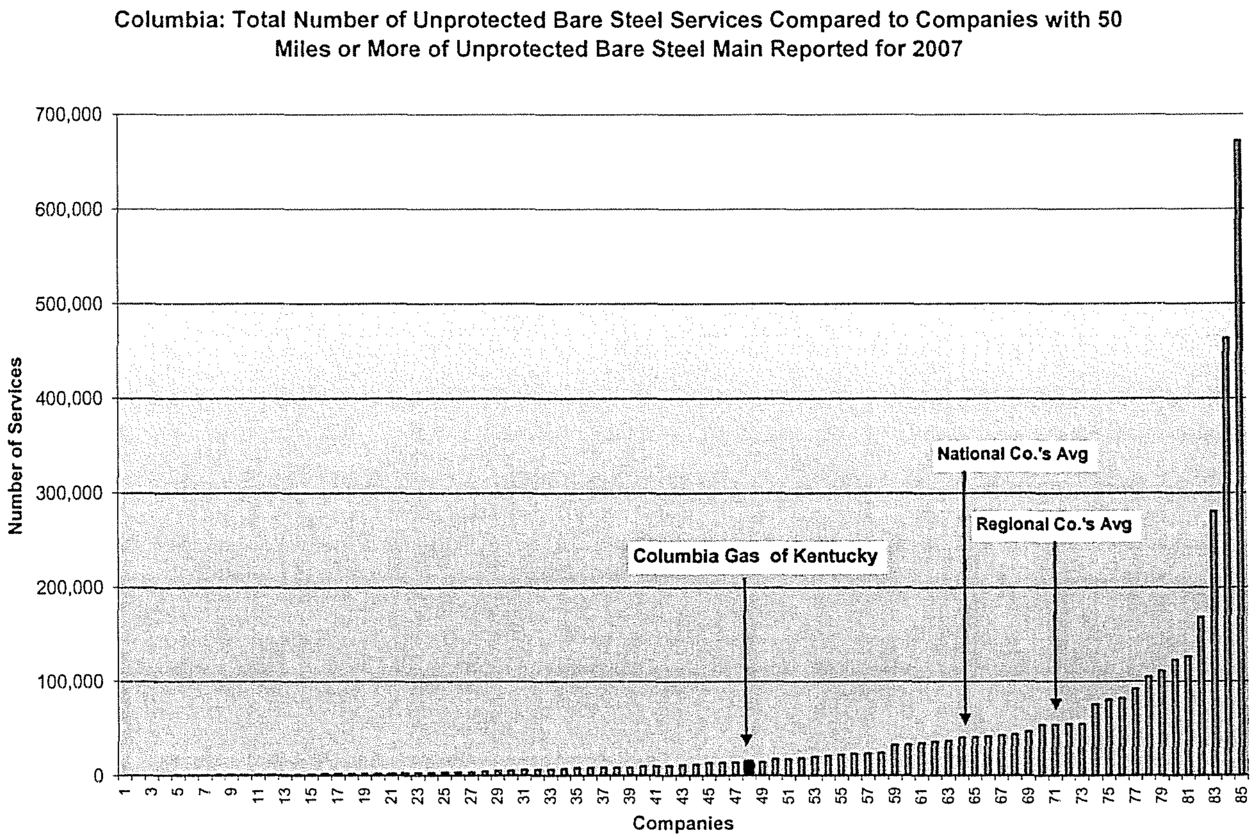


Figure 16

13. Total Number of Gas Leaks Due to Corrosion Repaired or Eliminated on Services Compared to the Number of Unprotected Bare and Unprotected Coated Steel Services in Inventory 1998 - 2007

Figure 17 illustrates the reduction in the number of Columbia's unprotected bare steel and unprotected coated steel services inventory and the change in the number of gas leaks due to corrosion repaired or eliminated on services for the period 1998 through 2007.

This chart clearly illustrates the relationship between the reduction of the number of Columbia's aging unprotected bare steel services and the corresponding reduction in gas leaks due to corrosion repaired or eliminated on services.

Extrapolating Columbia's 1998 through 2007 average rate of replacement (728 services per year) into the future would result in the replacement of its remaining unprotected bare steel service inventory in approximately 19.4 years.

An unprotected bare steel gas service installed in the same street and at the same time as an unprotected bare steel gas main is more likely to begin to experience corrosion leaks sooner than the mains. This is because unprotected bare steel gas service lines are smaller diameter pipes than gas mains and gas service lines have a thinner wall thickness than the gas main. As the corrosion process proceeds, the pipelines loose metal and the pipe walls become pitted and eventually the pits fully penetrate the wall causing a gas leak. It is intuitive that the high level of leakage due to corrosion presently experienced in Columbia's service population will be realized in the main population as corrosion continues.

Furthermore, due to the close proximity of the gas service line to a home or business, gas service leaks have the potential to create greater risks than a similar leak on a main.

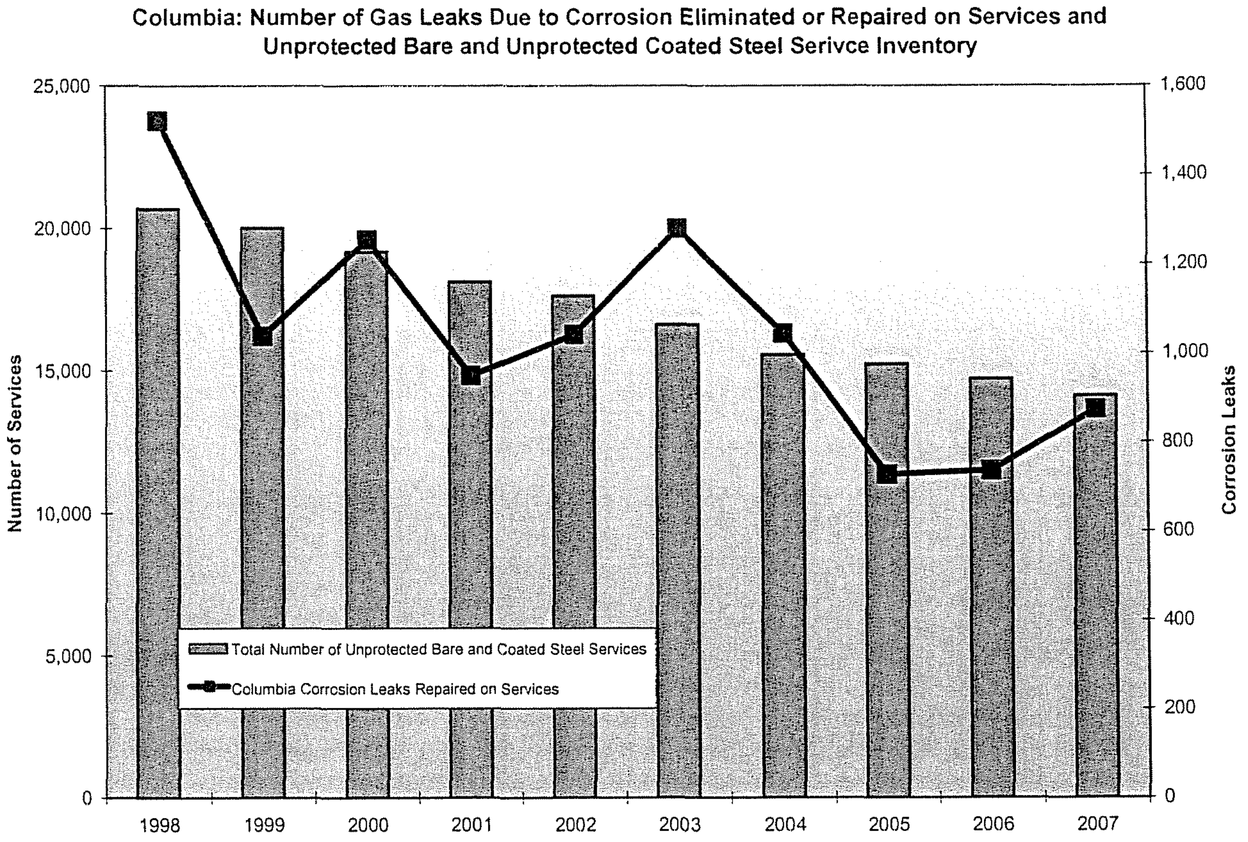

Columbia: Number of Gas Leaks Due to Corrosion Eliminated or Repaired on Services and Unprotected Bare and Unprotected Coated Steel Serivce Inventory
25,000
20,000
15,000
10,000
5,000
0
Number of Services
1,600
1,400
1,200
1,000
800
600
400
200
0
Corrosion Leaks
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
Total Number of Unprotected Bare and Coated Steel Services
Columbia Corrosion Leaks Repaired on Services

Figure 17

14. Change in the Number Columbia's Gas Leaks Due to Corrosion on Services 1998 - 2007

During the period 1998 through 2007, while the numbers of annual gas leaks due to corrosion eliminated or repaired on services are moving in the right direction (decreasing), Columbia experienced approximately the same number of gas leaks due to corrosion on services compared to the average of regional companies (Figure 18).

We note that while Columbia has a smaller number of unprotected bare steel services than the average of regional companies (Figure 16), it has approximately the same number of corrosion leaks. This is an indicator that Columbia's services are leaking at a higher rate than the regional companies. This is further discussed in the next section. We also note that Columbia's number of corrosion leaks repaired in 2007 increased by 138 (19%) over 2006.

In addition, as discussed previously (Figure 10) for the period 1998 through 2007 the weighted average of Columbia's corrosion leaks repaired on services was 72% of all service leaks repaired (excluding leaks caused by excavation).

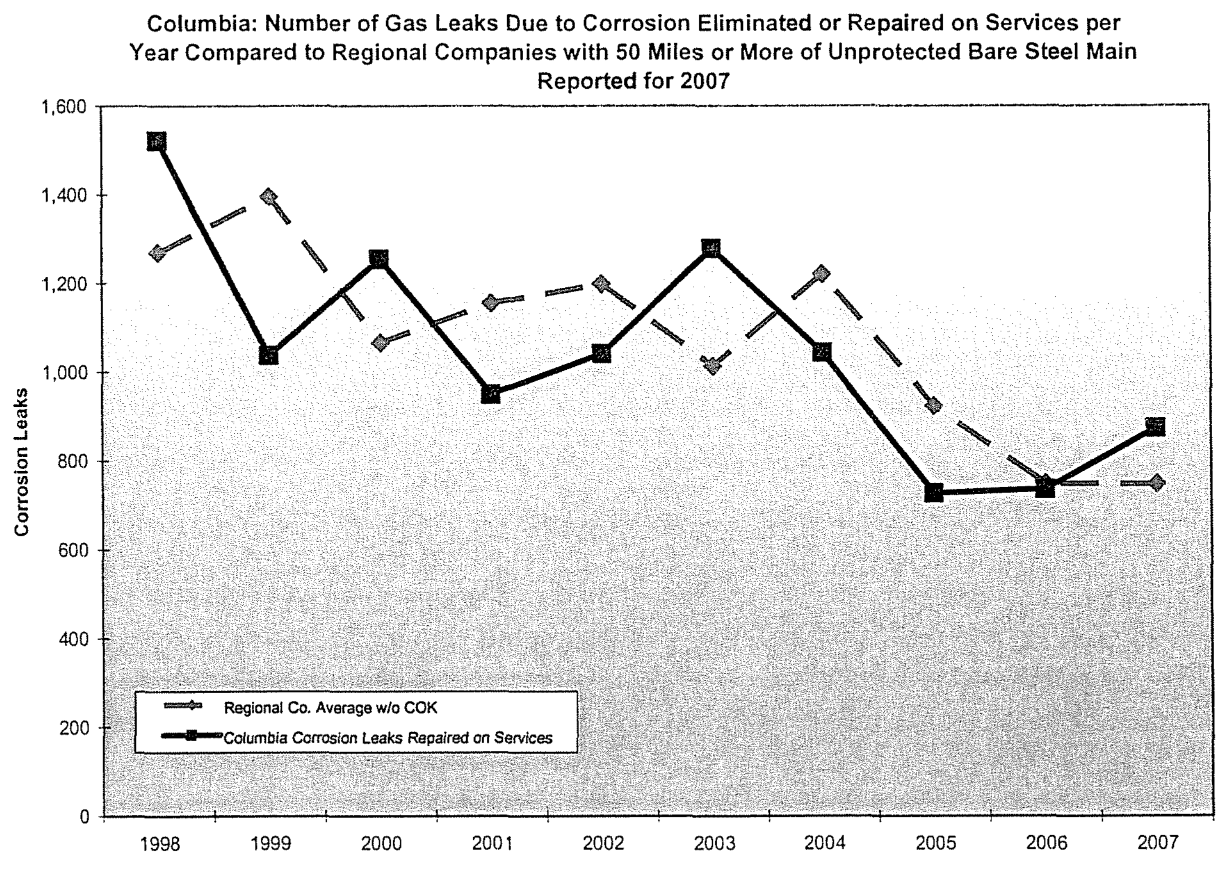


Figure 18

15. Columbia's Number of Gas Leaks Due to Corrosion Repaired or Eliminated on Services per 1,000 Unprotected Bare and Unprotected Coated Steel Services Comparison - 2007

Figure 19 illustrates for 2007, a comparison of the measure of the number of gas leaks due to corrosion repaired or eliminated on services per 1,000 unprotected bare and unprotected coated steel services between Columbia and companies with 50 miles or more of unprotected bare steel mains.

Columbia's corrosion rate of 61.8 gas leaks due to corrosion repaired or eliminated per 1,000 unprotected bare and unprotected coated steel services is higher than the weighted average of both national (10.4) and regional companies (12.5) with 50 miles or more of unprotected bare steel mains.

It is Black & Veatch's opinion that due to the higher level of corrosion leaks on services compared to the weighted average national and regional companies (as illustrated in Figures 19 and 20), Columbia, as part of its accelerated mains and services replacement program, should further evaluate the current gas service corrosion leak situation and its plans for replacing these services.

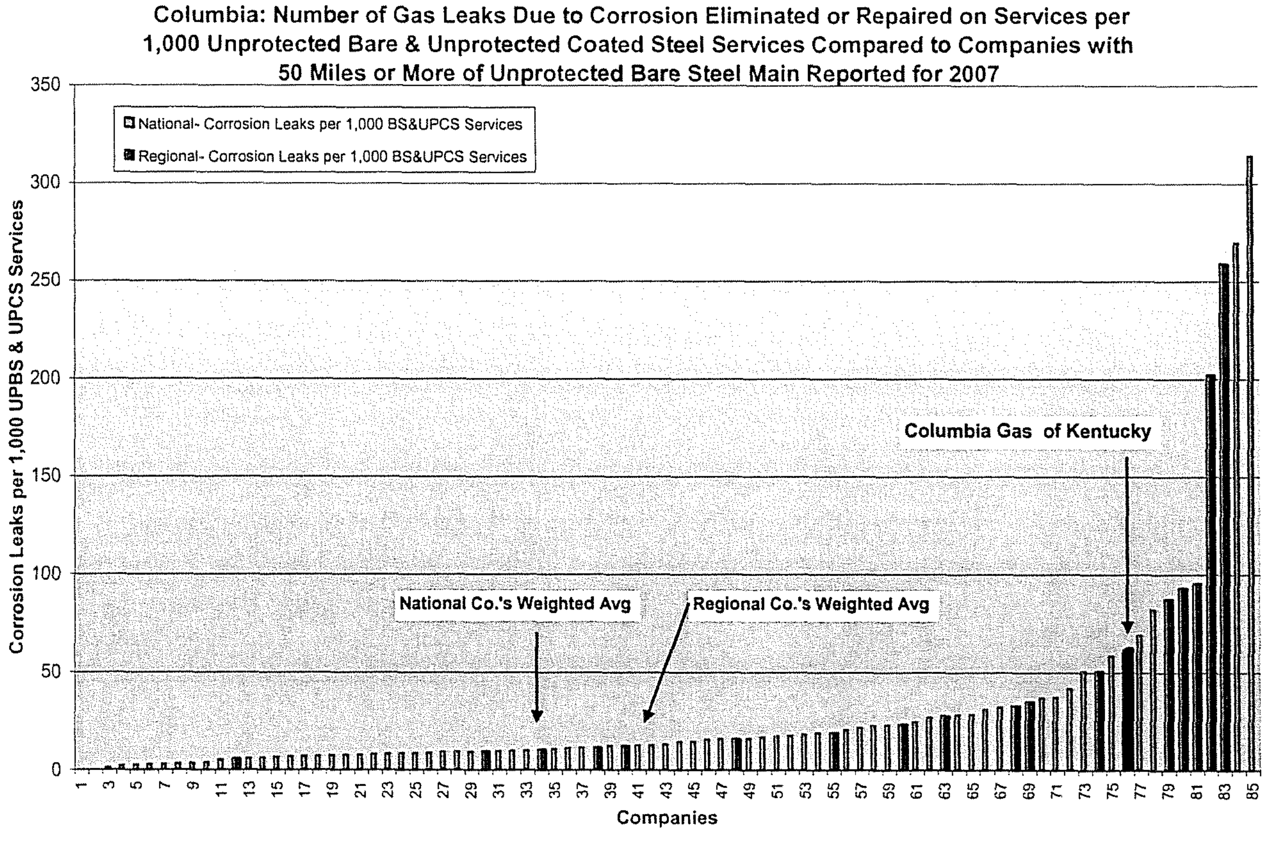


Figure 19

16. Change in Columbia's Number of Gas Leaks Due to Corrosion Repaired or Eliminated on Services per 1,000 Unprotected Bare Steel and Unprotected Coated Steel Services 1998 - 2007

The plot of Columbia's number of gas leaks due to corrosion repaired or eliminated on services per 1,000 unprotected bare steel and unprotected coated steel services and the regional companies for the period 1998 through 2007 is presented in Figure 20.

Throughout this period Columbia's corrosion leak rate was consistently higher than the weighted average of the corrosion leaks per 1,000 unprotected bare steel and unprotected coated steel services for the regional companies.

As discussed in Section 13, we believe that Columbia, as part of its accelerated mains and services replacement program, should further evaluate the current gas service corrosion leak situation and its plans for replacing these services.

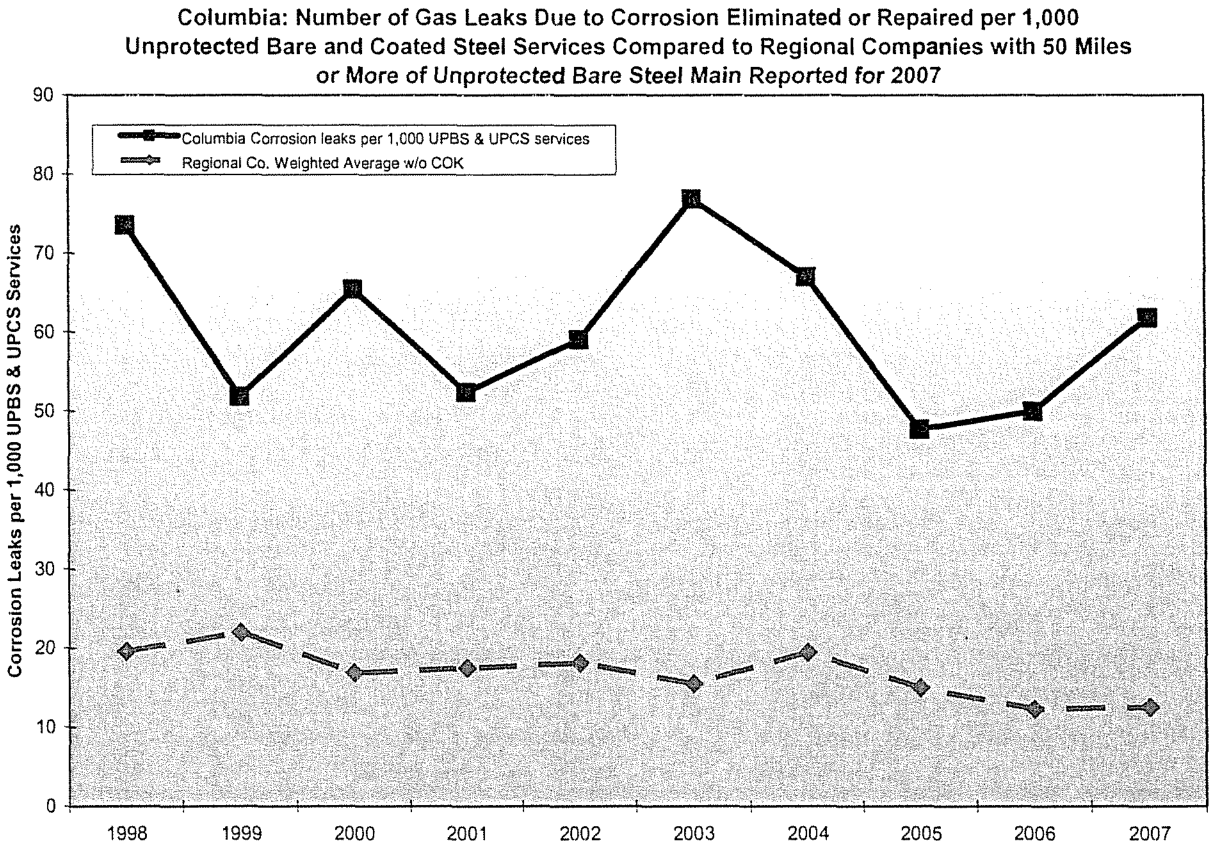


Figure 20

17. Columbia's Cast Iron Mains

The natural gas industry typically includes cast iron mains among its list of higher risk main materials, along with non-cathodically protected bare steel mains. These mains are among the oldest mains remaining in distribution systems dating back to the early 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 bell and spigot joints that were sealed with jute and lead caulking. Over time these joints may become dried out and due to the flexing of the pipe that may occur due to traffic vibration, seasonal weather, and nearby construction activities, these joints eventually leak. Of greater concern is the fact that cast iron mains are more brittle than steel mains and as such they are 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. Such leaks may also be hard to find as they may cause high gas readings at great distances from the actual leak site. 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 also has the potential of corroding (graphitization) under the right soil conditions, but is much more likely to leak at joints or crack in a brittle failure mode. Wrought iron pipes, while less brittle than cast iron mains, are subject to corrosion. A viewing of the chart provided in Figure 1 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 pipeline materials that will need to be replaced.

Columbia has 25 miles of cast iron remaining in service in its distribution system (Figure 6). Eighty percent (80%) or 20 miles of its cast iron mains are 4" in diameter or smaller in size. Smaller diameter cast iron mains have thinner wall thicknesses than larger diameter cast iron pipes and these smaller diameter pipes will experience higher stresses when placed under bending moments due to ground movement and vibration. Such higher stresses pose an increased risk of cracking.

It is Black & Veatch's opinion that similar to the unprotected bare steel mains, these mains should also be targeted for replacement under the Company's accelerated mains replacement program. Such replacements should be prioritized based on the analysis of data using all of the tools available to Columbia's management.

18. Columbia's Year-End Backlog of Leaks Pending Repair - 2007

Each distribution operator is also required by the DOT to report the number of gas leaks awaiting repairs at the end of each year (commonly known as year-end leak backlog). Leaks remaining in backlog are not classified by cause until they are repaired or eliminated. Leaks in backlog typically include leaks on both mains and services, due to corrosion, natural forces, joints leaks, material or weld failure, outside forces, and other. Typically they do not include leaks due to third party excavations damage since those leaks are usually repaired the same day.

Typically, the number of leaks pending repair at the end of a year is directly related to the amount of unprotected bare steel and unprotected coated steel pipe and cast iron pipe remaining in service, its associated level of corrosion and joint leaks, and Company resources available to repair or replace the offending sections of main.

In addition to individual leaks being worked by the Company until they are repaired, as sections of higher risk piping are replaced, the replacement will reduce the production of new leaks, and also eliminate the existing leak backlog associated with those mains and services.

Figure 21 compares Columbia leak backlog to all companies with 50 miles or more of unprotected bare steel main. In 2007, the Company reported 311 leaks in backlog.

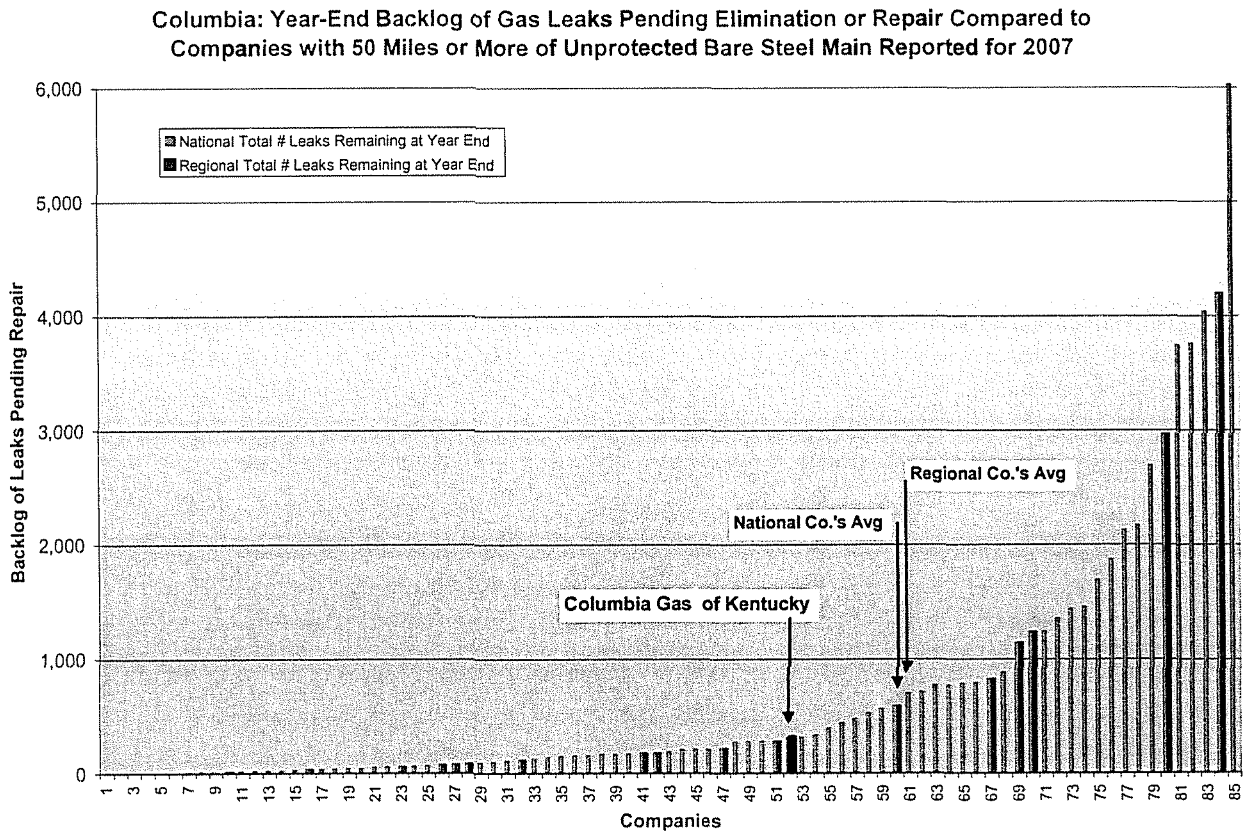


Figure 21

19. Comparison of Year-End Backlog of Gas Leaks Pending Repair and the Number of Gas Leaks Due to Corrosion on Mains and Services 1998 - 2007

The number of Columbia's gas leaks due to corrosion repaired or eliminated on both mains and services has been generally trending lower during the past ten years (Figure 22). However, we observed an overall increase in the number of corrosion leaks repaired on mains and services in 2006 and 2007 compared to the prior two years.

Figure 22 also illustrates the number of gas leaks awaiting repair at year-end (backlog), for the ten year period. From this chart one can observe that Columbia has maintained a relatively steady level of backlog from 1998 to 2006. In 2007, there was an increase of 171 (122%) leaks in backlog.

Maintaining a close watch on these two elements helps provide an indicator as to any changes in magnitude of system leaks.

The 2007 increase in both the number of corrosion leaks repaired on mains and services, as well as an increase in the number of leaks in the year-end backlog is an indication that the increase in gas leaks due to corrosion was not due to the Company applying extra efforts to reduce its leak backlog (which would include some leaks caused by corrosion). This suggests that Columbia did experience an increase in leaks due to corrosion in 2007.

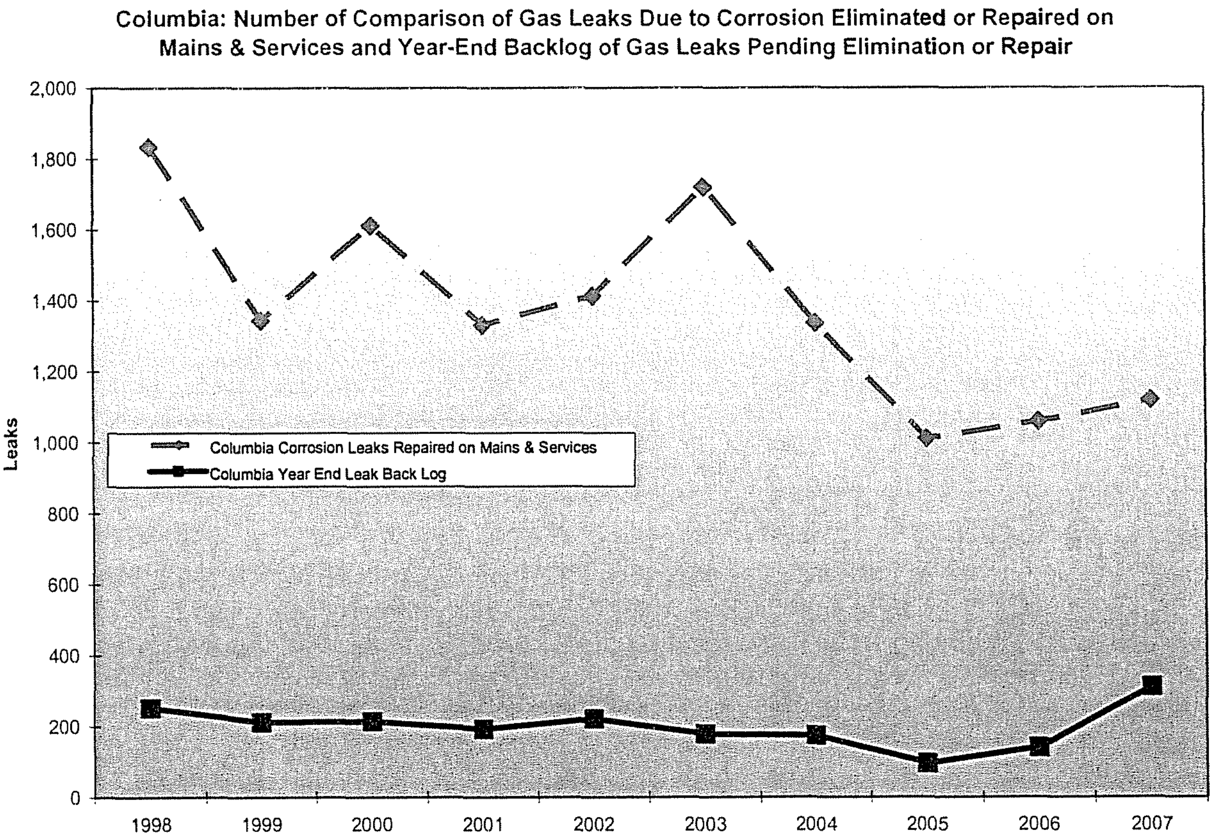


Figure 22

CONCLUSIONS

In our opinion, the issue that Columbia faces is not "if" it will need to replace its unprotected 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. Two examples are:

Scenario 1 - Status Quo or Follow Columbia's Historical Replacement Rate

In this scenario, Columbia would continue to replace mains at its ten-year average annual replacement rate. This rate represents a 52-year replacement time frame which we believe is too long a period of time. While Columbia will replace mains based on their risk priority, if it was to replace its oldest mains first, it would result in Columbia's late vintage mains installed in the 1960s being replaced when they are 91 years old.

When these main segments age to the point that they begin to experience a continuing increase in the number of gas leaks due to corrosion and a corresponding increase in corrosion leaks repaired or eliminated per mile, this situation may challenge Columbia's ability to manage the risks associated with higher levels of gas leaks and the resources required to keep up with the necessary level of leak repairs. This problem is not unique to Columbia. Other companies that have a large inventory of unprotected 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 safety and reliability risks 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 unprotected bare steel mains at an annual rate significantly greater than today. It would begin with the mains that have been identified as potentially having the highest risk conditions, as identified by Columbia's management, using all of its decision making support tools.

For example if Columbia was to determine that the shortest manageable time frame to complete the necessary main replacements is 30 years, under this scenario Columbia would strive to replace 1.75 times the amount it replaced on average from 1998 through 2007 or approximately 16 miles of unprotected bare steel main per year.

When one includes the replacement of 25 miles of Columbia's cast iron mains over the same 30 year period, it increases the number of replacement miles to approximately 17 miles per year.

Black & Veatch believes that this rate of replacement is a reasonable expectation and that it should provide a significant improvement in the safety and reliability of the Company's distribution system.

This proactive approach would provide a planned mechanism to replace Columbia's aging, high risk 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 system while avoiding numerous repairs of the piping before its eventual replacement.

However, if during its planned accelerated mains and services 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 its aging higher risk mains.

We have been advised by Columbia that it has begun to accelerate the replacement of its higher risk mains and services. We believe that this is an appropriate step towards enhancing the safety and reliability of their distribution system.

Accelerated Mains Replacement Activities in Other Utilities

It should also be noted that other companies in the same region as Columbia have also recognized the need to replace their bare steel mains. Such companies include: Duke Energy (Kentucky and Ohio utilities), Dominion East Ohio, Vectren Energy Delivery (Ohio) and Columbia Gas of Ohio. A number of other natural gas utilities have also concluded that such accelerated higher risk piping replacement programs are in the best interest of their customers and they have implemented accelerated replacement programs.

In the case of Duke Energy - Ohio, it 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 2007 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.

Duke Energy's replacement program, as testified by Mr. Hebbeler, has resulted in a significant reduction of leaks repaired from 6,223 leaks in 2002 to 4,193 leaks in 2006 when the replacement program was 48% complete. Black and Veatch would expect similar results for Columbia as its unprotected bare steel and cast iron mains replacement program is implemented.

According to Duke Energy - Kentucky's web site, the goal of its accelerated mains replacement program, approved by the Kentucky PSC in 2001 is to replace all 12" and smaller cast iron and bare steel gas mains over a 10-year period. The web site also states that "As of January 1, 2005, there are approximately 111 miles of cast iron and bare steel gas mains in our Kentucky service territory that are scheduled to be replaced. Approximately 18 miles will be replaced each year, with the expected completion date in the year 2011."

While Duke Energy is progressing under a 10-year bare steel and cast iron mains replacement program, if Columbia was to attempt to replace its higher risk mains in 10 years, it would mean that Columbia would need to increase it main replacements from its ten year average of 9.7 miles[5] per year to 52 miles per year. Based on discussions with Columbia, this level of increase would likely severely strain Columbia's manpower, equipment, materials and financial resources.

In Dominion East Ohio's recent rate case, the Public Utility Commission of Ohio (PUCO) approved accelerated mains replacement cost tracker for its mains and service replacement program. Dominion plans to replace its bare steel and cast iron mains over a 25-year period.

In both the Vectren Energy Delivery and Columbia Gas of Ohio recent rate cases, settlement agreements that include the approval of accelerated mains replacement cost trackers, have recently been submitted to the PUCO and the utilities are awaiting the final PUCO Order. Vectren plans to replace its bare steel and cast iron mains over a 20-year period. Columbia Gas of Ohio plans to replace its bare steel and cast iron mains over a 25-year period.

In addition, the American Gas Association in its December 2007 report titled "Infrastructure Cost Recovery Mechanisms" reports that utilities in 11 states have implemented infrastructure cost recovery mechanisms. It also reports that requests for approval of such mechanisms are pending in another 3 states.

[5] 1998 through 2007 average bare steel replacement rate of 9.4 miles per year plus 1998 through 2007 average cast iron replacement rate of 0.3 miles per year

Summary of Key Findings and Opinions:

1. Corrosion experts such as Peabody have documented the exponential growth of gas leaks due to corrosion 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 unprotected bare steel mains may be exposed to an acceleration of leakage incidents as its higher risk pipes age. For the period 1998 through 2007 the weighted average of Columbia's corrosion leaks on mains was 73% of all leaks on mains (excluding leaks caused by excavation).

2. In 2007, 1,426 distribution gas distribution operating companies reported to the DOT in 2007, of which 85 companies had 50 miles or more of unprotected bare steel remaining in their distribution systems. Columbia reported 493 miles of unprotected bare steel mains which ranks 24th highest out of the 85 companies. Columbia reported having no unprotected bare or coated steel mains in its transmission system.

3. Columbia's miles of unprotected bare steel main represent 19% of its total inventory of mains. Columbia had 246 corrosion leaks on mains in 2007. Columbia reports that 96% of the time these leaks occurred on its bare steel mains. Bare steel is known in the gas industry as a higher risk 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 cathodically protect such mains.

4. Based on the leak management measure, the number of gas leaks due to corrosion repaired or eliminated on mains per mile of unprotected bare and unprotected coated steel mains, Columbia's rate was lower than the weighted average rate of national and 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 2007 corrosion leak rate on mains for Columbia (0.50) was to simply rise to the level of the weighted average corrosion leak rate on mains for regional companies (not including Columbia) in 2007 (0.72), that would mean that Columbia's annual corrosion leaks would increase from 246 to 357 leaks (a 45% increase). Such potential increases 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 identifying and prioritizing its high risk mains for replacement first and accelerating the replacement of these higher risk 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.

5. For the period 1998 through 2007 the average replacement rate was 9.4 miles per year (1.9%), which if extrapolated would result in the replacement of its unprotected bare steel system in approximately 52 years. While Columbia will replace mains based on their risk priority, if for example a plan to remove the oldest mains first was implemented, at Columbia's replacement rate over the past ten years, the last pipe to be replaced would be older than 91 years.

6. In 2007, Columbia had 25 miles of cast iron main remaining in its distribution system. Cast iron mains, while less prone to corrosion leakage, are also poor performers due to its joining methods and brittleness. Cast iron sections of pipe are typically joined together with bell and spigot joints that were sealed with jute and calked lead, which leak over time. In addition, cast iron can leak at a crack in the wall of a main because of its brittle failure mode that can result in sudden and serious leakage. Approximately 80% of Columbia's cast 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. In 2007 Columbia reported having 14,137 unprotected bare steel services remaining in its distribution system. During the period 1998 through 2007 Columbia's corrosion leak rate on services, measured by the number of corrosion leaks on services per 1,000 unprotected bare and coated steel services was

consistently higher than the weighted average of regional companies. In 2007 Columbia's corrosion leak rate was 61.8 gas leaks due to corrosion per 1,000 unprotected bare and unprotected steel services, as compared to the regional corrosion leak rate of 12.5 and the national corrosion leak rate of 10.4. We believe that Columbia, as part of its accelerated mains and services replacement program, should further evaluate the current gas service corrosion leak situation and its plans for replacing these services.

8. Columbia's level of gas leaks awaiting repair at the end of 2007 increased by 171 leaks (122%), while at the same time the total number of corrosion leaks on mains and services that were repaired increased. The 2007 increase in both the number of corrosion leaks repaired on mains and services, as well as an increase in the number of leaks in the year-end backlog is an indication that the increase in corrosion leaks was not due to the Company applying extra efforts to reduce its leak backlog (which would include some leaks caused by corrosion). This suggests that Columbia did experience an increase in leaks due to corrosion in 2007.

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's 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.

Further a well planned accelerated mains replacement program would benefit the gas system and thus the gas customers. These gas system benefits would occur as the planned replacement in lieu of the emergency replacement can be dovetailed with meeting system efficiency and optimization improvements. Such improvements may include: the removal of redundant mains (2 mains on a street), upgrading of pressure ratings as needed by the gas system, back-feeding the system by looping mains and connecting nodes where appropriate, upsizing mains to avoid the need for reinforcement or reliability main installations, replacing or relocating mains to accommodate proposed city and state construction, replacement of shallow or excessively deep mains, as well as other system improvements.

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 Kentucky Public Service Commission support and approve the implementation of Columbia's accelerated mains and services replacement program.

APPENDIX A

List of 85 Companies Meeting the Selection Criteria within the National Sample

1 Alabama Gas Corporation
2 Aquila Networks - KS
3 Aquila Networks - NE
4 Arkansas Western Gas Co
5 Atlanta Gas Light Co
6 Atmos Energy - West Texas Division
7 Atmos Energy Corporation - KY/Mid States Division - KY
8 Atmos Energy Corporation - KY/Mid States Division - TN
9 Atmos Energy Corporation, Colorado - Kansas Division
10 Atmos Energy Corporation, Mid-Tex Division
11 Baltimore Gas & Electric Co
12 Bay State Gas Co
13 Boston Gas Co
14 Cape Cod Gas Co (Div of Colonial Gas Co)
15 Centerpoint Energy Resources Corp., DBA Centerpoint Energy Minnesota Gas
16 Central Florida Gas Corp (Winter Haven)
17 Central Hudson Gas & Electric Corp
18 Chartiers Natural Gas Co Inc
19 Clearwater Gas System
20 Columbia Gas of Kentucky Inc
21 Columbia Gas of Maryland Inc
22 Columbia Gas of Ohio Inc
23 Columbia Gas of Pennsylvania
24 Columbia Gas of Virginia Inc
25 Consolidated Edison Co of New York
26 Consumers Energy Co
27 Consumers Gas Utility Co
28 Corning Natural Gas Corp
29 Delta Natural Gas Co Inc
30 Dominion East Ohio
31 Dominion Hope
32 Dominion Peoples
33 Duke Energy Ohio
34 Equitable Resources (A.K.A Equitable Gas Co)
35 Florida City Gas - Consolidated
36 Florida Public Utilities Co
37 Indiana Gas Co Inc
38 Kansas Gas Service - KS
39 Kansas Gas Service - OK
40 Keyspan Energy Delivery - Long Island
41 Keyspan Energy Delivery - NY City
42 Knox Energy Cooperative Association, Inc. C/O Utility Pipeline, Ltd.
43 Lancaster Municipal Gas Co, City of
44 Louisville Gas & Electric Co
45 Michigan Consolidated Gas Co (MICHCON)
46 Midamerican Energy Company
47 Midwest Energy Inc

48 Mountaineer Gas Co
49 National Fuel Gas Distribution Corp
50 National Fuel Gas Distribution Corp - New York
51 National Gas & Oil Corp
52 New England Gas Company
53 New Jersey Natural Gas Co
54 New York State Electric & Gas Corp
55 Niagara Mohawk Power Corp - NY
56 Niagara Mohawk Power Corp - RI
57 Northern Illinois Gas Co
58 Northern Indiana Public Service Co
59 NSTAR Gas Company
60 Oklahoma Natural Gas Co
61 Orange & Rockland Utility Inc
62 Pacific Gas & Electric Co
63 PECO Energy Co
64 Pensacola, Energy Services Of
65 Peoples Gas System Inc
66 PPL Gas Utilities Corp
67 Public Service Co of Colorado
68 Public Service Electric & Gas Co
69 Puget Sound Energy
70 Reliant Energy Arkla, Div of Reliant Energy Resources
71 Rochester Gas & Electric Corp
72 SEMCO Energy Gas Company
73 South Jersey Gas Co
74 Southern California Gas Co
75 Southern Connecticut Gas Co
76 Southern Indiana Gas & Electric Co
77 T W Phillips Gas & Oil Co
78 Texas Gas Service Company
79 The Gas Company
80 U G I Corp
81 UGI Penn Natural Gas
82 Vectren Energy Delivery of Ohio
83 Washington Gas Light Co
84 West Texas Gas Inc
85 Yankee Gas Services Co

APPENDIX B

List of 19 Companies Meeting the Selection Criteria within the Regional Sample

1 Atmos Energy Corporation - KY/Mid States Division - KY
2 Atmos Energy Corporation - KY/Mid States Division - TN
3 Columbia Gas of Kentucky Inc
4 Columbia Gas of Ohio Inc
5 Columbia Gas of Virginia Inc
6 Consumers Gas Utility Co
7 Delta Natural Gas Co Inc
8 Dominion East Ohio
9 Dominion Hope
10 Duke Energy Ohio
11 Indiana Gas Co Inc
12 Lancaster Municipal Gas Co, City of
13 Louisville Gas & Electric Co
14 Mountaineer Gas Co
15 National Gas & Oil Corp
16 Northern Illinois Gas Co
17 Northern Indiana Public Service Co
18 Southern Indiana Gas & Electric Co
19 Vectren Energy Delivery of Ohio

CONTACT INFORMATION:

Black & Veatch Corporation
898 Veterans Memorial Highway, Suite 430
Hauppauge, New York 11788

Web site: www.bv.com

BLACK & VEATCH
Building a **world** of difference®.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF JUDY M. COOPER ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF JUDY M. COOPER

Q: Please state your name and business address.

A: My name is Judy M. Cooper and my business address is Columbia Gas of Kentucky, Inc., 2001 Mercer Road, Lexington, KY 40511.

Q: What is your current position and responsibilities?

A: I am the Director of Regulatory Policy for Columbia Gas of Kentucky, Inc. I am responsible for the management of Columbia's regulatory affairs, tariffs and filings with the Commission, including quarterly Gas Cost Adjustments. I am also responsible for Columbia's local customer service functions

Q: What is your educational background?

A. I am a graduate of the University of Kentucky where I received a Bachelor of Science Degree in Accounting in 1982. I also received a Masters in Business Administration from Xavier University in 1985.

Q: Please describe your employment history?

A: I was employed by the Kentucky Public Service Commission ("Commission") as an auditor in 1982. Subsequently, I was served as a rate analyst, Energy Policy Advisor, Branch Manager of Electric and Gas Rate Design, and Director of Rates, Tariffs and Financial Analysis at the Commission. In July of 1998 I joined Columbia as Manager of Regulatory Services. My job title has since been revised to that of Director, Regulatory Policy.

Q. Have you previously testified before the Kentucky Public Service Commission or any other Kentucky regulatory commissions?

A: Yes, I have testified before the Kentucky Public Service Commission in two cases for Columbia. Case No. 2002-00117, "The Filing by Columbia Gas of Kentucky, Inc. to Require that Marketers in the Small Volume Gas Transportation Program be Required to Accept a Mandatory Assignment of Capacity" and Case No. 2007-00008, "In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc."

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

A: The purpose of my testimony is to sponsor the proposed modifications to Columbia's tariff pages 1, 5, 6, 7, 7a, 11, 12, 14, 15, 19, 20, 21, 22, 31, 38, 39, 40, 41, 42, 43, 44, 45, 48, 50b, 51a, 51d, 51e, 51f, 51g, 58, 59, 67, 70, 74, 75, 76, 77, 80a and 82 set forth in Schedule L according to 807 KAR 5:001 Section 10(1)(b)(7) and 807 KAR 5:001 Section 10(1)(b)(8). I will also address proposals designed to address the cost recovery issues associated with the accelerated replacement of bare steel and cast iron pipe. In addition, I will address new adjustment clauses and riders for pension and OPEB expense, Energy Efficiency/Conservation Program cost recovery and gas cost uncollectibles.

Tariff Modifications

Q: Please provide a general description of the proposed tariff modifications contained in Schedule L of Columbia's application.

A: The rate changes shown on tariff pages 5 through 41 are base rate changes. These changes are supported by the revenue requirement contained in the testimony of Columbia witness Racher and the rate design contained in the testimony of Columbia witness Balmert. Other revisions are proposed to update certain special charges, add a penalty for late payment to the residential customer class, update the terms of budget billing, and installation of remote meter reading devices, and other housekeeping revisions to the Tariff. I will also be supporting the tariff modifications for the proposed Accelerated Main Replacement Program ("AMRP") Rider, Pension and OPEB Mechanism ("Rider POM"), and Gas Cost Uncollectible Rider. Columbia witness Seelye will address the Energy Efficiency and Conservation Rider. Columbia witness Konold will provide details of the Rider POM. Columbia witness Balmert will describe the Gas Cost Uncollectible Rider and Columbia witness Evans will address two new service offerings.

Q: Is Columbia proposing to change any of its miscellaneous non-recurring charges?

A: Yes. Columbia proposes to increase its fee for reconnection of service when a customer has qualified for and requested service be reconnected after service has been disconnected for nonpayment of bills or for violation of Columbia's Rules and Regulations. Columbia has experienced an increase in costs for performing certain services and handling certain transactions in providing customer service that have historically been identified in the rate-making process as costs that should be borne by the specific customers using the service or causing the cost to be incurred, rather than being allocated among all ratepayers. In particular, Columbia identified the reconnect fee set forth on Tariff Sheet 70 as being currently well below associated costs and billed a significant number of times. The reconnect fee was increased in Columbia's last rate case, but is still well below the cost of performing the service. The intent of special charges is to assign the cost that the company incurs to the cost-causer. The revision being proposed is intended to more correctly align the amount of the charge with the actual cost, thus assigning the appropriate costs to the appropriate customers. This is a ratemaking principle to which the Commission has historically adhered.

Q: What is Columbia's proposal for the fee for reconnection of service?

A: Columbia proposes to increase the fee for reconnection of service, except where service was discontinued at the request of the customer, from $25 to $60. This revision is set forth on Sheet 70 of Columbia's tariff. Attachment JMC-1 shows Columbia's cost to provide a service reconnection. The reconnect fee is based on the full labor and vehicle costs of a one-hour reconnection order which is $64.20.

Q.: When was Columbia's fee for reconnection of service last revised?

A: The fee for reconnection of service due to disconnection for non-payment of bills or violations of Columbia's rules and regulations was established at the current $25 in 2007. The previous amount of $15 had been established in 1983.

Q: What is the impact of Columbia's proposed change in reconnect fees to its annual revenues for these miscellaneous services?

A: Attachment JMC–2 shows the comparison of Columbia's reconnect charge at present and proposed rates using the actual number of occurrences during 2008. Anticipating that the increased charges will impact customer behavior and reduce the number of future occurrences, I applied a behavioral factor of 75% to the number of occurrences in order to determine the total revenues to be generated by the proposed reconnect charge.

Q: Please explain the basis for the behavioral factor adjustment of 75%.

A: Columbia previously utilized a 75% behavioral adjustment factor in Case No. 2007-00008. At that time, Columbia proposed the behavioral adjustment because it believed it was highly unlikely that Columbia would experience a level of reconnect fees consistent with test year actual numbers when a higher fee was established. Columbia proposed to increase the reconnect fee from the then authorized $15 to $55. Because a drop in occurrences was expected based on the proposed increase, Columbia estimated that it would only realize 75% of the additional revenue that it would have otherwise received if the drop in occurrences were not to occur. The behavioral adjustment is proposed for the same reasons in this case. The actual number of occurrences has decreased by 20% from Case No. 2007-00008. The decrease was not as great as expected in Columbia's application because the authorized increase was not as great as proposed. The reconnect fee increased from $15 to $25 rather than the proposed $55. The 75% behavior factor is appropriate based upon the proposed higher reconnect fee of $60.

Q: Does Columbia propose any revision to its fee to reconnect service that was discontinued at the request of the customer?

A: Yes. This charge is applicable to a customer that requests reconnection of service at the same premises within eight months of having requested discontinuance of service at the same location. The intent of this charge is to properly assign costs to those customers who engage in seasonal disconnection of gas service and thereby eliminate an unintended incentive to do so by virtue of a reconnect fee that is less than the aggregate minimum monthly charge. The current fees of $74.40 for residential customers and $191.68 for other customers were established in 2007 and set forth on Sheet 70 of Columbia's tariff as Columbia's minimum monthly charge for each customer class times eight. Columbia proposes to apply the same logic in this application. The resulting reconnect fees are proposed to be $143.36 ($17.92*8) for residential customers and $226.24 ($28.28*8) for commercial and industrial customers in the first year. In the second year, the fee would be $212.24 ($26.52*8) for residential customers and $226.24 (28.28*8) for commercial and industrial customers.

Q: Does Columbia propose any other changes to the General Terms, Conditions, Rules and Regulations of its tariff?

A: Yes. Columbia proposes modifications in three sections of the General Terms, Conditions, Rules and Regulations of its tariff. First, on Sheet 67, Section 17 - Meter Testing and Measurement of Natural Gas; second, on Sheet 74, Section 25 - Late Payment Penalty; and, third, on Sheets 75 - 77, Section 28 - Budget Plan.

Q: Please explain the change on Sheet 67, Section 17 - Meter Testing and Measurement of Natural Gas.

A: Columbia proposes to add a statement that would allow it to waive the cost of the remote meter reading device at Columbia's discretion. Columbia contemplates it would waive the fee when it would be cost-efficient and to the Company's advantage to install a remote meter reading device, such as when Columbia has been unable to routinely obtain an actual meter reading.

Q: Please explain the change on Sheet 74, Section 25 - Late Payment Penalty.

A: The proposed change would remove the current exemption from the Late Payment Penalty for residential customers. This proposal is explained in the testimony of Columbia witness Balmert.

Q: Please explain the change on Sheets 75-77, Section 28 - Budget Plan.

A: The current language on Sheets 75-77 dates back to 1993. Columbia proposes to amend the current language to consolidate the text and remove the outdated terms "Twelve Month Equal Payment Plan" and "Off Season Equal Payment Plan." The amended language would remove the limitation of the Budget Plan to a customer that uses gas as the primary source of space heating and allow all residential and small commercial customers to participate in the Budget Plan. The Budget Plan is a wonderful tool to help customers manage the seasonal peaks that would otherwise hit their pocketbooks during the heating season. Columbia encourages customers to participate in the Budget Plan and proposes to automatically enroll new customers at the time service is initiated unless the customer opts not to participate.

Q: Does Columbia permit a customer with an outstanding account balance to enroll in its Budget Plan?

A: Yes, a customer is not required to have a zero account balance to enroll in the Budget Plan. In fact, Columbia encourages customers to join the Budget Plan as a way to help customers manage their bills.

Q: Does Columbia propose any changes in the actual operation of the Budget Plan from the current operation?

A: Columbia does not propose any change in the calculation of the monthly budgeted amount. However, Columbia does propose to change the start month of the budget plan from August to May, and the settlement month from July to May. The Budget Plan is currently promoted to customers in Columbia's August billing cycle. In the future Columbia proposes to promote the budget at the end of the heating season when customers have a greater awareness and better realize the advantage of the Budget Plan to levelize bills. It is hoped that a promotion near the end of the heating season, as opposed to a promotion during the summer when it is still warm, will be of greater interest to customers and participation will increase.

Q: What are the "housekeeping" revisions that Columbia proposes to its tariff?

A: Columbia proposes to transfer Sheet 7a in its entirety to Sheet 7, which is currently blank, and eliminate Sheet 7a. Columbia also proposes to correct an omission to the Weather Normalization Adjustment Clause. Finally, Columbia proposes to consolidate the applicable Adjustments and Riders to each Rate Schedule under a heading "<u>Adjustments and Riders</u>" within each rate schedule in order to make the tariff more user-friendly.

Q: Please explain the change on Sheet 51a, Weather Normalization Adjustment Clause.

A: The change on Sheet 51a, Weather Normalization Adjustment Clause is to correct an inadvertent omission resulting from the consolidation of all elements of transportation service in Case No. 2007-00008. The change in title and applicability reflects the insertion of Rate Schedule GDS. Rate Schedule GDS was incorporated into Rate Schedule DS, Tariff Sheet No. 38, in Case No. 2007-00008 thus dissolving the link to Rate Schedule GS that provided the applicability of the Weather Normalization Adjustment Clause. Inserting Rate Schedule GDS as proposed corrects this inadvertent omission. There is no change in the operation of the clause or its impact on any customer.

AMRP Cost Recovery Mechanism

Q: What is the purpose of Columbia's proposed AMRP Rider?

A: The purpose of the AMRP Rider is to establish a mechanism to recover the cost of the Accelerated Main Replacement Program ("AMRP"). This mechanism is identified in Columbia's proposed tariffs as Rider AMRP - Accelerated Main Replacement Program Rider (Sheet No. 58). As described in the testimony of Columbia witnesses Vitale and Mueller, the AMRP is in the public interest, and the financial impact of the program on Columbia over the next 30 years is significant, as described in the testimony of Columbia witness Mueller. The mechanism will recognize cost changes and rate base changes directly related to Columbia's investment in the AMRP and establish a charge, or credit, to customers for the net change in revenue requirement attributable to the AMRP.

Q: Have similar mechanisms been approved for other distribution utilities in Kentucky?

A: Yes. The Commission authorized Duke Energy Kentucky, Inc. (formerly The Union Light, Heat & Power Company) to implement a similar mechanism in Case Nos. 2001-00092 and 2005-00042. Columbia has modeled its mechanism on that approved for Duke Energy - Kentucky. Columbia's program spans 30 years as compared to Duke's 10-year program and includes the replacement of approximately 525 miles of pipe and customer service lines. The expected annual investment under the program is approximately $7 million per year.

Q: Please describe how Columbia's proposed AMRP Rider will work.

A: The AMRP Rider is a tracking mechanism that will allow Columbia to make annual rate adjustments over a 30-year period, in order to recognize cost changes and rate base changes directly related to the AMRP.

Q: What are the filing requirements associated with the proposed revenue adjustment for Rider AMRP?

A: Columbia proposes to submit its annual adjustment of Rider AMRP on or about April 1 each year, to be effective with meter readings on and after its June billing cycle of the same year. The adjustment would be calculated to reflect actual activity for the prior calendar year and would be subject to Commission review.

Q: Please describe the calculation of the annual adjustment for the AMRP.

A: The computation is a calculation of the return on, and return of, the net change in plant investment attributable to the program converted to an annual revenue requirement amount using traditional ratemaking theory and financial data to be approved in this proceeding. The annual adjustment will be calculated by determining the changes in return on rate base and recovery of expense. The first part of the annual adjustment calculation will determine the change in return on rate base associated with AMRP related investments. The authorized rate of return, adjusted for income taxes as determined in this case, will be applied to the new cumulative AMRP net rate base to calculate the allowed return on AMRP related rate base. The second part of the annual adjustment calculation will determine the change in operating expenses associated with AMRP related investments. This change is a comparison of Depreciation Expense for the various categories of mains, services, meter relocations and customer service lines and Maintenance Expense – Account 887. The net change in return on rate base and recovery of expense associated with the AMRP will be reflected in the AMRP Rider.

Q: How are the effects of the AMRP on Columbia's operating and maintenance costs treated in the proposed mechanism?

A: It is expected that, over time, the AMRP will result in a reduction in Columbia's operation and maintenance expense to repair and maintain the cast iron, bare steel and other mains and services as these facilities are replaced. The annual revenue requirement mechanism proposes to immediately pass on to customers the net reduction in maintenance costs which result from the program by comparing the actual amount in Account

887-Maintenance of Mains for the prior year to the amount allowed in Account 887-Maintenance of Mains in the Commission's Order in this case.

Q: How will depreciation expense be treated under Rider AMRP?

A: The annual revenue requirement mechanism will reflect depreciation expense on the new AMRP eligible plant that Columbia installs to replace the existing cast iron and bare steel pipe, and provide customers the benefit of the reduction in depreciation expense attributable to the mains and services that are removed from service. Depreciation expense on the AMRP related plant will be calculated at the depreciation rates approved in this case.

Q: Does the tracking mechanism in Rider AMRP mean that Columbia will adjust its revenue requirement to recover its expected investment of $7 Million per year in each year?

A: No. The cost of the program is not recovered in each year, or even over 30 years. Here is an example of the calculation provided in Rider AMRP.

Assume the previous year's investment under the AMRP is $7 Million. This amount would be reduced by the additional reserve for depreciation (assume this is $151,200 annually) and deferred income taxes related to the $7 Million investment (assume this amount is $1,241,083). Subtracting $151,200 and $1,241,083 from $7,000,000 yields the sum $5,607,717 which we term the "net rate base for AMRP purposes." The rate of return authorized in this case, adjusted for taxes, is applied to the net rate base to calculate the return on AMRP related investment. In our example, that means $5,607,717 times 13.06% (Columbia's proposed return adjusted for taxes) or $732,211. The change in operating expenses associated with the AMRP is the next step. For this example, assume the change in depreciation expense associated with the AMRP plant is $151,200 and assume that Account 887 – Maintenance Expense is reduced by $25,000 in the calendar year. These changes are summed with the return component to determine the change in Columbia's revenue requirement. In our example, $732,211 + $151,200 - $25,000 = $858,411. Thus, the Rider AMRP annual adjustment would be $858,411.

Q: Are there any financial benefits of the AMRP that are not quantified in the proposed rate mechanism?

A: Yes. Any reduction in line losses, previously attributable to the cast iron and bare steel pipe being replaced, will automatically accrue to customers through Columbia's Gas Cost Adjustment mechanism.

Q: When does Columbia propose to file its first AMRP Rider filing?

A: Columbia proposes to make its first filing on April 1, 2010. This filing would cover AMRP investments made since the end of the test year in this case, that is, since December 31, 2008. Subsequent filings would be made on or about April 1 of each year, and would cover AMRP investments made during the prior calendar year.

Q: How will main replacement expenditures be reflected in future base rate proceedings?

A: As indicated in Columbia witness Miller's testimony, the ability to recover the depreciation and carrying costs related to the capital investment, less operating expense reductions, diminishes Columbia's need to file frequent rate case applications. However, should a general rate case be filed during the AMRP period, the program investment and reduced operating expense should be included in base rates and the Rider AMRP reset to zero.

Q: Have you estimated the annual revenue requirement attributable to the AMRP for each of the next 30 years?

A: Yes. Attachment JMC-3 reflects an estimated revenue requirement attributable to the AMRP for each of the next 30 years. The numbers are for illustration only as no amounts are included for the savings in Account 887-Maintenance of Mains expense and the per customer impact is calculated based on a straight per number of customers basis. Columbia proposes to actually allocate the AMRP related revenue requirement among customer classes based on the overall base revenue distribution approved in this case. The revenue adjustment allocated to each class would be converted to a per customer charge based on the number of customers in each class. No revenue adjustments would be allocated to customers served under Rate Schedule MLDS or the Flex Provision of Rate Schedule DS. This is consistent with the rate design testimony of Columbia witness Balmert and Columbia's effort to align fixed costs with fixed charge recovery.

Other Adjustments and Riders

Q: Please describe the revisions to Tariff Sheet No 50b.

A: Tariff Sheet 50b sets forth Columbia's proposed Gas Cost Uncollectible Charge Adjustment Clause. A detailed explanation of the Gas Cost Uncollectible Charge and adjustment mechanism is provided in the testimony of Columbia witness Balmert.

Q: Please describe the new tariffs Sheet Nos. 51d, 51e, 51f, and 51g.

A: Tariff Sheets 51d through 51g set forth Columbia's proposed demand-side management cost recovery mechanism for approved demand-side management programs and is entitled Energy Efficiency and Conservation Program Rider. The initial Energy Efficiency/Conservation programs that Columbia proposes to offer, the estimated costs and a detailed explanation of the cost recovery mechanism are provided in the testimony of Columbia witness Seelye.

Q: What are the filing requirements associated with the proposed Energy Efficiency and Conservation Program Rider?

A: Columbia proposes to submit its annual adjustment of the Energy Efficiency/Conservation Program Recovery Component pursuant to the Energy Efficiency and Conservation Program Rider on or about January 1 each year, such that 30 days notice is provided for the rate to become effective with bills rendered on and after the date of Columbia's February Unit 1 bills. Energy Efficiency/Conservation programs are planned and budgeted on a twelve-month basis beginning November 1 and ending October 31. Program modifications that would change the Energy Efficiency/Conservation Program Cost Recovery component shall be made at least two months prior to the end of the program year.

Q: Please describe the revisions to Tariff Sheet No. 59.

A: Tariff Sheet No. 59 is Columbia's proposed cost recovery mechanism to track pension and OPEB expense and is entitled Rider POM. A detailed explanation of the mechanism is provided in the testimony of Columbia witness Konold.

New Service Offerings

Q: Is Columbia proposing any new service offerings?

A: Yes. Columbia proposes to offer two new services to its customers. The proposed service offerings are described in the testimony of Columbia witness Evans. They are Rate Schedule PPS – Price Protection Service, set forth on Tariff Sheet Nos. 19 – 21; and Rate Schedule NSS – Negotiated Sales Service, set forth on Tariff Sheet Nos. 42 – 45.

Q: Does Columbia intend to continue to offer Rate Schedule AFDS currently set forth on Tariff Sheet Nos. 42-45?

A: No. Columbia does not currently serve any customers under Rate Schedule AFDS and has not had any customers or customers interested in the service for a number of years. Columbia proposes to replace Tariff Sheet Nos. 42-45 with the new service offering which is termed Rate Schedule PPS.

Q: How do the proposed new service offerings impact Columbia's Gas Cost Adjustment Clause set forth on Tariff Sheet No. 48 ?

A: The future calculation of the Actual Cost Adjustment (ACA) of Columbia's Gas Cost Adjustment Clause set forth on Tariff Sheet No. 48 will include the credits derived from the service provided under Rate Schedule PPS and Rate Schedule NSS. This calculation is further explained in the testimony of Columbia witness Evans. Columbia's proposed Tariff Sheet No. 48 reflects a revision to include the credits in the ACA.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

Columbia Gas of Kentucky, Inc.
Cost Analysis
Special Charges

Reconnect Fee (Other than at Customer request)

CKY Service Technician - Base Labor (1 Hour)	$26.14
Overheads and Vehicle Charges	$38.06
Total Cost	$64.20

Attachment JMC-2

Columbia Gas of Kentucky, Inc.
Miscellaneous Revenue Fees

Ln. No.	Item	Current Fee (1) ($)	Proposed Fee (2) ($)	Increase (3)=(2-1) ($)	Annual No. Occurances (4)	Behavioral Factor (5)	Revenue Increase (6)=(3*4*5)
1	Reconnect Fee - Increase	$25.00	$60.00	$35.00	5,556	75%	$145,845.00
2	Total Revenue Increase						$145,845.00

Columbia Gas of Kentucky, Inc.
Impact of the Accelerated Main Replacement Program on Customers

Ln. No.	Year	2009 ($)	2010 ($)	2011 ($)	2012 ($)	2013 ($)	2014 ($)	2015 ($)	2016 ($)	2017 ($)	2018 ($)
1	Cumulative Spend	7,000,000	14,000,000	21,000,000	28,000,000	35,000,000	42,000,000	49,000,000	56,000,000	63,000,000	70,000,000
2	Reserve for Depreciation	151,200	453,600	907,200	1,512,000	2,268,000	3,175,200	4,233,600	5,443,200	6,804,000	8,316,000
3	Deferred income taxes	1,241,083	1,401,910	1,714,335	2,125,917	2,625,816	3,203,645	3,854,218	4,580,898	5,382,012	6,247,566
4	Net rate base (Ln. 1 less Lns. 2 & 3)	5,607,717	12,144,491	18,378,465	24,362,083	30,106,184	35,621,155	40,912,182	45,975,902	50,813,988	55,436,434
5	Depreciation - Annual @ 2.16% (Ln. 1 * 2.16%)	151,200	302,400	453,600	604,800	756,000	907,200	1,058,400	1,209,600	1,360,800	1,512,000
6	Return @ pretax rate of return (Ln. 4 * ROR below)	732,211	1,585,730	2,399,713	3,181,006	3,931,025	4,651,125	5,341,985	6,003,165	6,634,884	7,238,446
7	Property Taxes, uncollectibles & PSC Fees	-	-	-	-	-	-	-	-	-	-
8	Savings - Reductions in Account 887.	-	-	-	-	-	-	-	-	-	-
9	Annual Costs	883,411	1,888,130	2,853,313	3,785,806	4,687,025	5,558,325	6,400,385	7,212,765	7,995,684	8,750,446
10	Customers @ 12/31/08	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708
11	Annual Customer costs (Ln. 8/Ln. 9)	6.46	13.81	20.87	27.69	34.28	40.66	46.82	52.76	58.49	64.01
12	Monthly Customer costs	0.54	1.15	1.74	2.31	2.86	3.39	3.9	4.4	4.87	5.33

Columbia Gas of Kentucky, Inc.
Impact of the Accelerated Main Replacement Program on Customers

Ln. No.	Year	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)	2026 ($)	2027 ($)	2028 ($)
1	Cumulative Spend	77,000,000	84,000,000	91,000,000	98,000,000	105,000,000	112,000,000	119,000,000	126,000,000	133,000,000	140,000,000
2	Reserve for Depreciation	9,979,200	11,793,600	13,759,200	15,876,000	18,144,000	20,563,200	23,133,600	25,855,200	28,728,000	31,752,000
3	Deferred income taxes	7,175,680	8,166,573	9,220,028	10,336,260	11,515,054	12,712,436	13,847,709	14,965,310	16,145,594	17,388,535
4	Net rate base (Ln. 1 less Lns. 2 & 3)	59,845,120	64,039,827	68,020,772	71,787,740	75,340,946	78,724,364	82,018,691	85,179,490	88,126,406	90,859,465
5	Depreciation - Annual @ 2.16% (Ln. 1 * 2.16%)	1,663,200	1,814,400	1,965,600	2,116,800	2,268,000	2,419,200	2,570,400	2,721,600	2,872,800	3,024,000
6	Return @ pretax rate of return (Ln. 4 * ROR below)	7,814,097	8,361,808	8,881,608	9,373,469	9,837,418	10,279,198	10,709,345	11,122,056	11,506,841	11,863,702
7	Property Taxes, uncollectibles & PSC Fees	-	-	-	-	-	-	-	-	-	-
8	Savings - Reductions in Account 887.	-	-	-	-	-	-	-	-	-	-
9	Annual Costs	9,477,297	10,176,208	10,847,208	11,490,269	12,105,418	12,698,398	13,279,745	13,843,656	14,379,641	14,887,702
10	Customers @ 12/31/08	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708
11	Annual Customer costs (Ln. 8/Ln. 9)	69.33	74.44	79.35	84.05	88.55	92.89	97.14	101.26	105.19	108.9
12	Monthly Customer costs	5.78	6.2	6.61	7	7.38	7.74	8.1	8.44	8.77	9.08

Columbia Gas of Kentucky, Inc.
Impact of the Accelerated Main Replacement Program on Customers

Ln. No.	Year	2029 ($)	2030 ($)	2031 ($)	2032 ($)	2033 ($)	2034 ($)	2035 ($)	2036 ($)	2037 ($)	2038 ($)
1	Cumulative Spend	147,000,000	154,000,000	161,000,000	168,000,000	175,000,000	182,000,000	189,000,000	196,000,000	203,000,000	210,000,000
2	Reserve for Depreciation	34,927,200	38,253,600	41,731,200	45,360,000	49,140,000	53,071,200	57,153,600	61,387,200	65,772,000	70,308,000
3	Deferred income taxes	18,694,159	20,062,439	21,432,653	22,744,050	23,996,630	25,190,393	26,325,339	27,401,469	28,418,782	29,377,278
4	Net rate base (Ln. 1 less Lns. 2 & 3)	93,378,641	95,683,961	97,836,147	99,895,950	101,863,370	103,738,407	105,521,061	107,211,331	108,809,218	110,314,722
5	Depreciation - Annual @ 2.16% (Ln. 1 * 2.16%)	3,175,200	3,326,400	3,477,600	3,628,800	3,780,000	3,931,200	4,082,400	4,233,600	4,384,800	4,536,000
6	Return @ pretax rate of return (Ln. 4 * ROR below)	12,192,636	12,493,646	12,774,661	13,043,614	13,300,504	13,545,331	13,778,096	13,998,798	14,207,437	14,404,014
7	Property Taxes, uncollectibles & PSC Fees	-	-	-	-	-	-	-	-	-	-
8	Savings - Reductions in Account 887.	-	-	-	-	-	-	-	-	-	-
9	Annual Costs	15,367,836	15,820,046	16,252,261	16,672,414	17,080,504	17,476,531	17,860,496	18,232,398	18,592,237	18,940,014
10	Customers @ 12/31/08	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708	136,708
11	Annual Customer costs (Ln. 8/Ln. 9)	112.41	115.72	118.88	121.96	124.94	127.84	130.65	133.37	136	138.54
12	Monthly Customer costs	9.37	9.64	9.91	10.16	10.41	10.65	10.89	11.11	11.33	11.55

Ln. No.		Ratio	Cost	Weighted Cost	Pre-Tax @ Effect tax of 38.90%
13	Capital Structure				
14	Short term Debt	5.425%	3.24%	0.18%	0.18%
15	Long term Debt	42.559%	5.76%	2.45%	2.45%
16	Equity	52.016%	12.25%	6.37%	10.43%
17	Total	100.00%		9.00%	13.06%

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A: Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

I. INTRODUCTION AND QUALIFICATIONS

Q: Please state you name and business address.

A: My name is William Steven Seelye, and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

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

A: I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q: On whose behalf are you testify in this proceeding?

A: I am testifying for Columbia Gas of Kentucky, Inc. ("Columbia Gas" or "Company"), a local distribution company which provides natural gas sales and transportation services in Kentucky.

Q: Please describe your educational and professional background.

A: I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed cost of service and rate studies for over 130 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. A more detailed description of my qualifications is included in Attachment Seelye-1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions including before the Kentucky Public Service Commission ("Commission"). A listing of my testimony in other proceedings is included in Attachment Seelye-1.

Q: Please describe your experience with demand side management ("DSM") programs and cost recovery mechanisms.

A: In Kentucky, I have assisted the following utilities with the development of DSM cost recovery mechanisms: Louisville Gas and Electric Company, Kentucky Utilities, and Delta Natural Gas Company. I have also developed a DSM cost recovery mechanism for Nova Scotia Power Company. I have assisted numerous utilities in the economic evaluation of their DSM, energy efficiency, and demand-response programs and have worked with utilities in maximizing the benefit derived from their existing demand side management programs. I have also developed time-of-use, interruptible, real-time pricing, co-generation, and other rates designed to encourage customers to modify their demand and usage patterns.

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

A: The purpose of my testimony is to describe Columbia Gas's proposed DSM cost recovery mechanism and to describe a set of DSM programs that the Company is proposing during the first year of implementation of the DSM cost recovery mechanism.

Q: Please provide an overview of Columbia Gas's proposed DSM cost recovery mechanism?

A: Columbia Gas's proposed DSM cost recovery mechanism, which would be applicable to residential sales and CHOICE customers and commercial sales and CHOICE customers, is designed to provide for the recovery of DSM program costs, to provide for the recovery of net revenues from lost sales due to the implementation of DSM programs, and to provide a small incentive for Columbia Gas to implement DSM programs. The proposed tariff sheets describing the DSM cost recovery mechanism, titled "Energy Efficiency and Conservation Rider ," are included as Sheet Nos. 51d through 51g of Columbia Gas' proposed tariff included in Requirement 1-7 of the Application in this proceeding.

Columbia Gas' proposed DSM cost recovery mechanism will provide dollar-for-dollar recovery of costs incurred by the Company to implement and operate DSM programs that have been approved by the Commission. The implementation of DSM programs will by design result in a reduction in sales to customers. Columbia Gas' proposed DSM cost recovery mechanism will provide for the recovery of revenues from lost sales due to the implementation of DSM programs. It is important for utilities implementing DSM programs to recover revenues from lost sales. Without the ability to recover lost revenues from the implementation of DSM programs, utilities would be penalized for their efforts in pursuing these alternatives.

Columbia Gas' proposed DSM cost recovery mechanism will provide a small incentive designed to encourage the Company to develop and implement DSM programs. Columbia Gas' proposed DSM cost recovery mechanism will include a reconciliation adjustment to ensure that there will not be any over- or under-recovery of either DSM program costs or revenues from lost sales under the mechanism.

Columbia Gas' proposed DSM cost recovery mechanism will therefore consist of the following four components: (1) an Energy Efficiency/Conservation Program Cost Recovery ("EECPCR") component that provides for the recovery of DSM program costs; (2) a EECP Revenue from Lost Sales ("EECPLS") component that provides for the recovery of revenues from lost sales; (3) an EECP Incentive ("EECPI") component that is designed to encourage Columbia Gas to develop and implement DSM programs; and, (4) a EECP Balance Adjustment ("EECPBA") that reconciles for any over- or under-recovery of program costs, revenues from lost sales, and incentives.

Q: Is Columbia Gas' proposed Energy Efficiency/Conservation Program Rider consistent with the DSM mechanism described in KRS 278.285?

A: Yes. Counsel advises me that utilities in Kentucky can propose a DSM cost recovery mechanism pursuant to KRS 278.285. Subsection 2 of KRS 278.285, states as follows:

> A proposed demand-side management mechanism including:
> (a) Recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs;
> (b) Obtain incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs; or
> (c) Both of the actions specified
> may be reviewed and approved by the commission as part of a proceeding for approval of new rate schedules initiated pursuant to KRS 278.190 or in a separate proceeding initiated pursuant to this section which shall be limited to a review of demand-side management issues and related rate-recovery issues as set forth in subsection (1) of this section and in this subsection.

In accordance with KRS 278.285, Columbia Gas' proposed DSM cost recovery mechanism would provide for recovery of the full cost of Commission-approved demand-side management programs, would provide for recovery of revenue lost by implementing these programs, and would allow the Company to obtain incentives designed to financial rewards for implementing cost-effective demand-side management programs.

Q: Is Columbia Gas proposed Energy Efficiency/Conservation Program Cost Recovery schedule similar to other DSM cost recovery mechanisms approved by the Commission?

A: Yes. Columbia Gas' proposed Energy Efficiency/Conservation Program Rider is similar to those approved by the Commission for the following utilities that provide natural gas distribution service: Louisville Gas and Electric Company, Atmos Energy, Duke Energy - Kentucky, and Delta Natural Gas Company. Columbia Gas' proposed DSM cost recovery mechanism was modeled after the mechanism that was recently approved by the Commission in Case No. 2008-00062 for Delta Natural Gas Company.

Q: Without a DSM cost recovery mechanism, do utilities have an incentive to pursue demand-side management strategies that would reduce sales?

A: No. In traditional regulation, utilities have a financial incentive to increase retail sales relative to historical test-year levels that were used for calculating their base rates. The incentive for utilities to maximize the "throughput" of gas sales and transportation volumes in an attempt to increase net margins is referred to as a "throughput incentive." Utility profits are reduced when demand side management and energy efficiency programs reduce sales and transportation volumes from levels that would have been obtained without these programs. Under traditional regulation, there is an incentive for utilities to increase sales and to avoid programs aimed at reducing sales. It is critical to address this throughput incentive and to provide for DSM program cost recovery if the utility is to become actively involved in demand side management and energy efficiency programs that have the potential to reduce sales.

Q: Please describe the Energy Efficiency/Conservation Program Cost Recovery component of the DSM cost recovery mechanism?

A: The EECPCR component of the DSM cost recovery mechanism would be used to recover the cost of developing and implementing demand side management and energy efficiency programs. The EECPCR component would recover all costs for demand-side management and energy efficiency programs for each twelve-month period that has been approved by the Commission. These program costs would include the cost of planning, developing, implementing, managing, and monitoring, and evaluating DSM programs. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, would be recovered through the EECPCR component.

Q: Please explain why it is necessary to create a mechanism to recover the cost of implementing demand side management and energy efficiency programs.

A: Under traditional ratemaking, utilities typically are unable to cover the costs of designing and implementing demand side management and energy efficiency programs in a timely fashion. In most regulatory jurisdictions, these program costs are expensed, which means all costs incurred for demand side management and energy efficiency are placed into rates during the year that the expense is incurred, and then only if that year is a test year for a rate filing. Between rate filings, the utility would not recover the cost of any demand side management or energy efficiency programs that were above the level of program costs included in the utility's base rates. Because a utility is unlikely to initiate a rate case due to incremental demand side management and energy efficiency program costs alone, there may be a significant delay in recovering these costs. Program costs which are above the level of program costs included in base rates would go unrecovered and would reduce earnings if these costs are not significant enough to cause a utility to file a rate case. To ensure funds are available to cover the costs of demand side management and energy efficiency programs on a timely basis, it is necessary to implement a mechanism that will recover the costs of any demand side management and energy efficiency programs that are above the levels included in base rates using a cost recovery mechanism between rate cases.

Q: How will DSM program costs be assigned to residential and commercial customers?

A: In accordance with Subsection (3) of KRS 278.285, DSM program costs will be assigned to the rate classes that directly benefit from the programs. Because Columbia Gas is currently proposing DSM programs only for residential customers, all DSM costs will be recovered from residential customers.

Q: Once DSM costs are identified for each rate class, how will the costs be recovered?

A: The costs assigned to residential customers will be converted to a customer charge ($ per customer per billing period) by dividing the DSM program costs assigned to the class by the projected annual number of customer bills . The cost assigned to commercial customers would be converted to a customer charge ($ per customer per billing period) by dividing the DSM program costs allocated to the class by the projected annual number of customer bills. Any over- or under-recovery of actual DSM program costs ultimately will be refunded or recovered through the application of the EECP Balance Adjustment.

Q: Please describe the EECP Revenue From Lost Sales component of the proposed DSM cost recovery mechanism.

A: The EECPLS component is a lost revenue adjustment mechanism ("LRAM") which would apply to all of the demand side management programs that Columbia Gas would pursue. Implementing an LRAM for all demand side management programs would allow Columbia Gas to recover the lost contributions to fixed costs associated with not selling additional units of energy because of the success of these programs in reducing natural gas consumption on and after the effective date of the tariff.

For each upcoming twelve-month period, the estimated reduction in customer usage (measured in Mcf) for the approved programs would be multiplied by the delivery charge for purposes of determining the lost revenue to be recovered. The reduction in customer usage for each program would be estimated by multiplying engineering estimates of energy savings for each demand side measure installed by the expected program results for the upcoming twelve-month period.

Next, the lost revenues for each customer class would be divided by the expected number of customer bills for the applicable customer class for the upcoming twelve-month period to determine the applicable lost revenue amount. Recovery of revenue from lost sales would be included in the EECPLS until implementation of new rates pursuant to a general rate case.

Because the revenues collected by the EECPLS component would be based on engineering estimates of energy savings, expected program results and estimated sales, there would be a true-up at the end of the twelve-month period. Any difference between the lost revenues collected by the EECPLS component and the actual lost revenues would be reconciled in future billings under the EECP Balance Adjustment component.

Q: Are there other methodologies used to address the recovery of revenue from lost sales instead of what is proposed in the proposed DSM cost recovery mechanism?

A: Yes. There are three methodologies widely used in the utility industry to protect utilities from lost revenues due to the implementation of DSM programs. First, the utility can recover the estimated revenue from lost sales by estimating the actual reduction in Mcf sales resulting from specific utility-sponsored DSM measures. The Company's proposed EECP Revenue From Lost Sales component utilizes this approach. Second, a decoupling mechanism can be implemented which decouples the utility's revenues from its sales, thus protecting the utility against reductions in sales resulting from either utility-sponsored DSM programs or energy efficiency efforts initiated by customers. A decoupling mechanism would allow the utility to recovery any reductions in net revenues (or "margins") per customer experienced by the utility subsequent to a general rate case. Third, the utility could adopt a straight fixed-variable rate design whereby all of its distribution fixed costs are recovered through a fixed monthly customer charge. Straight fixed-variable rate designs, which are common in the gas utility industry, protect the utility against lost revenues from both utility-initiated DSM measures and customer-initiated energy efficiency efforts. Consequently, the adoption of a straight fixed-variable rate design with only a fixed billing charge removes the need for the Revenues from Lost Sales component.

Q: Is Columbia Gas proposing a phased-in approach for implementing a straight fixed-variable rate design?

A: Yes. Columbia Gas is proposing to phase in a straight fixed-variable rate design over a two-year period for residential customers. During the first year, Columbia would move 50% toward a straight fixed-variable rate design and in the second year the Company would fully adopt a straight fixed-variable rate design for the residential customer class.

Q: Would Columbia Gas' proposal to transition to a straight fixed-variable rate design have an effect on the EECP Revenue From Lost Sales component of the proposed DSM cost recovery mechanism?

A: Yes. After the full implementation of a straight fixed-variable rate design during the second year of Columbia Gas' proposal, a EECPLS component would no longer be calculated. The distribution delivery component of residential base rates would be eliminated and the lost revenue amounts calculated under the EECPLS component of the mechanism would become zero for this rate class.

Q: Please describe the EECP Incentive component of the mechanism.

A: The EECPI component would be used to provide an opportunity for Columbia Gas to share in the energy savings generated by pursuing demand side management and energy efficiency programs, and would replace some of the earnings that Columbia Gas would forego by not investing in new supply-side resources. The EECPI component would be computed by multiplying the net resource savings expected from the approved programs which are to be installed during the upcoming twelve-month period multiplied by fifteen percent. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Columbia Gas' avoided costs over the expected life of the program, and will include both capacity and commodity savings. The EECPI amount summed for all programs shall be divided by the applicable expected number of customer bills for the upcoming twelve-month period to determine the EECPI.

Q: Please explain why a true-up component is needed and how it is constructed.

A: A true-up component is needed to ensure that the EECPCR, EECPLS and EECPI components of the DSM cost recovery mechanism neither over-recover nor under-recover costs. The EECP Balance Adjustment component of the DSM cost recovery mechanism provides this true-up mechanism. The EECPBA component would be calculated on a calendar year basis and would reconcile the difference between the amount of revenues actually billed through the EECPCR, EECPLS, and EECPI and the revenues which were expected to have been billed under the three components.

Q: Would the DSM cost recovery mechanism that you have described above aid in achieving the potential for demand side management on the part of Columbia Gas?

A: Yes. The DSM cost recovery mechanism described above would provide a way to recover the program costs and lost revenues association with implementing demand side management programs without the necessity of general rate cases. The cost recovery mechanism would provide the flexibility to pursue new programs as they are identified or to change program direction rapidly as cost effective program modifications were identified. By providing for the recovery of program costs, revenues from lost sales, and an incentive the Energy Efficiency/Conservation Program Cost Recovery schedule would level the playing field between demand side and supply side approaches for meeting customer energy needs and provide Columbia Gas with the motivation to pursue demand side management and energy efficiency programs by better aligning the financial interest of Columbia Gas and its customers.

Q: Would you recommend that the Commission adopt the Energy Efficiency/Conservation Program Rider you have described above ?

A: Yes, I would.

Q: Please identify the DSM programs that Columbia Gas is proposing.

A: Columbia Gas is proposing three programs targeted to residential customers: (i) an Energy Audit Program; (ii) a High-Efficiency Appliance Rebate Program; and, (iii) a Low-Income High Efficiency Furnace Replacement Program. The Energy Audit Program and the High-Efficiency Appliance Rebate Program would be generally available to all residential sales and CHOICE customers The Low-Income High Efficiency Furnace Replacement Program would only be available to customers at or below 200% of the federal poverty guidelines. At least initially, the funding for these three programs would be somewhat modest. The Company believes that it is important to gain some experience with DSM programs before making a larger commitment in this area. Columbia Gas is proposing an annual budget for all three programs of $908,000, which includes direct program costs, administrative costs and program evaluation costs.

Q: Please describe the Energy Audit Program proposed by Columbia Gas.

A: Under the Energy Audit Program, Columbia Gas will fund free energy audits to residential customers. The audits will be performed by a qualified outside contractor selected by the Company. It is anticipated that the audits will encompass the following services:

- An analysis of the dwelling's usage history and the detection of any abnormalities or trends relative to the square footage, load and surrounding dwelling usage trends;
- Checking for proper changes of the heating system filtering devices and clearance from obstructions of all return air registers;
- Inspection of outer wall switch plates and outlets for insulation protection or gasket installation;
- Checking of ceiling insulation levels;
- Inspection of duct systems;
- Checking of exterior windows and doors for unwanted leakage and heat loss;
- Identification of areas of high energy loss through thermal imaging;
- Providing options and recommendations to the occupant; and,
- Providing the occupant with an audit kit consisting of caulk, switch plate and outlet gaskets, electric outlet plugs and weather stripping.

The annual budget for this program is $200,000 based on performing an estimated 4,000 audits at a cost of $50 per audit.

Q: Please describe the High-Efficiency Appliance Rebate Program proposed by Columbia Gas.

A: Under the High-Efficiency Appliance Rebate Program, Columbia Gas will provide rebates to existing or new customers that install high efficiency appliances of 90 percent efficiency or higher on or after the effective date of the Energy Efficiency/Conservation Program Rider. Specifically, Columbia Gas will provide the following appliance rebates:

Appliance	Efficiency Level	BTU Input	Rebate
Forced Air Furnace	90% or greater	30,000 or greater	$400
Dual Fuel	90% or greater	30,000 or greater	$300
Space Heater	99%	10,000 or greater	$100
Gas Logs	99%	18,000 or greater	$100
Gas Fireplace	99%	18,000 or greater	$100

The annual budget for this program is $400,000 based on an estimated 1,600 participants for the year.

Q: Please describe the Low-Income High Efficiency Furnace Replacement Program proposed by Columbia Gas.

A: Under the Low-Income High Efficiency Furnace Replacement Program, Columbia Gas will provide up to $2,200 toward the cost of installing a high efficiency forced air furnace of 90 percent efficiency or higher for a qualifying low-income customer. Columbia Gas will partner with the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc ("CAC") to provide this service. The CAC will identify potential customers, qualify the customers, and work with its contractors to replace existing furnaces with high efficiency forced air furnaces of 90 percent efficiency or higher. By partnering with CAC, Columbia Gas of Kentucky anticipates that its Low-Income High Efficiency Furnace Replace Program can be coordinated synergistically with the Federal Weatherization Program which provides roof improvements, exterior wall insulation, attic insulation, crawl space insulation, window replacements, and refrigerator replacement and with other weatherization funds, including the Kentucky Clean Energy

Corps, which provide services to low-income customers on Columbia Gas' system. Columbia Gas' program will augment these other programs and will fill a void by providing a service not fully addressed by these other programs. The annual budget for this program is $308,000 based on an estimated 140 participants for the year.

Q: Have you prepared an attachment showing the calculation of the monthly adjustment factors proposed by Columbia Gas?

A: Yes. The monthly adjustment factors applicable to residential customers are calculated in Attachment Seelye-2. This attachment shows the calculation of the EECPCR, EECPLS, and EECPI components for the three programs proposed by Columbia Gas. There would not be a EECPBA component during the first year of operation of the Energy Efficiency/Conservation Program Rider.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service studies and developed rates for over 100 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Case No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Case Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana:	Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.
	Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.
Kansas:	Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.
Kentucky:	Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.
	Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.
	Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.
	Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.
	Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.
	Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.
	Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.
	Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.
	Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Columbia Gas of Kentucky, Inc.
Conservation/Efficiency Program Cost Recovery
Calculation of Monthly Adjustment Factors
for Schedule GSR

					Conservation/Efficiency Program Cost Recovery (CEPCR)		CEP Revenue From Lost Sales (CEPLS)		CEP Incentive (CEPI)	
Program	Estimated Participants	Est Annual Mcf Savings per Participant	Total Est Annual Mcf Savings	Estimated Cust-Months	Program Cost	CEPCR Adjustment	Annual Lost Revenues	CEPLS Adjustment	Incentive Amount	CEPI Adjustment
							$ 2.0000			
Energy Audit Program	4000	3.0	12,000.0	1,496,096	$ 200,000	$ 0.13	$ 24,000	$ 0.02	$ 104,614	$ 0.07
High Efficiency Furnace Rebate Program	1460	6.4	9,312.6	1,496,096	400,000	0.27	18,625	0.01	69,797	0.05
Low-Income High Efficiency Furnace Rebate Program	140	6.6	922.5	1,496,096	308,000	0.21	1,845	0.00	-	-
Total						$ 0.61		$ 0.03		$ 0.12
										$ 0.76

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
JAMES F. RACHER
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF JAMES F. RACHER

Q: Please state your name and business address.

A: My name is James F. Racher and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: What is your current position and what are your responsibilities?

A: I am employed by NiSource Corporate Services Company ("NCSC"). My title is Director of Demand Forecasting and Regulatory Services. As Director, my responsibilities include overseeing regulatory and demand forecasting related services for NiSource Inc. ("NiSource") subsidiaries, including regulatory compliance filings, long range forecasting, and rate case support as requested by the NiSource energy distribution companies, including Columbia Gas of Kentucky, Inc. ("Columbia" or "the Company").

Q: What is your educational background?

A. I received a Bachelor of Science in Business Administration degree, majoring in Finance, in 1987 from The Ohio State University. I also received a Master of Business Administration degree from Franklin University in 2002.

Q: Please describe your employment history.

A. I began my career with Columbia Gas distribution companies in 1988 in the Eastern Rate department as a Rate Analyst. I held various positions of increasing responsibility in the Rate and Regulatory department from 1988 to 1996, when I was promoted to the position of Team Leader of Regulatory for the Finance and Regulatory department in the Shared Services Center of the Columbia Energy Group ("CEG") distribution companies. I was promoted to Director of Regulatory Accounting in 2000, and I held that position until leaving the company in November, 2002. In May 2007, I accepted my current position in NCSC's Rate and Regulatory Services department.

Q. Have you previously testified before the Kentucky Public Service Commission or any other regulatory commissions?

A: I have not testified before the Kentucky Public Service Commission. I have testified before the Virginia State Corporation Commission and the Pennsylvania Public Utility Commission.

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

A: I am responsible for the development of the overall revenue requirement, as shown in Schedule A. I am also responsible for Schedule B, excluding B-6, and Schedules C, D, F, G, H, I and K. These schedules were all prepared under my direction and supervision. I also sponsor and support Filing Requirements 6-a, 6-b, 6-h, 6-i, 6-j, 6-k, 6-l, 6-m, 6-p, 6-q, 6-r, 6-s, 6-t and 7-a through 7-d.

Q: What is the test period and the plant valuation date in this proceeding?

A: The test period is the actual twelve months ended December 31, 2008, adjusted for known and measurable changes, and the plant valuation is as of December 31, 2008.

Q: Please describe the information presented on Schedule A.

A: Schedule A reflects Columbia's Overall Financial Summary. Schedule A, Line 8 shows the calculation of the revenue deficiency in this case of $11,565,731. This amount represents the increase in revenue that is required by Columbia to earn an overall rate of return on rate base of 9.00%, the return recommended by Columbia witness Moul. On Line 9, the requested revenue increase of $11,565,731 is the revenue that is supported by Columbia's proposed rates, and is the adjustment to revenue that Columbia is requesting in its Application.

Q: Please describe the schedules presented in Schedule B of Columbia's Application.

A: Schedule B presents Columbia's rate base. The information shown on Schedule B-1 is the jurisdictional rate base summary reflecting information from various B schedules in the Application. The plant in service and reserve for accumulated depreciation and amortization as of December 31, 2008 are summarized on Schedules B-2, B-3 and B-4. The allowance for working capital is shown on Schedule B-5. Other rate base items are shown on Schedule B-6. Schedule B-7 reflects the jurisdictional allocation factors and Schedule B-8 contains comparative balance sheets.

Q: Please describe in detail the individual supporting schedules.

A: Schedule B-2 shows the investment in gas plant in service by major property grouping as of the plant valuation date of December 31, 2008. The amount in the column labeled "Based Period Adjusted Jurisdictional" represents plant in service that is used and useful in providing gas service to Columbia's customers. Schedules B-2.1 through B-2.7 provide a more detailed presentation of the gas plant in service, including a breakdown by FERC account and information reflecting plant additions and retirement.

Schedule B-3 shows the total plant investment and the Reserve for Accumulated Depreciation and Amortization by FERC Account groupings as of December 31, 2008. Schedule B-3.1 reflects adjustments to the reserve. Columbia has not proposed any adjustments in this case.

Schedule B-3.2 lists the jurisdictional plant investment and reserve balance at December 31, 2008 for each FERC Account within each major property grouping. It also shows the proposed depreciation accrual rates, calculated annual depreciation and amortization expense on plant in service as of December 31, 2008 excluding construction work in progress in service, percentage of net salvage, average service life and curve form, as applicable, for each account. In this Application, Columbia is filing with the Commission proposed depreciation accrual rates and amortization accrual rates for tangible property. Except for the amortization rates on intangible property, the proposed depreciation and amortization accrual rates, as shown in Column G are supported by Columbia witness Spanos and are included in his study as provided in response to the Commission's standard filing requirement 6-N. The amortization rates for intangible property, which consist mostly of software costs, are established by Columbia consistent with its policy on amortization of intangible property. The calculated depreciation and amortization expense are provided by Mr. Spanos except for the amount of intangible property which is the test year level of expense.

Schedule B-4 shows construction work in progress by major property grouping at December 31, 2008. Certain balances remain in Account 107 – Construction Work in

Progress; however, the plant has been placed in service. These amounts have been identified on Schedule B-4 and have been included in Columbia's rate base.

Q: Please explain why balances remain in Account 107 when the plant has been placed in service.

A: There are many reasons that plant may be placed in service, but for accounting purposes, has not been transferred to Account 101 – Gas Plant in Service or Account 106 - Completed Construction Not Classified. An example is items that are purchased on a blanket work order, such as office equipment, computers, tools, meters, etc. These items are "in service" at the time of purchase. Another example includes specific projects that may have been flagged as "in or ready for service" however, for accounting purposes have not been moved to Account 101 or Account 106 because all invoices have not been received or billings have not been completed. In general, it takes two to three months to map and close projects from Account 107 to Account 101 or Account 106.

Q: Please describe the calculation of cash working capital and other working capital allowances as shown on Schedules B-5 and B-5.1.

A: The total working capital requirement is shown on Schedule B-5, Sheet 1, Line 6. The working capital is made up of Cash Working Capital as shown on Line 1, Materials and Supplies shown on Line 3, Gas Stored Underground on Line 4, and Prepayments shown on Line 5.

Q: Are you proposing an adjustment regarding working capital on Gas Stored Underground?

A: Yes, I am.

Q: Please describe the need for this adjustment.

A: The value of gas stored underground is included in rate base as a component of the working capital requirement. Columbia must pay for gas at the time when it is injected into storage. However, payment for the gas is storage is not received from customers until after the gas is consumed. As a result, Columbia incurs carrying costs associated with this working capital requirement.

Throughout the year, as gas is injected and withdrawn from storage, the monthly value of storage changes. The rate base value of storage gas is an average of the storage inventory values for the thirteen months ended December 2008. This storage adjustment relates to Columbia's proposed method for determining the monthly values of storage inventory.

Q: Please explain how Columbia values storage inventory.

A: Columbia utilizes annualized Last-In-First-Out ("LIFO") accounting to value gas inventory. However, the LIFO method of valuing storage does not accurately reflect the cost of gas in storage as a component of rate base. The LIFO procedure prices gas withdrawals and injections using the current year's commodity gas price. While this is an acceptable accounting practice, it is not reflective of Columbia's ongoing investment in storage.

During some months, LIFO accounting will value Columbia's storage gas at a negative dollar amount.

Q: Describe how LIFO accounting may value Columbia's storage gas as negative.

A: Using the LIFO method, gas may be withdrawn from storage at prices in excess of the inventory prices from previous storage layers. This results in negative balances on Columbia's books and records. However, gas volumes remain in the storage facilities.

Q: Please elaborate concerning the use of LIFO for computing the rate base value of gas in storage.

A: Even with substantial volumes in storage, the LIFO method may result in a negative storage asset, during winter months. The use of LIFO balances effectively would assume that Columbia has a source of funds from gas in storage that would reduce the Company's working capital needs for several months during an annual period. In other words, the use of LIFO for computing the rate base value of gas in storage does not provide consideration for injections into storage at current rates prior to withdrawals from storage at the same current rates.

Q: What is Columbia's proposal for this working capital issue?

A: Columbia proposes to incorporate storage in rate base at the average annual cost of gas in storage. Using the average annual cost of gas to price storage recognizes the long-term aspect of the capital commitment necessary to hold gas for customers' future consumption.

Q: Please describe the long-term nature of gas in storage.

A: Storage is a critical component of Columbia's supply portfolio and is integral to Columbia's ability to serve the temperature-sensitive demand of its core market customers in a reliable manner during the winter heating season. Gas in storage needs to be injected prior to it being available for use. Storage injections generally begin in April and continue through October. Payments for gas used to build a volumetric storage balance are made as the volumes are injected into storage. During the heating season, these volumes are withdrawn and paid for by customers. Columbia's storage balance is typically at its peak at the beginning of November each year. The storage balances are typically at, or near, their lowest levels at the end of March each year.

Q: Please identify and describe any attachments to your testimony.

A: Attachment JFR-1 supports this testimony. Page 1 of Attachment JFR-1 includes the monthly detail for storage balances during the historic test year and the resulting thirteen-month average balance ($32,765,396). The second page of Attachment JFR-1 recalculates the historic thirteen-month balance using an average rate. This average rate was developed by considering all injections in storage and available for use at October 2008.

Q: How did Columbia value the portion of storage which is long-term in nature?

A: The October 2008 storage balance was $81,472,934 and the volumetric balance was 11,003,684 Mcf. The resulting average rate is $7.4042 per Mcf.

Q: Why did you use the October 2008 storage balance in valuing storage?

A: The October 2008 storage balance and volumes are known and measurable amounts. At the end of October, Columbia's injections into storage are generally complete. The average storage rate should be valued at a peak facility time, thus making October the best month to use for valuing storage.

Q: Please summarize Columbia's proposal related to the rate base value of gas in storage.

A: Since the LIFO method does not accurately reflect the cost of gas in storage as a component of rate base, Columbia proposes to incorporate storage in rate base at the average annual cost of gas in storage. As shown on Page 2 of Attachment JFR-1, Columbia's proposal results in a thirteen month average balance of $48,234,292.

Q: How was the Cash Working Capital Allowance developed?

A: Cash Working Capital is calculated by taking total operation and maintenance expenses for the twelve months ended December 31, 2008 (excluding gas costs) and multiplying by 1/8 or 12.25%. This method, commonly referred to as the "formula method," is the traditional methodology that has been approved by the Commission in Columbia's previous rate filings.

Q: What is the theory behind using the formula method to calculate the Cash Working Capital Allowance?

A: The formula method recognizes that, on average, there is a 45 day lag between the time when expenses are paid and revenue is collected in providing service. The 45 day lag represents approximately 1/8 of a year, so 1/8 of the test period's operation and maintenance expenses are assumed to be a reasonable approximation of Columbia's cash working capital needs.

Q: How did you calculate the other working capital items for the test period?

A: All of the other working capital items were calculated on Schedule B-5.1 by taking an average of the monthly balances for the thirteen months ended December 31, 2008, due to the monthly fluctuations in these balances. Using a thirteen month average balance allows the entire test period activity to be considered in the rate base calculation. The Commission has accepted this method in prior rate proceedings.

Q: Did you include Kentucky Public Service Commission ("KPSC") fees in the prepaid portion of working capital requirements?

A: No. Columbia has not included the balance as recognized on the books and records as a prepayment as a use of working capital since the Commission has consistently denied an allowance for this item in the past.

Q: Please explain Schedule B-7.

A: This schedule reports the allocation factors used to determine the jurisdictional percentage of gas plant necessary to determine the gas rate increase requested in this Application. This schedule indicates that 100% of the costs are jurisdictional since there are no non-jurisdictional gas customers served within Columbia's service territory.

Q: Did you prepare comparative balance sheets as required by Commission regulation 807 KAR 5:001, Section 10?

A: Yes, Schedule B-8 contains comparative balance sheet information required pursuant to 807 KAR 5:001, Section 10.

Q: Please continue with the next schedule that you are supporting.

A: Schedule C-1 reflects Columbia's pro forma Operating Income Summary for the twelve months ended December 31, 2008. This schedule includes the operating income summarized at both current rates and proposed rates. The revenue at proposed rates was developed by adding the revenue increase to the current operating revenues. The related increase to expenses and taxes on the proposed revenue increase was subtracted from the current adjusted operating results to determine the jurisdictional pro-forma amounts and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1.

Q: What is reflected in Schedule C-2?

A: Schedule C-2 shows the operating results for the twelve months ended December 31, 2008 at both unadjusted and adjusted levels.

Q: Please describe Schedule C-2.1.

A: Schedule C-2.1 sets forth the detail of Columbia's unadjusted operating results for the twelve months ended December 31, 2008. The operating results as shown on this Schedule C-2.1 are listed by account and are summarized on Schedule C-2.

Q: Please explain Schedule C-2.2.

A: Schedule C-2.2 shows a comparison of gas revenue and expense for the twelve months ended December 31, 2008 to the twelve months ended December 31, 2007 by FERC account. It also contains monthly comparison for each month in the test period. Variances from prior periods are given in dollars and percentages for the year.

Q: Have you made any adjustments to the operating results that are shown on Schedule C-2.1?

A: Yes, Schedule D-1 is a summary of the detailed adjustments to test period operating revenues and operating expenses as set forth in Schedules D-2.1 through D-2.13. These adjustments show the test period revenue and expense at the level that would have been incurred if known and measurable changes had been in effect during the entire test period. These adjustments are necessary to develop rates at a level that reflects the current and ongoing level of costs that are to be recovered during the period of time the rates are in effect.

Q: How are the tax effects of these adjustments shown on your schedules?

A: Taxes are adjusted to reflect those applicable changes resulting from the adjustments described in my testimony, including taxes other than income taxes, and state and federal income taxes. These tax adjustments along with the rates used to develop these adjustments are shown for each individual adjustment on Schedule D-1.

Q: Did Columbia adjust revenue for the test year?

A: Yes, Schedule D-2.1 reflects an annualization of base revenues, which adjusts actual revenues to a level that would have been recognized if the current rates and customers had existed during the entire test period. It reflects several revenue and expense adjustments. First, revenue has been adjusted for weather normalized sales volumes for the twelve months ended December 31, 2008. Second, revenues and related gas costs for the twelve months ended December 31, 2008 have been calibrated to reflect the annualization of sales and transportation volumes from customer levels as of December 31, 2008. Finally, annualized revenue reflects an adjustment to reconcile the Energy Assistance Program ("EAP") surcharge revenue with EAP expense.

The calculations of the weather normalization and annualized year-end customer adjustments were developed by Columbia witnesses Balmert and Efland and are supported in their testimony. Schedule D-2.1 also reflects the annualization of gas cost recovery revenue based on the most current gas cost recovery rate in effect. Operating expenses and Taxes Other than Income have also been adjusted for the effect of uncollectible accounts and the KPSC assessment on the annualized test year revenue. These adjustments are summarized on Schedule D-1, Sheet 1.

Q: What adjustment is included in Schedule D-2.2?

A: Schedule D-2.2 reflects an adjustment to provide for recognition of annualized labor costs based on employee count and labor rates at December 31, 2008. The schedule reflects an adjustment to include expected merit increases for union employees, including overtime and premium costs, effective with wages beginning December 1, 2009. This schedule also reflects a 3.0% increase for all other employees. This 3.0% increase is anticipated to be effective March 1, 2009, for non-exempt employees and front line leaders and September 1, 2009 for other exempt employees. The total adjustment increases operating expense by $544,186 after consideration for capitalized costs.

Q: Please explain the adjustment shown on Schedule D-2.3.

A: Schedule D-2.3 develops an adjustment to increase the test year incentive compensation level to an anticipated future level. This schedule removes an out of period adjustment from Columbia's per books test year level and adjusts to an anticipated level using Columbia's recent historic incentive program parameters.

Q: Has Columbia experienced an increase in the costs of its major employee benefits?

A: Yes, Schedule D-2.4 also reflects anticipated significant future increases. The total benefit adjustment shown on Schedule D-2.4 is $1,646,119 of which Other Post Employment Benefit ("OPEB") costs are increased by $262,388 for both Medical and Group Life, Employee Insurance Plans are increased by $289,387, Pensions and Retirement Income is increased by $1,103,598 and Thrift Plan is decreased by $9,254. The OPEB and Pension and Retirement Income costs are impacted by fluctuations in trust asset returns which have been affected by the returns available in the market. Columbia witness Konold will discuss OPEB and Pension and Retirement Income along with a proposed reconciling mechanism for costs incurred subsequent to those included in this application.

Q: Please explain the postage expense adjustment shown on Schedule D-2.5.

A: Schedule D-2.5 shows an adjustment to test year postage expense to reflect the postage rate increase announced by the United States Postal Service to be effective May 11, 2009.

Q: Have you reflected the new depreciation rates as proposed by Columbia witness Spanos?

A: Yes, Schedule D-2.6 reflects an increase in depreciation expense based on proposed depreciation rates filed in this proceeding and plant in service at December 31, 2008. The resulting adjustment is $2,353,180. This adjustment includes no change to the amortization levels as of December 31, 2008.

Q: Is Columbia proposing to recover costs incurred in preparing this case?

A: Schedule D-2.7 reflects an adjustment to operating expense to reflect the estimated costs for the development of this case. This includes the costs of the legal notice, consultants retained, legal fees, and miscellaneous costs such as travel and supplies expense. The amount also includes the unamortized balance of rate case expense from Case No. 2007-00008. The total anticipated amount of $280,904 has been divided by two years, which is the proposed amortization period. This amortization period represents the approximate time period since

Columbia's last rate case. The resulting adjustment is an increase over test year expense of $87,871.

Q: Have you made any adjustments to the test year level of NiSource Corporate Services Company's charges?

A: Yes. Columbia's test year level of NCSC costs charged to expense was $9,044,321, which is the sum of amounts shown in the column titled "Total Per Books" on Lines 17 and 19 of Schedule D-2.8. This amount is not representative of Columbia's going level of costs, as it includes Columbia's portion of non-recurring and non-recoverable cost that have been excluded in this adjustment. Adjustments have also been made to reflect projected ongoing NCSC costs increased for labor and benefits, the IBM contract cost level, and a decrease in annualized incentive compensation.

Q: What level of NCSC costs did you include in your adjustment?

A: As shown on Schedule D-2.8 in the column titled "Total Amount", the sum of lines 17 and 19 reflects $9,148,390 of NCSC costs which represents Columbia's projected calendar year 2009 level of NCSC costs, net of capitalization. The net adjustment is $104,069.

Q: What services does NCSC provide to Columbia?

A: Corporate Services provides professional and technical services in areas which include accounting ; auditing; budget; business promotion; corporate; electronic communications; employee services; engineering and research; gas dispatching; information technology; information services; insurance; legal; office space; operations support and planning;

purchasing, storage and disposition services; rate; tax; transportation; treasury; and customer billing, collection, and contact services. These same services are provided to all affiliates on a system-wide basis.

Q: How does Columbia benefit from the services provided by NCSC?

A: NCSC was established to provide centralized services economically and efficiently. The rendering of services on a centralized basis enables the affiliates to realize substantial economic and other benefits, including efficient use of personnel and equipment, and the availability of personnel with specialized areas of expertise and equipment, which the affiliate could not economically maintain on an individual basis. Thus, NCSC offers individual distribution companies, including Columbia, access to the depth and experience of personnel that may not otherwise be available to an entity of its size.

Q: Please explain the adjustment shown on Schedule D-2.9.

A: Schedule D-2.9 reflects the annualization of property and liability insurance expense at levels in effect at the end of the test year. Corporate insurance expense is expensed on a fiscal year ending June. Therefore, the test year includes a partial year at prior rates and a partial year at current rates. This adjustment of ($27,029) annualizes property and liability insurance expense at the current level.

Q: Have you adjusted Columbia's payroll taxes for the proposed adjustment in wages?

A: Yes, the adjustment reflected on Schedule D-2.10 annualizes test year-end FICA taxes to reflect the taxes related to increased payroll as shown on Schedule D-2.2 and decreased incentive compensation as shown on Schedule D-2.3. The adjustment also recognizes an increase in the individual level of maximum pay subject to Social Security. The total adjustment is $41,016.

Q: What is the purpose of the adjustment shown on D-2.11?

A: Schedule D-2.11 reflects the annualization of property tax levels in effect at the end of the test year. This adjustment totals $6,113.

Q: Please explain the adjustment shown on D-2.12.

A: Schedule D-2.12 reflects the elimination from the test year of non-recurring legal expenses related to a settlement with a marketer. This adjustment totals $39,392.

Q: In compliance with Commission regulation KAR 5:016, did you eliminate any promotional and/or institutional advertising costs incurred by Columbia?

A: Columbia's test year expense level does not include advertising expenditures for promotional or institutional advertising as specifically disallowed as shown on Schedule D-2.13.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2008

Line		LIFO							
		MCF			Rate	Dollars			
No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Dec-07								
2				8,238,790	$6.0249				$49,637,944
3									
4	Jan-08								
5		(7,460)	(3,393,179)	4,838,151	$8.9880	($67,050)	($30,497,893)		$19,073,001
6	YTD rate adjustment								
7	Feb-08								
8		28,374	(2,485,139)	2,381,386	$9.2530	$262,545	($22,994,991)		($3,659,446)
9	YTD rate adjustment	(7,460)	(3,393,179)		$0.2650	($899,192)	($1,977)	($901,169)	($4,560,615)
10	Mar-08								
11		198,810	(1,469,664)	1,110,532	$10.3370	$2,055,099	($15,191,917)		($17,697,433)
12	YTD rate adjustment	20,914	(5,878,318)		$1.0840	$22,671	($6,372,097)	($6,349,426)	($24,046,859)
13	Apr-08								
14		851,463	(170,336)	1,791,659	$10.2190	$8,701,100	($1,740,664)		($17,086,422)
15	YTD rate adjustment	219,724	(7,347,982)		($0.1180)	($25,927)	$867,062	$841,134	($16,245,288)
16	May-08								
17		1,877,996	(1,921)	3,667,734	$11.0250	$20,704,906	($21,179)		$4,438,439
18	YTD rate adjustment	1,071,187	(7,518,318)		$0.8060	$863,377	($6,059,764)	($5,196,388)	($757,948)
19	Jun-08								
20		1,785,822	0	5,453,556	$11.8800	$21,215,565	$0		$20,457,617
21	YTD rate adjustment	2,949,183	(7,520,239)		$0.8550	$2,521,551	($6,429,804)	($3,908,253)	$16,549,364
22	Jul-08								
23		2,118,057	0	7,571,613	$12.0210	$25,461,163	$0		$42,010,527
24	YTD rate adjustment	4,735,005	(7,520,239)		$0.1410	$667,636	($1,060,354)	($392,718)	$41,617,809
25	Aug-08								
26		1,517,643	0	9,089,256	$11.6880	$17,738,211	$0		$59,356,021
27	YTD rate adjustment	6,853,062	(7,520,239)		($0.3330)	($2,282,070)	$2,504,240	$222,170	$59,578,191
28	Sep-08								
29		1,295,318	(174,336)	10,210,238	$11.0150	$14,267,928	($1,920,311)		$71,925,807
30	YTD rate adjustment	8,370,705	(7,520,239)		($0.6730)	($5,633,484)	$5,061,121	($572,364)	$71,353,444
31	Oct-08								
32		785,062	8,384	11,003,684	$11.5140	$9,039,204	$96,533		$80,489,181
33	YTD rate adjustment	9,666,023	(7,694,575)		$0.4990	$4,823,345	($3,839,593)	$983,753	$81,472,934
34	Nov-08								
35		(64,936)	(845,938)	10,092,810	$11.5840	($752,219)	($9,799,346)		$70,921,369
36	YTD rate adjustment	10,451,085	(7,686,191)		$0.0700	$731,576	($538,033)	$193,543	$71,114,912
37	Dec-08								
38		11,482	(865,848)	9,238,444	$11.5293	$132,379	($9,982,621)		$61,264,670
39	YTD rate adjustment	10,386,149	(8,532,129)		($0.0547)	($568,122)	$466,707	($101,415)	$61,163,255
40									
41	Thirteen Month Average Account 164 / 242								$32,765,396

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2008

Line		Average - 13 months ended December 31, 2008							
		MCF			Rate	Dollars			
No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Oct-08			11,003,684	$7.4042				$81,472,934
2									
3	Dec-07			8,238,790	$7.4042				$61,001,649
4	Jan-08	(7,460)	(3,393,179)	4,838,151	$7.4042	($55,235)	($25,123,776)		$35,822,638
5	Feb-08	28,374	(2,485,139)	2,381,386	$7.4042	$210,087	($18,400,466)		$17,632,258
6	Mar-08	198,810	(1,469,664)	1,110,532	$7.4042	$1,472,029	($10,881,686)		$8,222,601
7	Apr-08	851,463	(170,336)	1,791,659	$7.4042	$6,304,402	($1,261,202)		$13,265,802
8	May-08	1,877,996	(1,921)	3,667,734	$7.4042	$13,905,058	($14,223)		$27,156,636
9	Jun-08	1,785,822	0	5,453,556	$7.4042	$13,222,583	$0		$40,379,219
10	Jul-08	2,118,057	0	7,571,613	$7.4042	$15,682,518	$0		$56,061,737
11	Aug-08	1,517,643	0	9,089,256	$7.4042	$11,236,932	$0		$67,298,669
12	Sep-08	1,295,318	(174,336)	10,210,238	$7.4042	$9,590,794	($1,290,819)		$75,598,644
13	Oct-08	785,062	8,384	11,003,684	$7.4042	$5,812,756	$62,077		$81,473,477
14	Nov-08	(64,936)	(845,938)	10,092,810	$7.4042	($480,799)	($6,263,494)		$74,729,184
15	Dec-08	11,482	(865,848)	9,238,444	$7.4042	$85,015	($6,410,912)		$68,403,287
16									
17	Thirteen Month Average Account 164 / 242								$48,234,292

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

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

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

Columbia Gas of Kentucky, Inc
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CEG	Columbia Energy Group
DCF	Discounted Cash Flow
FFO	Funds from Operations
FOMC	Federal Open Market Committee
g	Growth rate
GAAP	Generally Accepted Accounting Principles
GCR	Gas Cost Recovery Mechanism
GDP	Gross Domestic Product
IGF	Internally Generated Funds
LCR	
LDC	Local Distribution Companies
Lev	Leverage modification
LT	Long Term
MLPs	Master Limited Partnerships
P-E	Price-earnings
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

PREPARED DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q: What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Public Service Commission of the Commonwealth of Kentucky (the "Commission") should allow Columbia Gas of Kentucky, Inc., ("Columbia of Kentucky" or the "Company") an opportunity to earn on its gas jurisdictional rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data set forth in Attachments PRM-1 through PRM-14. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

Q: Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A: My conclusion is that the Company's cost of common equity is 12.25% and that the Commission should adopt this cost rate as part of a reasonable rate of return. With this return, I have presented the weighted average cost of capital for the Company as shown on Attachment PRM-1. The weighted average cost of capital is based upon Columbia of Kentucky's capitalization adjusted for market based capital structure ratios (see page 1 of Attachment PRM-5). The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

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

A: Columbia of Kentucky is a wholly-owned subsidiary of Columbia Energy Group ("CEG"), which in turn is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). CEG is engaged in natural gas transmission and storage and the distribution of natural gas. NiSource is a holding company that owns Northern Indiana Public Service Company ("NIPSCO"), a combination electric and gas utility operating in Indiana), Bay State Gas Company (which operates in Massachusetts), and other energy related investments.

The Company provides natural gas distribution service to approximately 138,000 customers in central and eastern Kentucky. Since the Company's last rate case, its residential and commercial customer count has declined by 1,885. Throughput to its customers in 2008 was represented by approximately 20% to residential customers, 11% to commercial customers, 4% to industrial, sales for resale and off-system customers, and 65% to transportation customers. Industrial customers comprise just 182 customers, or approximately one-tenth of one percent of the Company's customers. This means that the energy needs of a few customers can have a significant impact on the Company's operations.

The Company's flowing gas is provided by transportation arrangements with interstate pipelines and with local producers. The Company supplements its flowing gas supplies with gas withdrawn from underground storage. Approximately 77% of the Company's customers use natural gas for space heating purposes. Also, approximately 21% of its customers utilize the Company's transportation service.

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

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

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

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

Q: How have you measured the cost of equity in this case?

A: The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a gas group of seven (7) gas companies. The companies are identified on page 2 of Attachment PRM-3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q: Please explain the selection process used to assemble the Gas Group?

A: I began with the universe of gas utilities contained in the basic service of The Value Line Investment Survey, which consists of twelve companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. Through the application of my screening process, I eliminated five companies, which were Laclede and Nicor because they lack a weather normalization feature in their tariffs, NiSource due to its electric operations and its natural gas pipeline and storage operations, Southwest Gas due to its location where service is provided in an arid region of the U.S., and UGI Corporation because of its highly diversified businesses. The remaining seven companies are included in my Gas Group.

Q: How have you performed your cost of equity analysis with the market data for the Gas Group?

A: I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized. This is to say, by employing group average data, rather than individual company analysis; I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q: Please summarize your cost of equity analysis.

A: My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches. As I will establish below, the results of the market-based models (i.e., DCF, RP, and CAPM) for the Gas Group require an upward adjustment of 0.75% to recognize the Baa3/BBB- credit quality of the Company's parent as compared to the Gas Group's A3/A credit quality.

	Gas Group	Columbia of Kentucky
DCF	11.10%	11.85%
RP	12.22%	12.97%
CAPM	12.88%	13.63%
Comparable Earnings	13.70%	13.70%
Measures of Central Tendency:		
Average	12.48%	13.04%
Median	12.55%	13.30%
Mid-point	12.40%	12.78%

As will be discussed later in my testimony, the Company's cost of equity is higher than the Gas Group because its credit quality is weaker. As such, an average of the results of the DCF, Risk Premium and CAPM models is 12.07% (11.10% + 12.22% + 12.88% = 36.20% ÷ 3) for the Gas Group and is 12.82% (11.85% + 12.97% + 13.63% = 38.45% ÷ 3) for the Company. Alternative combinations of these results provide 11.66%, which is the average of DCF and Risk Premium (11.10% + 12.22% = 23.32% ÷ 2) for the Gas Group and 12.41% (11.85% + 12.97% = 24.82% ÷ 2) for the Company. The average of DCF and CAPM is 11.99% (11.10% + 12.88% = 23.98% ÷ 2) for the Gas Group and 12.74% (11.85% + 13.63% = 25.48% ÷ 2) for the Company. From these results, the return for the Company would be 12.25% in recognition of its higher credit quality risk profile. My recommended rate of return on common equity of 12.25% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events, such as unexpected spikes in the cost of purchased products and other expenses. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Indeed, in a recent study dated December 9, 2008, prepared for the American Gas Foundation, it was noted that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. Furthermore, the report specifically found that returns below 10% would trigger broad disenchantment with LDC investment.

NATURAL GAS RISK FACTORS

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

A: Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for large volume customers. Of particular concern for the Company is the lack of growth as described in the testimony of Mr. Miller. Mr. Miller also explains the impact of the current recession on throughput to large volume users.

Natural gas utilities have focused increased attention on safety and reliability issues. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues.

Q: How does the Company's throughput to industrial and transportation customers affect its risk profile?

A: The Company's risk profile is strongly influenced by natural gas sold/delivered to customers engaged in petroleum refining, automobile assembly, and the manufacturing of steel, glass, and chemicals, as discussed by Mr. Miller. The throughput to the Company's industrial/transportation customers represents 65% of total throughput, although this class contains only 182 customers. Indeed, throughput to its ten largest customers represents 74% of 2009 forecast LCR volumes. Large volume users that have traditionally used transportation service and also have the ability to bypass the Company's facilities. Approximately 69% of the throughput of its ten largest customers is subject to the threat of bypass. The Company has been proactive to the threat of bypass by working with its customers that are in close proximity to interstate pipelines.

Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on its operations from facilities located outside the Company's service territory.

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

A: The Company is required to undertake investments to maintain and upgrade existing facilities in its service territories. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company has approximately 518 miles of its distribution mains that are to be replaced pursuant to the accelerated main replacement program. Also, the Company has 14,137 of its services that will also be replaced along with its accelerated main replacement program. The Company projects its net construction expenditures will be $70.9 million during the period 2009-2014. Over this period, these capital expenditures will represent approximately 45% ($70.9 million ÷ $156.0 million) of its net utility plant at December 31, 2008. As previously noted, a fair rate of return represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its needs on reasonable terms.

Q: Does your cost of equity analysis and recommendation take into account the weather normalization adjustment ("WNA") that has been implemented by the Company?

A: Yes. The WNA is intended to separate revenues from variations in sales related to usage caused by variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in a test year context. My cost of equity analysis that provides a 12.25% rate of return on common equity takes into account the Company's WNA.

Q: Do the LDCs included in your Gas Group already have tariff mechanisms similar to the WNA and other tariff features designed to stabilize revenues?

A: Yes, and therefore my analysis already reflects the impacts of the WNA and other revenue stabilization mechanisms on investor expectations through the use of market-determined models. All of the companies in my Gas Group already have some form of revenue stabilization mechanism. As such, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust revenues for abnormal weather and other occurrences.

Other companies in the Gas Group also have been allowed to implement a variety of mechanisms to deal with issues such as infrastructure rehabilitation, bad debt expenses, and conservation expenditures. The trend in the industry is to stabilize the recovery of fixed costs which are unaffected by usage.

Q: How do investors assess the risk to an LDC for variations in customer usage caused by weather?

A: Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a WNA.

That is not to say there are no benefits to WNA and other revenue stabilization mechanisms. Variations in weather can significantly affect customers' bills and the Company's cash flow. Fluctuations in bad debt expense from year to year, which may also be driven in part by variations in weather, also affect the Company's cash flow. Therefore, the Company can be expected to realize a short-term benefit of improved or at least more predictable liquidity as a result of these mechanisms.

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

A: Yes. As part of this case, the Company is proposing to implement an aggressive conservation program, and implement rate design changes. My cost of equity analysis that provides a 12.25% rate of return on common equity takes these measures into account.

Q: How have you addressed this issue?

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

Q: How should the Commission respond to the issues facing the natural gas utilities and, in particular, the Company?

A: The Commission should recognize and take into account the heightened competitive environment and the risk it poses in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to risk related to earnings attrition and regulatory lag, especially in the context of a historical test year, since its costs are rising each year.

FUNDAMENTAL RISK ANALYSIS

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

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

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

A: The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Attachment PRM-4.

Q: What companies comprise the gas group?

A: My Gas Group consists of the following companies: AGL Resources, Inc., Atmos Energy Corp., New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., South Jersey Industries, Inc., and WGL Holdings, Inc.

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

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

Q: How do the bond ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A: Presently, Columbia of Kentucky has no bond rating because its debt is owned by an affiliate. The corporate credit rating ("CCR") for NiSource is BBB- from Standard and Poor's Corporation ("S&P"), and the Long Term ("LT") issuer rating is Baa3 from

Moody's Investors Services ("Moody's"). The ratings for NiSource are at the bottom of the investment grades. The ratings for NiSource were recently affirmed after it successfully implemented part if its 2009 financing plan which included the issuance of $600 million of senior unsecured notes and a $265 million term loan. For the Gas Group, the average LT issuer rating is A3 by Moody's and the average CCR is A by S&P, as displayed on page 2 of Attachment PRM-3. The LT issuer rating by Moody's and the CCR designation by S&P focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is Baa1 by Moody's and BBB+ by S&P, as displayed on page 3 of Attachment PRM-4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q: Due to the difference in credit quality ratings between the parent of Columbia of Kentucky and the Gas Group, does this point to a higher cost of equity for the Company?

A: Yes. As noted above, the cost of equity consists of a utility's cost of debt plus the additional compensation required in recognition of the more risky position of common equity. In this case, the Company's credit quality is linked to the Baa3/BBB- ratings of NiSource, while the credit quality ratings of the Gas Group is A3/A. These credit quality rating differences indicate that the Company's cost to attract debt is higher than the Gas Group. This situation also translates into a higher cost of equity. The cost of debt comparison between A and Baa rated debt is shown below, and is taken from the bond yields shown on page 2 of Attachment PRM-11.

Period	Yield Differential Baa v. A
2003-2007 Average	0.25%
2008	0.71%
Through February 2009:	
Twelve-Month Average	0.90%
Six-Month Average	1.27%
Three-Month Average	1.52%

The comparisons shown above indicate that the spread in yields attributed to variations in credit quality has expanded significantly during the recent credit crisis that I will discuss below. As such, these data indicate that the Company's cost of equity exceeds the indication of the Gas Group by at least seventy-five basis points (i.e., 0.75%) in this market environment.

Q: How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A: The broad categories of financial data that I will discuss are shown on Attachment PRM-2, PRM-3, and PRM-4. The data cover the five-year period 2003-2007 and 2004-2008 for the Company. The 2003 to 2007 time period was employed for the Gas Group because 2008 annual data is presently unavailable from S&P Compustat. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is much smaller than the average size of the Gas Group, and very much smaller than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Columbia of Kentucky and the Gas Group.

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

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

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on total capital were 63.1% for Columbia of Kentucky, 53.6% for the Gas Group and 43.5% for the S&P Public Utilities.

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

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.085 (0.9% ÷ 10.6%) for the Company, 0.041 (0.5% ÷ 12.3%) for the Gas Group, and 0.112 (1.3% ÷ 11.6%) for the S&P Public Utilities. The Company's rates of return were more variable than the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 91.1% for the Company, 88.3% for the Gas Group, and 84.4% for the S&P Public Utilities. The higher operating ratios for the Company can be attributed in part to its historically low level of profitability. The Company had the highest operating ratios among the groups.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 5.26 times for the Company, 4.31 times for the Gas Group and 3.11 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective

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

income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Without a statement of cash flows, an IGF percentage has not been calculated for the Company. Historically, the five-year average percentage of IGF to capital expenditures was 94.7% for the Company, 97.6% for the Gas Group and 106.5% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. [3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.70 as the average for the Gas Group (see page 2 of Attachment PRM-3) and 0.80 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-4).

Q: Please summarize your risk evaluation.

A: While the Gas Group in certain respects provides useful evidence of the cost of equity, the Company's capital costs are higher due to its greater risk. The Company's higher

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

risk is revealed by the lower credit quality ratings of NiSource, its smaller size, its higher earnings variability, its higher operating ratio, and its weaker IGF to construction. As such, the cost of equity for the Gas Group would only partially compensate for the Company's higher risk and therefore requires an upward adjustment for the factors noted above. Therefore, the Gas Group's indicated cost of equity must be adjusted upward by 0.75% for application to the Company in this case.

CAPITAL STRUCTURE RATIOS

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

A: As explained previously, Columbia of Kentucky is wholly-owned by CEG and CEG is a wholly-owned subsidiary of NiSource. In prior cases for Columbia of Kentucky, the capital structure of CEG was used to calculate the Company's weighted average cost of capital. Today, NiSource Finance Corporation issues debt directly to outside investors for the benefit of all of the subsidiaries of NiSource, including CEG and Columbia of Kentucky. However, use of the NiSource consolidated capital structure in this case for rate of return purposes creates a number of problems related to debt issued to finance pollution control facilities of NIPSCO, debt issued by non-regulated subsidiaries of NiSource, and significant amounts of capital issued to finance the goodwill related to the acquisition of CEG.

Q: What approach have you taken in this case to develop capital structure ratios that are appropriate for ratesetting purposes?

A: I have analyzed the capital structure issue of Columbia of Kentucky by reference to the capital structure ratios employed by other firms engaged in the gas distribution business, i.e., the Gas Group. I employed the Gas Group capital structure as the foundation for capital structure ratios of Columbia of Kentucky.

Q: Please describe your capital structure proposal.

A: For the Columbia of Kentucky, I analyzed the capital structure ratios of the Gas Group to develop reasonable ratios. That data is shown historically on Attachment PRM-3. There, the common equity ratio was 54.6% at year-end 2007, based upon permanent capital excluding short-term debt. Attachment PRM-3 also shows ratios that include short-term debt. However, those ratios are not useful in this regard because the short-term debt amounts represent the balances at fiscal year-end for each company in the Gas Group. For gas companies, short-term debt fluctuates substantially during the year related to seasonal working capital needs associated with customer accounts receivable, which peak during the heating season, and to the financing of stored gas inventory, which accumulates prior to the heating season. As such, short-term debt when it is considered for a gas utility is usually stated on an average basis.

Q: What capital structure ratios do investors expect for the Gas Group?

A: The Value Line service provides forecasts of the capital structure ratios. Since investors formulate their expectations by considering analysts' forecasts, consideration should be given to forecast capital structure ratios. The forecast common equity ratios are provided below based upon data widely available to investors from Value Line.

Company	2008	2009	2011-13
AGL Resources, Inc.	51.0%	52.0%	54.5%
Atmos Energy Corporation	49.0%	49.0%	49.0%
New Jersey Resources Corp.	61.5%	62.0%	67.5%
Northwest Natural Gas Co.	53.0%	52.0%	52.0%
Piedmont Natural Gas Compan)	52.5%	50.0%	53.0%
South Jersey Industries, Inc.	59.0%	59.5%	59.5%
WGL Holdings, Inc.	62.3%	63.5%	66.5%
Average	55.5%	55.4%	57.4%

Source: The Value Line Investment Survey, December 12, 2008

From these data, as well as the historical trends, it is my opinion the Columbia of Kentucky would have a capital structure comprised of 45% long-term debt and 55% common equity if it were an independent company that had outside investors providing debt and equity directly.

Q: How have you used this data to develop capital structure ratios for the Company for ratesetting purposes?

A: I have used a 45% long-term debt ratio and a 55% common equity ratio to recast the Company's capitalization. On Attachment PRM-5, I have shown the Company's actual capitalization and capital structure ratios at December 31, 2008. For short-term debt, I have utilized a thirteen month average for the test year. Since the Company's rate base of $181.790 million exceeds its capitalization, my analysis began with the Company's rate base and I deducted the thirteen-month average balance of short-term debt from it. I then applied the hypothetical capital structure ratios of 45% long-term debt and 55% common equity to the remainder of the rate base. The resulting capital structure ratios for ratesetting purposes are 42.56% long-term debt, 5.42% short-term debt, and 52.02% common equity, as shown on Attachment PRM-5.

COST OF SENIOR CAPITAL

Q: What cost rate have you assigned to the debt portion of the capital structure?

A: The determination of the debt cost rate is essentially an arithmetic exercise because the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. Attachment PRM-6 provides the actual embedded cost of long-term debt at December 31, 2008 for Columbia of Kentucky. Since the hypothetical capital structure contains more debt than the actual amount outstanding, I priced the additional hypothetical amount of debt at 7.44% following the formula used by the Company for issuing debt to NiSource Finance. In this case, the yield on 10-year Treasury obligations was 2.89% on March 12, 2009 plus a spread of 4.55% for Baa3/BBB- rated debt taken from the Reuters Corporate Spreads for Utilities. The resulting interest rate is 7.44% (2.89% + 4.55%). I will adopt the 5.76% embedded cost of long-term debt at December 31, 2008, as shown on Attachment PRM-6. The cost of short-term debt was taken from Schedule J-2 of the Company's Standard Filing Requirements, which represents a 3-month average for the fourth quarter of 2008.

COST OF EQUITY – GENERAL APPROACH

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

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

It also is important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and have arrived at a cost of equity of 12.25% for the Company.

DISCOUNTED CASH FLOW ANALYSIS

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

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

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

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

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

A: The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended February 2009, the monthly dividend yields of the Gas Group are shown graphically on Attachment PRM-7. The monthly dividend yields shown on Attachment PRM- 7 reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ending February 2009, the average dividend yield was 4.03% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 4.13% and 4.30%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 4.13% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs, while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix E. That adjusted dividend yield is 4.26% for the Gas Group.

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

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

Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

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

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

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

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

A: I have considered the growth in the financial variables shown on Attachment PRM- 8 and Attachment PRM- 9. The bar graph provided on Attachment PRM- 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM- 8, the historical growth of earnings per share was in the range of 5.21% to 8.36% for the Gas Group.

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

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications.

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

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

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

A: As to the five-year forecast growth rates; Attachment PRM- 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.67% by IBES/First Call, 6.71% by Zacks, and 5.86% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 5.86%) than the dividends per share (i.e., 4.21%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q: What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A: A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, while history cannot be ignored, it cannot receive primary emphasis. This is attributed to the fact that when developing a forecast of future earnings growth, a securities' analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance is already reflected in analysts' forecasts, which reflect an assessment of how the future will diverge from historical performance. Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investor expectations concerning their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments, and are the primary driver of retention growth and its surrogate book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[4] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, represent a reasonable assessment of investor expectations.

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

The forecasts of earnings per share growth, as shown on Attachment PRM- 9 provide a range of growth rates of 5.67% to 6.71%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an

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

investor-expected growth rate of 6.00% is within the array of earnings per share growth rates shown by the analysts' forecasts. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As I previously indicated, the restructuring and consolidation now taking place in the utility industry will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts and will enhance the growth prospects for the future. As such, a 6.00% growth rate will accommodate all these factors.

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

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

Q: Please explain why.

A: If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital with a book value capital structure used for ratesetting purposes, those results will not reflect the higher level of financial risk associated with the book value capital structure. Where, as here, a stock's market price diverges from a utility's book value, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded the Pennsylvania Public Utility Commission to adjust the cost of equity upward to make the return consistent with the book value capital structure in the following cases:

- January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-00016339 -- 60 basis points adjustment.

- August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750 -- 80 basis points adjustment.

- January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis points adjustment.

- August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis points adjustment.

- December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-00049255 -- 45 basis points.

- February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398 -- 70 basis points adjustment.

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

Q: Is your leverage adjustment dependent upon the market valuation or book

valuation from an investor's perspective?

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

Q: Is your leverage adjustment in any way related to a transformation of the return designed to address the market-to-book ratio?

A: No. The adjustment that I label as a "leverage adjustment" is merely a convenient way to incorporate into the result of the simple DCF model (i.e., D/P + g), when applied to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. This is because the equity return applicable to the book value common equity ratio is equal to 9.47%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 1.39% compensation for having a 44.52% debt ratio, plus 0.02% for having a 0.25% preferred stock ratio. The sum of the parts is 10.88% (9.47% + 1.39% + 0.02%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 4.26% dividend yield, the 6.00% growth rate, and the 0.62% for the leverage adjustment in order to arrive at the same 10.88% (4.26% + 6.00% + 0.62%) return. I know of no means to mathematically solve for the 0.62% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.62% adjustment is merely a convenient way to compare the 10.88% return computed directly with the Modigliani & Miller formulas to the 10.26% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

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

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

Further, as noted previously, the high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from its cost of equity. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of February 16, 2009, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.73 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 2.11 times book value, and the Dow Jones Industrial index was at 2.52 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of its cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

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

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

A: The capital structure ratios measured at the utility's book value show more financial leverage, and higher risk, than the capitalization measured at its market value. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different -- in this instance, much lower -- from that shown by the book value capitalization. Hence, it is necessary to develop a cost of equity that reflects the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Gas Group that is related to the 55.24% common equity ratio using book value has higher financial risk than the 68.79% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization. Absent this adjustment, and holding all other variables equal, the utility will not earn an authorized return, which is derived from a stock market prices that reflects the financial risk associated with that price.

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

A: In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases[5]. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value

[5] Modigliani, F. and Miller, M.H. "The Cost of Capital, Corporation Finance, and the Theory of Investments." American Economic Review, June 1958, 261-297.

Modigliani, F. and Miller, M. H. "Taxes and the Cost of Capital: A Correction." American Economic Review, June 1963, 433-443.

capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. Simply stated, the leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. There can be no dispute that a firm's financial risk varies with the relative amount of leverage contained in its capital structure. As detailed in Appendix E, the Modigliani and Miller theory when applied to the Gas Group shows that the cost of equity increases by 0.62% (10.88% - 10.26%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

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

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

	D_1/P_0 +	g	+	$lev.$	=	k	x	$flot.$	=	K
Gas Group	4.26% +	6.00%	+	0.62%	=	10.88%	x	1.02	=	11.10%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.22% (11.10% - 10.88%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. As I noted previously in my testimony, there are factors that add to the Company risk. The DCF results for Columbia of Kentucky would be 11.85% (11.10% + 0.75%) in recognition of its higher risk profile.

RISK PREMIUM ANALYSIS

Q: Please describe your use of the risk premium approach to determine the cost of equity.

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

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

A: In my opinion, a 6.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. The Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Attachment PRM- 11. For the twelve months ended February 2009, the average monthly yield on Moody's A-rated index of public utility bonds was 6.57%. For the six and three-month periods ended February 2009, the yields were 6.81% and 6.40%, respectively. During the twelve-months ended February 2009, the range of the yields on A-rated public utility bonds was 6.21% to 7.60%. During 2008, many critical events have occurred that influence the yields on long-term corporate debt. They include: (i) the collapse of The Bear Stearns Company and its acquisition by JPMorgan Chase & Co. with the aid of the Federal Reserve Bank of New York announced on March 16, 2008; (ii) the failure of IndyMac on July 11, 2008, which was at the time the third-largest banking failure in U.S. history, after a "run on the bank" by depositors;

(iii) the placement of the government-sponsored enterprises ("GSE") Federal National Mortgage Association (Fannie Mae) and Freddie Mac into conservatorship on September 7, 2008 by the Federal Housing Finance Agency; (iv) the largest bankruptcy filing in history by Lehman Brothers Holding, Inc. on September 15, 2008; (v) the acquisition of the banking operations of Washington Mutual, then the largest U.S. savings bank, by JPMorgan Chase on September 24, 2008, (Washington Mutual's holding company subsequently filed for bankruptcy protection); (vi) the rescue of Merrill Lynch & Co., Inc. by Bank of America on September 15, 2008, with assistance of the Federal government; (vii) the effective nationalization on September 23, 2008, of American International Group, then the world's largest insurance company, through the acquisition of 79.9% of its equity by the U.S. Treasury and (viii) other significant events affecting financial markets globally. In response to these events, on October 3, 2008, Congress passed and the President signed the Emergency Economic Stabilization Act of 2008, which, among other provisions, provides the mechanism to deploy up to $700 billion through the Troubled Asset Relief Program ("TARP") to address urgent needs created by the credit crisis the country has experienced. Then, the Federal Reserve Board instituted its Commercial Paper Funding Facility ("CPFF"), which was authorized on October 7, 2008, and it participated in coordinated efforts by major central banks to support financial stability and to maintain flows of credit in the banking system. These programs included a $75 billion Term Auction Facility ("TAF"), a future TAF auction totaling $150 billion, and an increase to $620 billion of swap authorizations with central banks in Canada, England, Japan, Denmark, the European Union, Norway, Australia, Sweden, and Switzerland. Further, on February 17, 2009, the President signed the American Recovery and Reinvestment Act that committed $789 billion by the Federal government in an effort to create jobs, jumpstart growth and to transform the economy in reaction to the recession that began in December 2007.

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

A: I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix G. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on February 1 2009, and a yield spread of 2.50%. As shown on page 5 of Attachment PRM-11, A-rated public utility bonds have yielded more than Treasury bonds by 2.33% as the twelve-month average, 2.89% as the six-month average, and 2.91% as the three-month average. From these averages, 2.50% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts			A-rated Public Utility	
		Corporate		30-Year		
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2009	1st	4.9%	7.9%	3.0%	2.50%	5.50%
2009	2nd	4.9%	7.6%	3.1%	2.50%	5.60%
2009	3rd	5.0%	7.5%	3.2%	2.50%	5.70%
2009	4th	5.1%	7.4%	3.4%	2.50%	5.90%
2010	1st	5.2%	7.4%	3.7%	2.50%	6.20%
2010	2nd	5.4%	7.5%	3.9%	2.50%	6.40%

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

A: Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2008 publication, Blue Chip published forecasts of interest rates are reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2010-14	6.4%	7.6%	5.2%
2015-19	6.6%	7.7%	5.6%

Given these forecasted interest rates, a 6.50% yield on A-rated public utility bonds represents a reasonable expectation.

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

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

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

A: To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Attachment PRM-12, the indicated risk premiums for the various time periods analyzed are 5.51% (1928-2007), 6.58% (1952-2007), 6.08% (1974-2007), and 6.37% (1979-2007). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals, and removes some of the more distant data from the analysis.

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

A: Yes. First, the terminal year of my analysis presented in Attachment PRM-12 represents the returns realized through 2007. Second, the selection of the initial year of each period was based upon the financial market defining events that I note here and described in Appendix H. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. I consistently use these periods in my work, and additional data are merely added to the earlier results when they become available. The periods chosen are therefore not driven by the desired results of the study.

Q: What conclusions have you drawn from these data?

A: Using the summary values provided on page 2 of Attachment PRM-12, the 1928-2007 period provides the lowest indicated risk premium, while the 1952-2007 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 6.23% (6.08% + 6.37% = 12.45% ÷ 2) is shown from data covering the periods 1974-2007 and 1979-2007. Therefore, 6.23% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.50% represents a reasonable common equity risk premium in this case. This represents approximately 88% (5.50% ÷ 6.23% = 0.88) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q: What common equity cost rate did you determine using this risk premium analysis?

A: The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot."). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	6.50%	+	5.50%	=	12.00%	+	0.22%	=	12.22%

As noted previously, the cost of debt for a company with a Baa/BBB rating is higher than an A rating. As such, the cost of equity for Columbia of Kentucky would be 12.97% (12.22% + 0.75%) in recognition of its higher credit quality risk profile.

CAPITAL ASSET PRICING MODEL

Q: Have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

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

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

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

Q: What betas have you considered in the CAPM?

A: For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Attachment PRM-13, the average beta is 0.70 for the Gas Group.

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

A: The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula.[6] This adjustment has been made with the formula:

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

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.54 for the Gas Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of 0.83 for the book value capital structure of the Gas Group. The betas and its corresponding common equity ratios are:

Market Values		Book Values	
Beta	Common Equity Ratio	Beta	Common Equity Ratio
0.70	68.79%	0.83	56.24%

[6] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452

The book value leveraged beta that I will employ in the CAPM cost of equity is 0.83 for the Gas Group.

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

A: For reasons explained in Appendix G, I have employed the yields on 20-year Treasury bonds using historical data. For forecasts, I have used the yields on 30-year Treasury bonds that are published by Blue Chip. The reason that I used the 20-year Treasury yield in my historical analysis relates to the interruption in the 30-year series, which had no data reported for the months of March 2002 to January 2006. That is to say, 48-months of data were missing from the 60-months that used for my five-year historical analysis shown on page 2 of Attachment PRM-13. As shown on pages 2 and 3 of Attachment PRM-12, I provided the historical yields on Treasury notes and bonds. For the twelve months ended February 2009, the average yield was 4.23%, as shown on page 3 of that schedule. For the six- and three-months ended February 2009, the yields on 20-year Treasury bonds were 3.92% and 3.49%, respectively. During the twelve-months ended February 2009, the range of the yields on 20-year Treasury bonds was 3.18% to 4.74%. As shown on page 4 of Attachment PRM-12, forecasts published by Blue Chip on February 1, 2009 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.9% during the next six quarters. The longer term forecasts described previously (see Blue Chip Financial Forecast shown on page 34) show that the yields on Treasury bonds will average 5.2% from 2010 through 2014 and 5.6% for 2015 to 2019. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 4.00% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

Q: What market premium have you used in the CAPM?

A: As developed in Appendix I, the market premium is derived from the SBBI Classic Yearbook (i.e., 6.8%) and the Value Line and S&P 500 returns (i.e., 11.84%). For the historically based market premium, I have used the arithmetic mean. The market premium as taken from these sources provides 9.32% (6.8% + 11.84% = 18.64% ÷ 2).

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

A: Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Gas Group has an average market capitalization of its equity of $1,814 million, which would make them a low-cap portfolio. The low-cap market capitalization would indicate a size premium of 1.65%. However, for my CAPM analysis, I have adopted a mid-cap adjustment of 0.92%, which provides a more conservative representation of the size adjustment because it provides a smaller premium than the low-cap adjustment. Absent such an adjustment, the CAPM would understate the required return.

Q: What CAPM result have you determined using the CAPM?

A: Using the 4.00% risk-free rate of return, the leverage adjusted beta of 0.83 for the Gas Group, the 9.32% market premium, and the size adjustment, and the flotation cost adjustment developed previously the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*	+	*flot.*	=	*K*
Gas Group	4.00%	+	0.83	x (	9.32%	) +	0.92%	=	12.66%	+	0.22%	=	12.88%

For the Company, the CAPM results would be 13.63% (12.88% + 0.75%) in recognition of the Company's higher credit quality risk.

<u>COMPARABLE EARNINGS APPROACH</u>

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

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

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

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

Q: How have you implemented the Comparable Earnings approach?

A: In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Attachment PRM-13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-13, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

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

A: I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because, the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 14.6% using the median value as shown on page 2 of Attachment PRM-13. The forecast rates of return, as published by Value Line are shown by the 12.8% median values also provided on page 2 of Attachment PRM-13.

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

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

	Historical	*Forecast*	*Average*
Comparable Earnings Group	14.60%	12.8%	13.70%

As noted previously, I have used the results from the Comparable Earnings method to confirm the results of the market based models.

CONCLUSION ON COST OF EQUITY

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

A: Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is 12.25% for the Company. My cost of equity recommendation should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets.

It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q: Does this conclude your direct testimony at this time?

A: Yes, it does; however I reserve the right to file rebuttal testimony if necessary.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

APPENDICES A THROUGH J TO ACCOMPANY THE PREPARED DIRECT TESTIMONY OF PAUL R. MOUL ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

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

My studies and prepared direct testimony have been presented before thirty-five (35) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

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

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

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

My lecture and speaking engagements include:

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

May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commis-sion and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

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

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

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

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

to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

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

EVALUATION OF RISK

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

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

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc.

that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

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

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

APPENDIX D TO DIRECT TESTIMONY OF PAUL R. MOUL

COST OF EQUITY--GENERAL APPROACH

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

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

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

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

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

APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

DISCOUNTED CASH FLOW ANALYSIS

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

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

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

$$P0 = \frac{D1}{(1+Kp)} + \frac{D2}{(1+Kp)^2} + \frac{D3}{(1+Kp)^3} + \ldots + \frac{Dn}{(1+Kp)^n}$$

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

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

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

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in

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

all modern basic finance textbooks. This DCF equation can be easily solved as:

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

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

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

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the

---

earlier.

near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price (P_0) of \$10.00, a dividend (D_0) of \$0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Attachment PRM-3. The 2003-2007 five-year average dividend yield was 3.9% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Attachment PRM-7. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

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

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

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

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

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 3.000% (6.00% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.25% (4.13% x 1.03000) for the Gas Group.

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

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

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.28% (4.13% x

1.03723) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)*, results in a third DCF formulation:

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

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

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

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 1.0325% (4.13% ÷ 4) for the gas Group. The compound dividend yield would be 4.26% (1.010474^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 4.26% forward-looking dividend yield is the average (4.25% + 4.28% + 4.26% = 12.79% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

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

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

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

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

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. In 2008, Thomson acquired Reuters, which formerly published the Market Guide forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Another service that tabulates earnings forecasts and publishes them are Zacks Investment Research. As with the IBES/First Call forecasts and Zacks provides consensus forecasts collected from analysts for most publically traded companies.

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

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

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

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

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial

Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

Gas Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	31.05%	44.52%
Preferred Stock	0.16	0.25
Common Equity	68.79	55.24
Total	100.00%	100.00%

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

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

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

$$9.47\% = 10.26\% - (((9.47\%-6.81\%)\ .65)\ 31.05\%/68.79\%) - (9.47\% - 6.04\%)\ 0.16\%/68.79\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt[3], d = dividend rate on preferred stock[4], D = debt ratio, P = preferred stock ratio, and E

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

= common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 9.47% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 9.47% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

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

$$10.88\% = 9.47\% + (((9.47\%-6.81\%).65)\ 44.52\%/55.24\%) + (9.47\%-6.04\%)\ 0.25\%/55.24$$

---

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

APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

FLOTATION COST ADJUSTMENT

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

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period.

An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

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

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Attachment PRM-10. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 4.0% for public offerings of common stocks by gas companies from 2003 to 2007. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

INTEREST RATES

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

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

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes, which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

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

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

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

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

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

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because

Treasury securities encompass a very large market, which provides ease of trading, and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

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

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

FOMC reduced the Fed Funds rate to 4.75%.

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

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

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

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

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

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

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

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

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

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

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

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

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) concerns regarding the Federal budget deficit. All these factors significantly changed the sentiment in the bond market.

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

Just after the FOMC meeting on August 7, 2007, where the FOMC decided to retain a 5.25% Fed Funds rate, turmoil in the credit markets prompted central banks throughout the world to inject over $325 billion of reserves into the banking system over a three-day period in reaction to a credit crunch. Problems had been developing earlier in 2007, beginning in the market for asset-backed securities linked to subprime mortgages. Valuation uncertainties for these securities caused liquidity concerns for hedge funds, investment banks, and financial institutions. The market for commercial paper, the most liquid part of the credit markets for non-Treasury securities, was also affected. In response to the market turmoil, the FOMC issued the following statement, the first of its type since after the September 11, 2001 terrorists' attack.

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

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

> Financial market conditions have deteriorated, and tighter credit conditions and increased uncertainty have the potential to restrain economic growth going forward. In these

> circumstances, although recent data suggest that the economy has continued to expand at a moderate pace, the Federal Open Market Committee judges that the downside risks to growth have increased appreciably. The Committee is monitoring the situation and is prepared to act as needed to mitigate the adverse effects on the economy arising from the disruptions in financial markets.

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

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

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

In 2008, the FOMC again acted decisively in response to further deterioration of credit conditions and perceived weakness in the economy. Acting prior to its first regularly scheduled meeting in 2008, on January 22, 2008, the FOMC reduced the fed funds target by 75 basis points to 3.50% and the discount rate was reduced by a corresponding amount to 4.00%. Actions by the FOMC between meetings are unusual occurrences in recent years, thereby signifying the urgency that the FOMC saw in taking immediate action on monetary policy. Then on January 30, 2008, the fed funds target rate and discount rate were further reduced by 50 basis points, bringing those rates to 3.00% and 3.50%, respectively. Credit market turmoil continued, and after the collapse of a major investment bank (The Bear Stearn Companies), the FOMC stated:

> The Federal Reserve on Sunday announced two initiatives designed to bolster market liquidity and promote orderly market functioning. Liquid, well-functioning markets are essential for the promotion of economic growth.
>
> First, the Federal Reserve Board voted unanimously to authorize the Federal Reserve Bank of New York to create a lending facility to improve the ability of primary dealers to provide financing to participants in securitization markets. This facility will be available for business on Monday, March 17. It will be in place for at least six months and may be extended as conditions warrant. Credit extended to primary dealers under this facility may be collateralized by a broad range of investment-grade debt securities. The interest rate charged on such credit will be the same as the primary credit rate, or discount rate, at the Federal Reserve Bank of New York.
>
> Second, the Federal Reserve Board unanimously approved a request by the Federal Reserve Bank of New York to decrease the primary credit rate from 3-1/2 percent to 3-1/4 percent, effective immediately. This step lowers the spread of the primary credit rate over the Federal Open Market Committee's target federal funds rate to 1/4 percentage point. The Board also approved an increase in the maximum maturity of primary credit loans to 90 days from 30 days.
>
> The Board also approved the financing arrangement announced by JPMorgan Chase & Co. and The Bear Stearns Companies

Inc.

Then on March 18, 2008, the FOMC reduced the fed funds rate to 2.25% and the discount rate to 2.50%. Afterward on April 30, 2008, the FOMC further reduces the fed funds rate to 2.00% and the discount rate to 2.25%. At subsequent meetings the FOMC held the fed funds rate steady. Then on October 8, 2008, the FOMC took another unusual unscheduled action by reducing the Fed Funds rate to 1.50% and the discount rate to 1.75%. Then, on October 29, the FOMC lowered the Fed Funds rate to 1.00% and the discount rate to 1.25%. As 2008 neared its end, the FOMC lowered the Fed Funds rate to a target range of 0.00% to 0.25%, its lowest rate ever. The FOMC maintained its target range of 0.00% to 0.25% in early 2009. At its meeting on January 28, 2009, the FOMC stated:

> Information received since the Committee met in December suggests that the economy has weakened further. Industrial production, housing starts, and employment have continued to decline steeply, as consumers and businesses have cut back spending. Furthermore, global demand appears to be slowing significantly. Conditions in some financial markets have improved, in part reflecting government efforts to provide liquidity and strengthen financial institutions; nevertheless, credit conditions for households and firms remain extremely tight. The Committee anticipates that a gradual recovery in economic activity will begin later this year, but the downside risks to that outlook are significant.
>
> In light of the declines in the prices of energy and other commodities in recent months and the prospects for considerable economic slack, the Committee expects that inflation pressures will remain subdued in coming quarters. Moreover, the Committee sees some risk that inflation could persist for a time below rates that best foster economic growth and price stability in the longer term.
>
> The Federal Reserve will employ all available tools to promote the resumption of sustainable economic growth and to preserve price stability. The focus of the Committee's policy is to support the functioning of financial markets and stimulate the economy through open market operations and other measures

> that are likely to keep the size of the Federal Reserve's balance sheet at a high level. The Federal Reserve continues to purchase large quantities of agency debt and mortgage-backed securities to provide support to the mortgage and housing markets, and it stands ready to expand the quantity of such purchases and the duration of the purchase program as conditions warrant. The Committee also is prepared to purchase longer-term Treasury securities if evolving circumstances indicate that such transactions would be particularly effective in improving conditions in private credit markets. The Federal Reserve will be implementing the Term Asset-Backed Securities Loan Facility to facilitate the extension of credit to households and small businesses. The Committee will continue to monitor carefully the size and composition of the Federal Reserve's balance sheet in light of evolving financial market developments and to assess whether expansions of or modifications to lending facilities would serve to further support credit markets and economic activity and help to preserve price stability.

Public Utility Bond Yields

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

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

Pages 1 and 2 of Attachment PRM-10 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds, which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Attachment PRM-10. There, it is shown that those spreads were about one percent during the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to the run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Attachment PRM-10, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds was about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005, 1.08% in 2006, 1.16% in 2007, and 2.17% in 2008.

As shown by the monthly data presented on pages 4 and 5 of Attachment PRM-10, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 2.33% percentage points for the twelve-months ended February 2009. For the six- and three-month periods ending February 2009, the yield spread was 2.89% and 2.91%, respectively.

Beginning in August 2007, spreads widened significantly with the development of the credit crunch. As the credit crisis developed, there was a flight to quality, thereby increasing demand and reducing the yields on Treasury obligations. While this situation is most pronounced at the shortest end of the yield curve (i.e., obligations with the shortest duration), all Treasury yields display relatively low yields by reference to other credit obligations. By the fourth quarter of 2008, the spread in yields on A-rated public utility bonds and 20-year Treasury bonds tripled since the onset of the credit crisis. These spreads are symptomatic of risk aversion by investors throughout the capital markets. That is to say, the risk aversion of investors in both debt and equity markets has translated into higher capital costs for both bonds and stocks.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix I), pages 2 and 3 of Attachment PRM-12 provides the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary

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

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

RISK PREMIUM ANALYSIS

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

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

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

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

$$k=i+RP$$

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

Equity Risk Premium

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

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

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

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

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

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

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix I, the long-term cost of capital in rate cases requires the use of arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. While the use of the geometric mean would be inappropriate for CAPM purposes due to the specification of that model, it can provide a limit of the bounds for the Risk Premium approach that does not contain the single-period limitation. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2007, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.82%	5.52%
Geometric Mean	4.23%	3.47%
Median	9.27%	7.50%
Midpoint of Range	6.75%	5.49%
Average of Arithmetic Mean and Midpoint of Range	6.29%	5.51%

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

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Attachment PRM-12 should also be considered. One of these sub-periods included the 56-year period, 1952-2007. These years follow the historic 1951 Treasury-Federal Reserve Accord, which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2007 and 1979 through 2007 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 56-year, 34-year and 29-year periods, the public utility risk premiums were 6.58%, 6.08%, and 6.37% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Attachment PRM-12.

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

CAPITAL ASSET PRICING MODEL

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

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

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

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

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

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

Beta

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

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

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

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return

("Rm - Rf"). In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line and the S&P 500 data series using dividend yields and capital appreciation (i.e., capital gains yield).

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the September 12, 2008 edition of The Value Line Investment Survey Summary and Index, (see page 5 of Attachment PRM-13) the total return on the Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of September 12, 2008	2.2%	+	15.02%[1]	=	17.22%

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

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
4.52%	(	1.0486	)	+	9.71%	=	14.45%

where:	Price (P)	at	28-Feb-2009	=	735.09
	Dividend (D)	for	1st Qtr. '09	=	8.31
	Dividend (D)		annualized	=	33.24
	Growth (g)		First Call EpS	=	9.71%

Using these indicators, the total market return is 15.84% (17.22% + 14.45% = 31.67% ÷ 2) using both the Value Line and S&P 500 derived returns. With the 15.84% forecast market

[1]The estimated median appreciation potential is forecast to be 75% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 15.02% (i.e., $1.75^{.25}$ - 1).

return and the 4.00% risk-free rate of return, a 11.84% (15.84% - 4.00%) market premium would be indicated using these data.

I have also provided market premiums that have been widely circulated among the investment and academic community, which today is published by Morningstar, Inc. These data are contained in the 2008 Ibbotson® Stocks, Bonds, Bills and Inflation ("SBBI") Classic Yearbook. From the data provided on page 6 of Attachment PRM-13, I calculate a market premium using the historical common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2007, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

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

> return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

Also shown on page 6 of Attachment PRM-13 is the long-horizon expected market premiums of 7.1% also published in the SBBI Classic Yearbook. An average of the historical and expected SBBI market premium is 6.8% (6.5% + 7.1% = 13.6% ÷ 2).

For the CAPM, a market premium of 9.32% (6.8% + 11.84% = 18.64% ÷ 2) would be reasonable, which is the average of the 6.8% SBBI data and the 11.84% Value Line and S&P 500 data.

COMPARABLE EARNINGS APPROACH

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

Timeliness Rank

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

Safety Rank

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

Financial Strength

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

Price Stability Index

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

Beta

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

Technical Rank

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

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia	)	
Gas of Kentucky, Inc.	)	Case No. 2009-00141

ATTACHMENTS TO ACCOMPANY THE TESTIMONY OF PAUL R. MOUL ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

Columbia Gas of Kentucky, Inc.
Index of Attachments

Columbia Gas of Kentucky, Inc.

Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.56%	5.76%	2.45%
Short-Term Debt	5.42%	3.24%	0.18%
Total Debt	47.98%		2.63%
Common Equity	52.02%	12.25%	6.37%
Total	100.00%		9.00%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 35.0000% income tax rate (12.43% ÷ 2.63%)	4.73 x
Post-tax coverage of interest expense (9.00% ÷ 2.63%)	3.42 x

Columbia Gas of Kentucky, Inc.
Capitalization and Financial Statistics
2004-2008, Inclusive

	2008	2007	2006	2005	2004	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 167.5	$ 159.9	$ 148.1	$ 117.8	$ 119.6	
Short-Term Debt	$ -	$ -	$ -	$ -	$ -	
Total Capital	$ 167.5	$ 159.9	$ 148.1	$ 117.8	$ 119.6	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	43.0%	36.3%	39.2%	30.8%	35.2%	36.9%
Common Equity (1)	57.0%	63.7%	60.8%	69.2%	64.8%	63.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	43.0%	36.3%	39.2%	30.8%	35.2%	36.9%
Common Equity (1)	57.0%	63.7%	60.8%	69.2%	64.8%	63.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	10.6%	12.1%	9.9%	10.0%	10.6%	10.6%
Operating Ratio (2)	91.7%	89.2%	92.5%	92.0%	90.0%	91.1%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	5.52 x	6.22 x	5.52 x	4.34 x	4.86 x	5.29 x
Post-tax: All Interest Charges	3.78 x	4.30 x	3.88 x	3.12 x	3.39 x	3.69 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	5.51 x	6.20 x	5.44 x	4.33 x	4.84 x	5.26 x
Post-tax: All Interest Charges	3.77 x	4.29 x	3.79 x	3.11 x	3.37 x	3.67 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.3%	0.5%	3.1%	0.3%	0.8%	1.0%
Effective Income Tax Rate	38.5%	36.7%	36.4%	36.6%	38.1%	37.3%
Internal Cash Generation/Construction (4)	37.1%	226.0%	107.4%	100.0%	2.8%	94.7%
Gross Cash Flow/ Avg. Total Debt (5)	34.2%	38.7%	20.0%	38.2%	21.9%	30.6%
Gross Cash Flow Interest Coverage (6)	6.91 x	7.41 x	4.11 x	4.98 x	3.69 x	5.42 x

See Page 2 for Notes.

Columbia Gas of Kentucky, Inc.
Capitalization and Financial Statistics
2004-2008, Inclusive

Notes:

(1) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(3) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(4) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(5) Gross Cash Flow plus interest charges divided by interest charges.

(6) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: FERC Form No. 2

Gas Group
Capitalization and Financial Statistics [1]
2003-2007, Inclusive

	2007	2006	2005	2004	2003	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,979.7	$ 1,900.4	$ 1,823.5	$ 1,530.7	$ 1,233.7	
Short-Term Debt	$ 232.6	$ 263.5	$ 187.8	$ 141.9	$ 218.6	
Total Capital	$ 2,212.3	$ 2,163.9	$ 2,011.3	$ 1,672.6	$ 1,452.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	16 x	16 x	15 x	14 x	16 x
Market/Book Ratio	195.4%	192.9%	198.4%	187.4%	180.9%	191.0%
Dividend Yield	3.7%	3.7%	3.7%	4.0%	4.5%	3.9%
Dividend Payout Ratio	60.2%	59.4%	59.6%	61.4%	61.5%	60.4%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	44.9%	46.4%	46.1%	45.7%	46.7%	45.9%
Preferred Stock	0.5%	0.5%	0.4%	0.5%	0.3%	0.4%
Common Equity [2]	54.6%	53.2%	53.5%	53.8%	53.0%	53.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	51.5%	53.8%	51.9%	50.9%	55.2%	52.6%
Preferred Stock	0.4%	0.4%	0.4%	0.4%	0.3%	0.4%
Common Equity [2]	48.1%	45.8%	47.7%	48.7%	44.5%	47.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	11.7%	12.4%	12.2%	12.1%	13.0%	12.3%
Operating Ratio [3]	88.7%	89.1%	89.1%	88.1%	86.7%	88.3%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.07 x	4.14 x	4.43 x	4.61 x	4.44 x	4.34 x
Post-tax: All Interest Charges	2.89 x	2.92 x	3.11 x	3.22 x	3.11 x	3.05 x
Overall Coverage: All Int. & Pfd. Div.	2.88 x	2.91 x	3.10 x	3.21 x	3.10 x	3.04 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.04 x	4.11 x	4.41 x	4.59 x	4.42 x	4.31 x
Post-tax: All Interest Charges	2.86 x	2.89 x	3.10 x	3.20 x	3.09 x	3.03 x
Overall Coverage: All Int. & Pfd. Div.	2.85 x	2.88 x	3.08 x	3.19 x	3.08 x	3.02 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	1.9%	1.8%	0.9%	1.2%	1.2%	1.4%
Effective Income Tax Rate	38.2%	38.5%	38.1%	38.0%	38.1%	38.2%
Internal Cash Generation/Construction [5]	110.5%	78.0%	84.6%	94.4%	120.4%	97.6%
Gross Cash Flow/ Avg. Total Debt [6]	21.1%	18.9%	20.3%	22.0%	22.6%	21.0%
Gross Cash Flow Interest Coverage [7]	4.80 x	4.15 x	4.53 x	5.28 x	5.32 x	4.82 x
Common Dividend Coverage [8]	3.41 x	3.10 x	3.06 x	3.50 x	3.71 x	3.36 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2003-2007, Inclusive

Notes:

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

Basis of Selection:

The Gas Group includes companies that are contained in The Value Line Investment Survey basic service, and the elimination of five companies, which were Laclede and Nicor because they lack a decoupling feature in their tariffs, NiSource due to its electric operations and its natural gas pipeline and storage operations, Southwest Gas due to its location, and UGI Corporation because of its highly diversified businesses.

Ticker	Company	Corporate Credit Ratings Moody's	S&P	Stock Traded	S&P Stock Ranking	Value Line Beta
ATG	AGL Resources, Inc.	A3	A-	NYSE	A	0.75
ATO	Atmos Energy Corp.	Baa3	BBB+	NYSE	A-	0.65
NJR	New Jersey Resources Corp	Aa3	A	NYSE	A	0.70
NWN	Northwest Natural Gas	A3	AA-	NYSE	A-	0.60
PNY	Piedmont Natural Gas Co.	A3	A	NYSE	A	0.70
SJI	South Jersey Industries, Inc.	A3	BBB+	NYSE	A-	0.75
WGL	WGL Holdings, Inc.	A2	AA-	NYSE	B+	0.75
	Average	A3	A		A-	0.70

Note: Ratings are those of utility subsidiaries

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

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
2003-2007, Inclusive

	2007	2006	2005	2004	2003	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 15,126.8	$ 15,219.8	$ 14,312.2	$ 14,207.4	$ 14,016.5	
Short-Term Debt	$ 593.1	$ 491.9	$ 452.6	$ 261.7	$ 274.0	
Total Capital	$ 15,719.9	$ 15,711.7	$ 14,764.8	$ 14,469.1	$ 14,290.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	16 x	16 x	16 x	15 x	14 x	15 x
Market/Book Ratio	223.3%	205.9%	201.0%	170.4%	149.8%	190.1%
Dividend Yield	3.3%	3.5%	3.6%	3.8%	4.2%	3.7%
Dividend Payout Ratio	53.9%	57.8%	57.0%	58.4%	63.9%	58.2%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.1%	53.4%	54.7%	56.5%	59.2%	55.2%
Preferred Stock	1.2%	1.2%	1.3%	1.5%	1.4%	1.3%
Common Equity (2)	46.8%	45.5%	44.0%	42.0%	39.4%	43.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.4%	55.3%	56.8%	58.1%	60.6%	57.0%
Preferred Stock	1.1%	1.2%	1.3%	1.5%	1.4%	1.3%
Common Equity (2)	44.5%	43.5%	42.0%	40.5%	38.0%	41.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (2)	13.2%	12.2%	11.4%	11.5%	9.6%	11.6%
Operating Ratio (3)	81.9%	84.5%	85.8%	84.6%	85.0%	84.4%
Coverage incl. AFUDC (4)						
Pre-tax: All Interest Charges	3.75 x	3.32 x	3.16 x	3.03 x	2.52 x	3.16 x
Post-tax: All Interest Charges	2.84 x	2.57 x	2.51 x	2.43 x	2.09 x	2.49 x
Overall Coverage: All Int. & Pfd. Div.	2.80 x	2.53 x	2.47 x	2.39 x	2.05 x	2.45 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	3.68 x	3.28 x	3.12 x	3.00 x	2.48 x	3.11 x
Post-tax: All Interest Charges	2.77 x	2.53 x	2.47 x	2.40 x	2.05 x	2.44 x
Overall Coverage: All Int. & Pfd. Div.	2.74 x	2.49 x	2.43 x	2.36 x	2.01 x	2.41 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	4.0%	2.5%	1.0%	2.3%	1.9%	2.3%
Effective Income Tax Rate	34.1%	32.7%	31.6%	26.1%	40.6%	33.0%
Internal Cash Generation/Construction (5)	85.8%	92.9%	102.9%	124.2%	126.5%	106.5%
Gross Cash Flow/ Avg. Total Debt (6)	24.8%	23.1%	20.9%	20.9%	20.8%	22.1%
Gross Cash Flow Interest Coverage (7)	4.92 x	4.47 x	4.34 x	4.37 x	4.40 x	4.50 x
Common Dividend Coverage (8)	5.93 x	4.39 x	4.36 x	4.67 x	5.03 x	4.88 x

See Page 2 for Notes.

<u>Standard & Poor's Public Utilities</u>
Capitalization and Financial Statistics
<u>2003-2007, Inclusive</u>

Notes:

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

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities [1]

	Ticker	Credit Rating [2] Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Baa3	BBB-	NYSE	B	1.10
Ameren Corporation	AEE	Baa2	BBB-	NYSE	A-	0.80
American Electric Power	AEP	Baa2	BBB	NYSE	B	0.85
CMS Energy	CMS	Baa2	BBB-	NYSE	C	0.95
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.90
Consolidated Edison	ED	A1	A-	NYSE	B+	0.65
Constellation Energy Group	CEG	Baa2	BBB	NYSE	B+	0.75
DTE Energy Co.	DTE	Baa1	BBB	NYSE	B	0.75
Dominion Resources	D	Baa1	A-	NYSE	B+	0.70
Duke Energy	DUK	A3	A-	NYSE	B	0.60
Edison Int'l	EIX	A3	BBB+	NYSE	B	0.85
Entergy Corp.	ETR	Baa2	BBB	NYSE	A-	0.80
Exelon Corp.	EXC	A3	BBB	NYSE	B+	0.90
FPL Group	FPL	A1	A	NYSE	A-	0.80
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	A-	0.85
Integrys Energy Group	TEG	A1	A-	NYSE	A-	0.80
NICOR Inc.	GAS	A2	AA	NYSE	B	0.70
NiSource Inc.	NI	Baa2	BBB-	NYSE	B	0.75
PEPCO Holdings, Inc.	POM	Baa2	BBB	NYSE	B	0.75
PG&E Corp.	PCG	A3	BBB+	NYSE	B	0.85
PPL Corp.	PPL	Baa1	A-	NYSE	B+	0.80
Pinnacle West Capital	PNW	Baa2	BBB-	NYSE	B+	0.75
Progress Energy, Inc.	PGN	A3	BBB+	NYSE	B	0.60
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.85
Questar Corp.	STR	A3	A-	NYSE	A	1.25
Sempra Energy	SRE	A2	A	NYSE	B+	0.90
Southern Co.	SO	A2	A	NYSE	A-	0.55
TECO Energy	TE	Baa2	BBB-	NYSE	B	0.75
Xcel Energy Inc	XEL	A3	BBB+	NYSE	B	0.75
Average for S&P Utilities		Baa1	BBB+		B+	0.80

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

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

Columbia Gas of Kentucky, Inc.
Investor-provided Capitalization
Actual and Hypothetical at December 31, 2008

	Actual		Hypothetical	
	Amount Outstanding	Ratios	Amount Outstanding ($000's)	Ratios
Long Term Debt	$ 72,055,000	40.63%	$ 77,368,041 (2)	42.56%
Common Stock Equity				
Common Stock	23,806,202			
Additional Paid in Capital	5,267,487			
Retained Earnings	66,345,621			
Total Common Equity	95,419,310	53.81%	94,560,940 (2)	52.02%
Total Permanent Capital	167,474,310	94.44%	171,928,981	94.58%
Short Term Debt (1)	9,861,432	5.56%	9,861,432	5.42%
Total Capital Employed	$ 177,335,742	100.00%	$ 181,790,413	100.00%

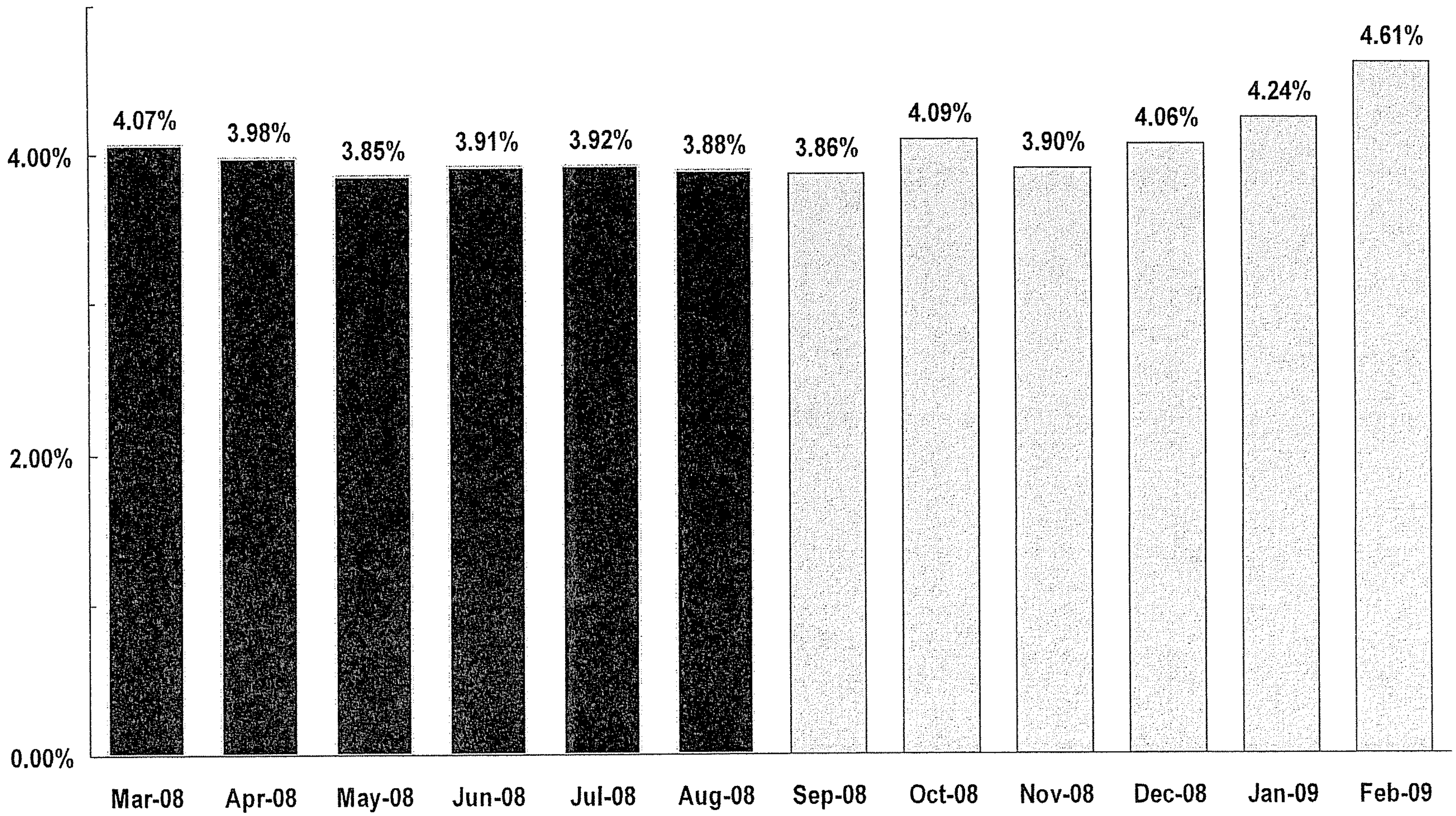
Notes:
(1) Thirteen month average
(2) Reflects hypothetical capitalization using 45% long-term debt and 55% common equity

Source of information: Company provided data

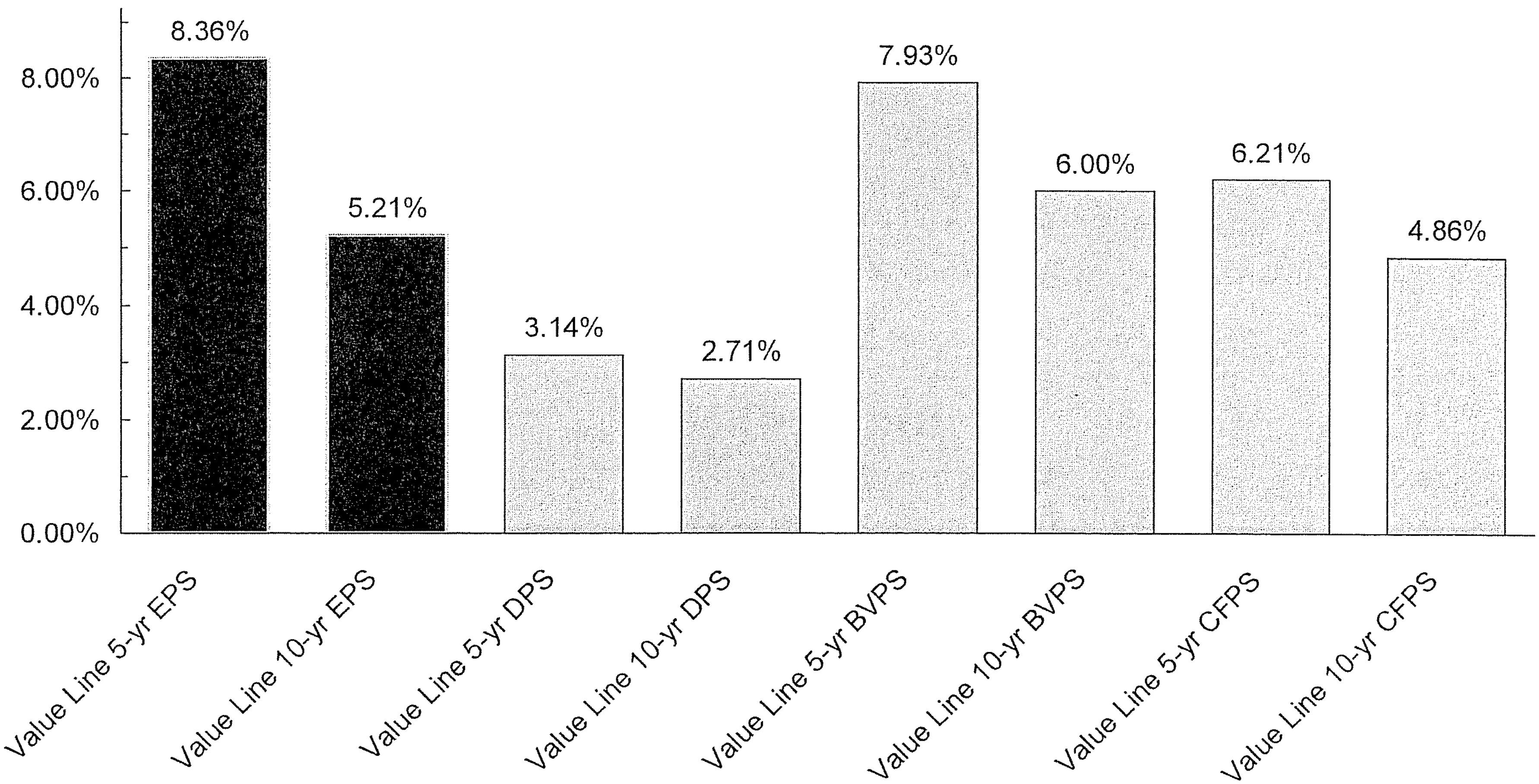
Columbia Gas of Kentucky, Inc.
Long-term Debt Outstanding
Actual and Hypothetical at December 31, 2008

Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
January 7, 2013	5.28%	$ 14,720,000	$ 777,216	
December 23, 2013	5.53%	14,000,000	774,200	
January 5, 2016	5.41%	10,750,000	581,575	
January 5, 2017	5.45%	4,210,000	229,445	
November 1, 2021	6.015%	16,000,000	962,400	
January 5, 2026	5.92%	12,375,000	732,600	
Actual Long-Term Debt		72,055,000	4,057,436	5.63%
Additional Debt	7.44%	5,313,041	395,290	
Hypothetical Long-Term Debt		$ 77,368,041	$ 4,452,726	5.76%

Gas Group
Monthly Dividend Yield

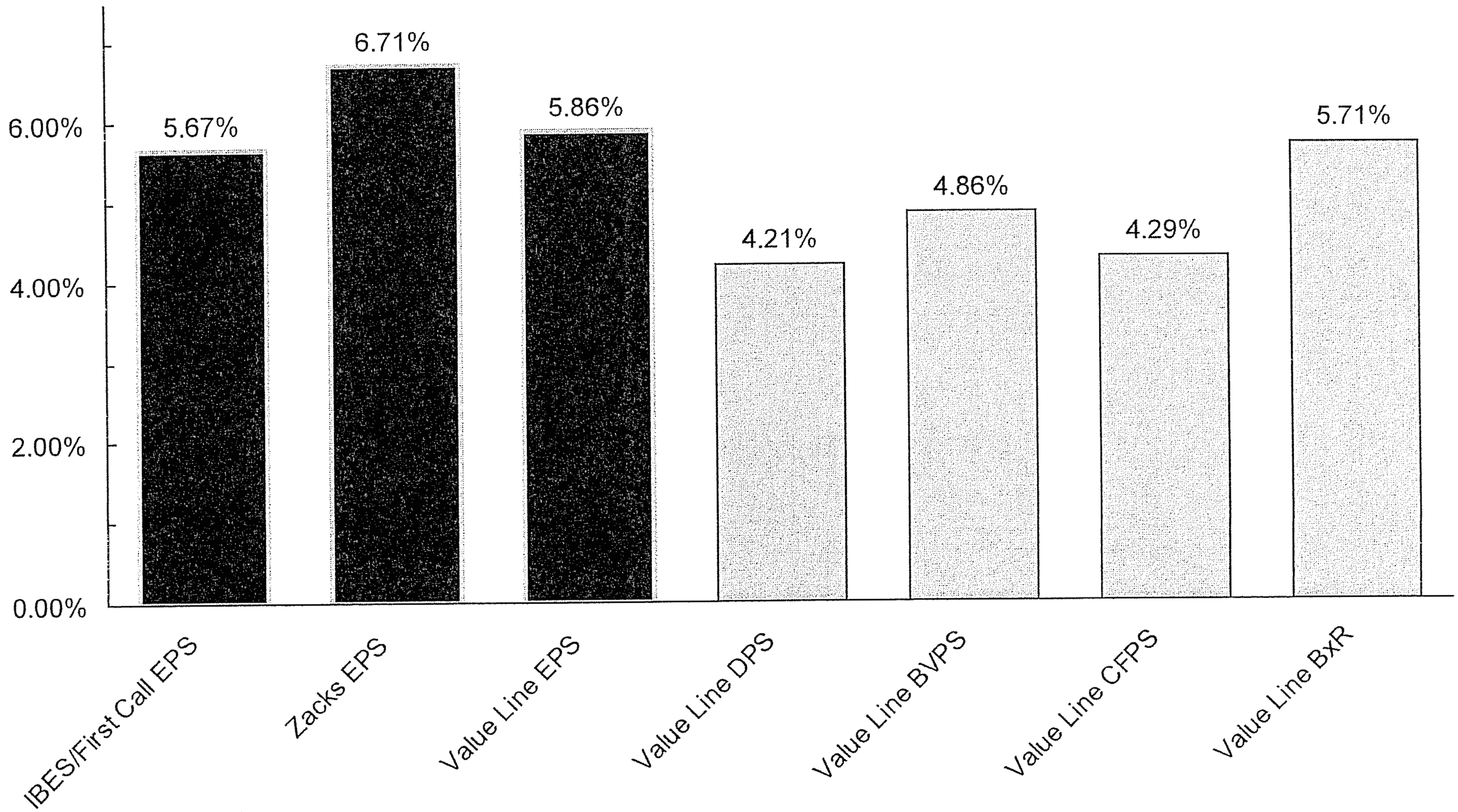


Gas Group
Historical Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS

Gas Group
Five-Year Projected Growth Rates



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

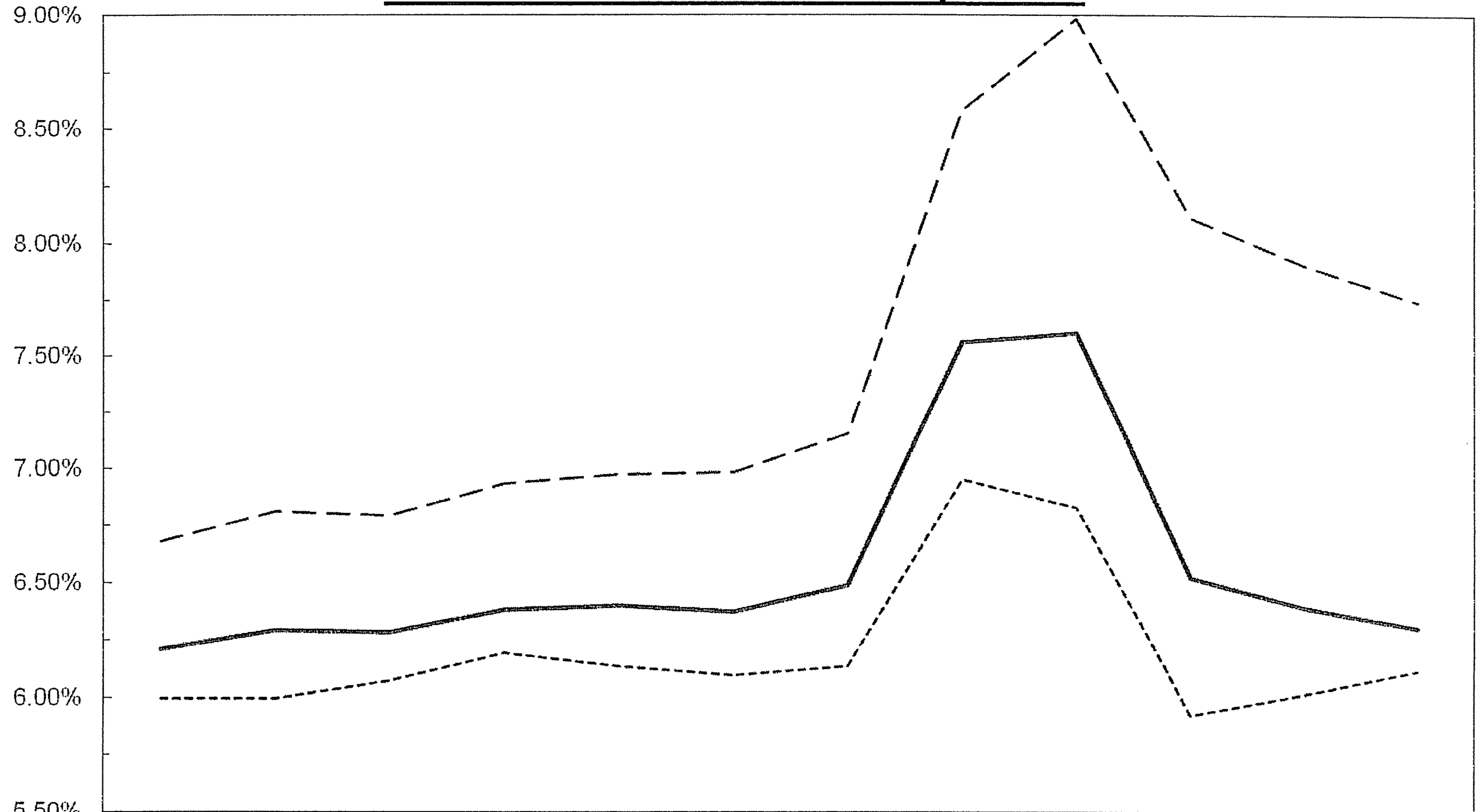
Natural Gas Industry
Analysis of Public Offerings of Common Stock
Years 2003-2007

	AGL RESOURCES	SOUTHERN UNION CO.	ATMOS ENERGY	VECTREN CORP.	SEMPRA ENERGY	PIEDMONT NATURAL	UGI CORP.	NORTHWEST NATURAL	LACLEDE GROUP
Date of Offering	2/11/2003	6/5/2003	6/18/2003	8/7/2003	10/8/2003	1/20/2004	3/18/2004	3/30/2004	5/6/2004
No. of shares offered (000)	5,600	9,500	4,000	6,500	15,000	4,250	7,500	1,200	1,500
Dollar amt. of offering ($000)	$ 123,200	$ 152,000	$ 101,240	$ 148,265	$ 420,000	$ 180.625	$ 240.750	$ 37,200	$ 40,200
Price to public	$ 22 000	$ 16 000	$ 25 310	$ 22 810	$ 28 000	$ 42 500	$ 32 100	$ 31 000	$ 26 800
Underwriter's discounts and commission	$ 0.770	$ 0.560	$ 1.013	$ 0.798	$ 0.840	$ 1.490	$ 1.404	$ 1.010	$ 0.871
Gross Proceeds	$ 21 230	$ 15 440	$ 24 297	$ 22 012	$ 27 160	$ 41.010	$ 30.696	$ 29 990	$ 25.929
Estimated company issuance expenses	$ 0.045	$ 0.089	$ 0.095	$ 0.046	$ 0.033	NA	$ 0.020	$ 0.146	$ 0.067
Net proceeds to company per share	$ 21.185	$ 15.351	$ 24.202	$ 21.966	$ 27.127	$ 41.010	$ 30.676	$ 29.844	$ 25.862
Underwriter's discount as a percent of offering price	3.5%	3.5%	4.0%	3.5%	3.0%	3.5%	4.4%	3.3%	3.3%
Issuance expense as a percent of offering price	0.2%	0.6%	0.4%	0.2%	0.1%	NA	0.1%	0.5%	0.3%
Total Issuance and selling expense as as a percent of offering price	3.7%	4.1%	4.4%	3.7%	3.1%	3.5%	4.5%	3.8%	3.6%

	SOUTHERN UNION CO.	AQUILA	ATMOS ENERGY	AGL RESOURCES	SOUTHERN UNION CO.	SEMCO Energy	Chesapeake Utilities	Vectren	Average
Date of Offering	7/26/2004	8/18/2004	10/21/2004	11/19/2004	2/7/2005	8/9/2005	11/15/2006	2/22/2007	
No. of shares offered (000)	11.000	40,000	14,000	9,600	14,913	4,300	600 3	4,600	
Dollar amt of offering ($000)	$ 206.250	$ 102.000	$ 346.500	$ 297,696	$ 342,999	$ 27,176	$ 18,069	$ 130,318	
Price to public	$ 18.750	$ 2.550	$ 24.750	$ 31.010	$ 23.000	$ 6.320	$ 30.100	$ 28.330	
Underwriter's discounts and commission	$ 0.656	$ 0.099	$ 0.990	$ 0.930	$ 0.700	$ 0.253	$ 1.125	$ 0.990	
Gross Proceeds	$ 18.094	$ 2.451	$ 23.760	$ 30.080	$ 22.300	$ 6.067	$ 28.975	$ 27.340	
Estimated company issuance expenses	$ 0.091	NA	NA	$ 0.042	$ 0.067	$ 0.070	$ 0.375	$ 0.092	
Net proceeds to company per share	$ 18.003	$ 2.451	$ 23.760	$ 30.038	$ 22.233	$ 5.997	$ 28.600	$ 27.248	
Underwriter's discount as a percent of offering price	3.5%	3.9%	4.0%	3.0%	3.0%	4.0%	3.7%	3.5%	3.6%
Issuance expense as a percent of offering price	0.5%	NA	NA	0.1%	0.3%	1.1%	1.2%	0.3%	0.4%
Total Issuance and selling expense as as a percent of offering price	4.0%	3.9%	4.0%	3.1%	3.3%	5.1%	4.9%	3.8%	4.0%

Source of Information: Public Utility Financial Tracker

Interest Rates for Investment Grade Public Utility Bonds



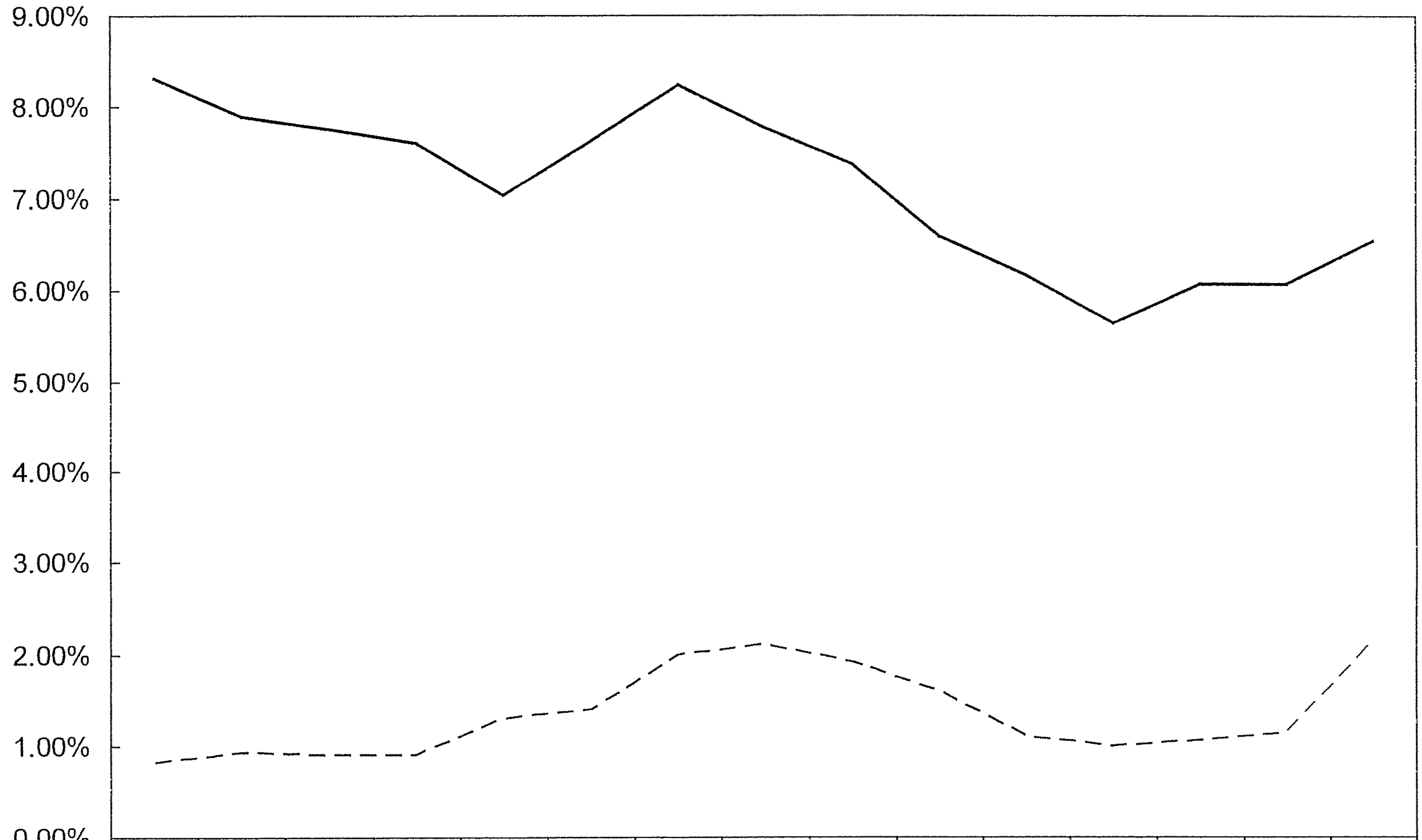
	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
Aa	5.99%	5.99%	6.07%	6.19%	6.13%	6.09%	6.13%	6.95%	6.83%	5.92%	6.01%	6.11%
A	6.21%	6.29%	6.28%	6.38%	6.40%	6.37%	6.49%	7.56%	7.60%	6.52%	6.39%	6.30%
Baa	6.68%	6.81%	6.79%	6.93%	6.97%	6.98%	7.15%	8.58%	8.98%	8.11%	7.90%	7.74%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2003-2007 and 2008
and the Twelve Months Ended February 2009

Years	Aa Rated	A Rated	Baa Rated	Average
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
2005	5.44%	5.65%	5.93%	5.67%
2006	5.84%	6.07%	6.32%	6.08%
2007	5.94%	6.07%	6.33%	6.11%
Five-Year Average	5.93%	6.11%	6.36%	6.13%
2008	6.18%	6.53%	7.24%	6.65%
Months				
Mar-08	5.99%	6.21%	6.68%	6.29%
Apr-08	5.99%	6.29%	6.81%	6.36%
May-08	6.07%	6.28%	6.79%	6.38%
Jun-08	6.19%	6.38%	6.93%	6.50%
Jul-08	6.13%	6.40%	6.97%	6.50%
Aug-08	6.09%	6.37%	6.98%	6.48%
Sep-08	6.13%	6.49%	7.15%	6.59%
Oct-08	6.95%	7.56%	8.58%	7.70%
Nov-08	6.83%	7.60%	8.98%	7.80%
Dec-08	5.92%	6.52%	8.11%	6.85%
Jan-09	6.01%	6.39%	7.90%	6.77%
Feb-09	6.11%	6.30%	7.74%	6.72%
Twelve-Month Average	6.20%	6.57%	7.47%	6.75%
Six-Month Average	6.33%	6.81%	8.08%	7.07%
Three-Month Average	6.01%	6.40%	7.92%	6.78%

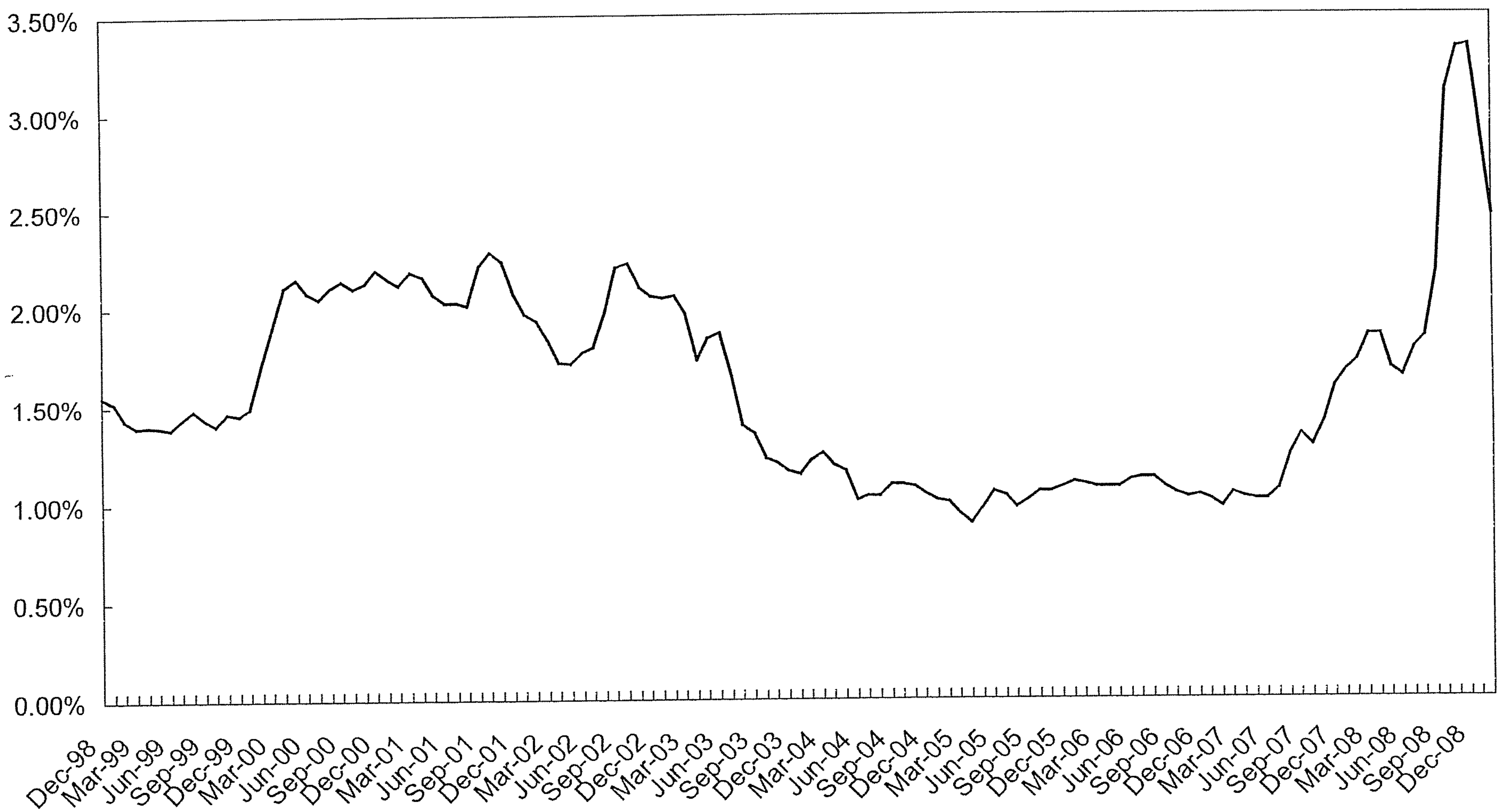
Source: Mergent Bond Record

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



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%	6.07%	6.53%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%	1.08%	1.16%	2.17%

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



A rated Public Utility Bonds over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	Spread	Year	A-rated Public Utility	20-Year Treasuries Yield	Spread	Year	A-rated Public Utility	20-Year Treasuries Yield	Spread
Dec-98	6.91%	5.36%	1.55%								
Jan-99	6.97%	5.45%	1.52%	Jan-03	7.07%	5.02%	2.05%	Jan-07	5.96%	4.95%	1.01%
Feb-99	7.09%	5.66%	1.43%	Feb-03	6.93%	4.87%	2.06%	Feb-07	5.90%	4.93%	0.97%
Mar-99	7.26%	5.87%	1.39%	Mar-03	6.79%	4.82%	1.97%	Mar-07	5.85%	4.81%	1.04%
Apr-99	7.22%	5.82%	1.40%	Apr-03	6.64%	4.91%	1.73%	Apr-07	5.97%	4.95%	1.02%
May-99	7.47%	6.08%	1.39%	May-03	6.36%	4.52%	1.84%	May-07	5.99%	4.98%	1.01%
Jun-99	7.74%	6.36%	1.38%	Jun-03	6.21%	4.34%	1.87%	Jun-07	6.30%	5.29%	1.01%
Jul-99	7.71%	6.28%	1.43%	Jul-03	6.57%	4.92%	1.65%	Jul-07	6.25%	5.19%	1.06%
Aug-99	7.91%	6.43%	1.48%	Aug-03	6.78%	5.39%	1.39%	Aug-07	6.24%	5.00%	1.24%
Sep-99	7.93%	6.50%	1.43%	Sep-03	6.56%	5.21%	1.35%	Sep-07	6.18%	4.84%	1.34%
Oct-99	8.06%	6.66%	1.40%	Oct-03	6.43%	5.21%	1.22%	Oct-07	6.11%	4.83%	1.28%
Nov-99	7.94%	6.48%	1.46%	Nov-03	6.37%	5.17%	1.20%	Nov-07	5.97%	4.56%	1.41%
Dec-99	8.14%	6.69%	1.45%	Dec-03	6.27%	5.11%	1.16%	Dec-07	6.16%	4.57%	1.59%
Jan-00	8.35%	6.86%	1.49%	Jan-04	6.15%	5.01%	1.14%	Jan-08	6.02%	4.35%	1.67%
Feb-00	8.25%	6.54%	1.71%	Feb-04	6.15%	4.94%	1.21%	Feb-08	6.21%	4.49%	1.72%
Mar-00	8.28%	6.38%	1.90%	Mar-04	5.97%	4.72%	1.25%	Mar-08	6.21%	4.36%	1.85%
Apr-00	8.29%	6.18%	2.11%	Apr-04	6.35%	5.16%	1.19%	Apr-08	6.29%	4.44%	1.85%
May-00	8.70%	6.55%	2.15%	May-04	6.62%	5.46%	1.16%	May-08	6.28%	4.60%	1.68%
Jun-00	8.36%	6.28%	2.08%	Jun-04	6.46%	5.45%	1.01%	Jun-08	6.38%	4.74%	1.64%
Jul-00	8.25%	6.20%	2.05%	Jul-04	6.27%	5.24%	1.03%	Jul-08	6.40%	4.62%	1.78%
Aug-00	8.13%	6.02%	2.11%	Aug-04	6.14%	5.07%	1.07%	Aug-08	6.37%	4.53%	1.84%
Sep-00	8.23%	6.09%	2.14%	Sep-04	5.98%	4.89%	1.09%	Sep-08	6.49%	4.32%	2.17%
Oct-00	8.14%	6.04%	2.10%	Oct-04	5.94%	4.85%	1.09%	Oct-08	7.56%	4.45%	3.11%
Nov-00	8.11%	5.98%	2.13%	Nov-04	5.97%	4.89%	1.08%	Nov-08	7.60%	4.27%	3.33%
Dec-00	7.84%	5.64%	2.20%	Dec-04	5.92%	4.88%	1.04%	Dec-08	6.52%	3.18%	3.34%
Jan-01	7.80%	5.65%	2.15%	Jan-05	5.78%	4.77%	1.01%	Jan-09	6.39%	3.46%	2.93%
Feb-01	7.74%	5.62%	2.12%	Feb-05	5.61%	4.61%	1.00%	Feb-09	6.30%	3.83%	2.47%
Mar-01	7.68%	5.49%	2.19%	Mar-05	5.83%	4.89%	0.94%				
Apr-01	7.94%	5.78%	2.16%	Apr-05	5.64%	4.75%	0.89%				
May-01	7.99%	5.92%	2.07%	May-05	5.53%	4.56%	0.97%	Average:			
Jun-01	7.85%	5.82%	2.03%	Jun-05	5.40%	4.35%	1.05%	12-months			2.33%
Jul-01	7.78%	5.75%	2.03%	Jul-05	5.51%	4.48%	1.03%	6-months			2.89%
Aug-01	7.59%	5.58%	2.01%	Aug-05	5.50%	4.53%	0.97%	3-months			2.91%
Sep-01	7.75%	5.53%	2.22%	Sep-05	5.52%	4.51%	1.01%				
Oct-01	7.63%	5.34%	2.29%	Oct-05	5.79%	4.74%	1.05%				
Nov-01	7.57%	5.33%	2.24%	Nov-05	5.88%	4.83%	1.05%				
Dec-01	7.83%	5.76%	2.07%	Dec-05	5.80%	4.73%	1.07%				
Jan-02	7.66%	5.69%	1.97%	Jan-06	5.75%	4.65%	1.10%				
Feb-02	7.54%	5.61%	1.93%	Feb-06	5.82%	4.73%	1.09%				
Mar-02	7.76%	5.93%	1.83%	Mar-06	5.98%	4.91%	1.07%				
Apr-02	7.57%	5.85%	1.72%	Apr-06	6.29%	5.22%	1.07%				
May-02	7.52%	5.81%	1.71%	May-06	6.42%	5.35%	1.07%				
Jun-02	7.42%	5.65%	1.77%	Jun-06	6.40%	5.29%	1.11%				
Jul-02	7.31%	5.51%	1.80%	Jul-06	6.37%	5.25%	1.12%				
Aug-02	7.17%	5.19%	1.98%	Aug-06	6.20%	5.08%	1.12%				
Sep-02	7.08%	4.87%	2.21%	Sep-06	6.00%	4.93%	1.07%				
Oct-02	7.23%	5.00%	2.23%	Oct-06	5.98%	4.94%	1.04%				
Nov-02	7.14%	5.04%	2.10%	Nov-06	5.80%	4.78%	1.02%				
Dec-02	7.07%	5.01%	2.06%	Dec-06	5.81%	4.78%	1.03%				

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2007

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005	4.91%	16.79%	5.87%	3.02%
2006	15.80%	20.95%	3.24%	3.94%
2007	5.49%	19.39%	2.60%	5.20%
Geometric Mean	10.04%	8.92%	5.81%	5.45%
Arithmetic Mean	11.95%	11.24%	6.13%	5.72%
Standard Deviation	20.02%	22.43%	8.52%	7.84%
Median	13.38%	12.05%	4.11%	4.55%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2007, 1952-2007, 1974-2007, and 1979-2007

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2007					
S&P Public Utility Index	8.92%	12.05%		11.24%	
Public Utility Bonds	5.45%	4.55%		5.72%	
Risk Differential	3.47%	7.50%	5.49%	5.52%	5.51%
1952-2007					
S&P Public Utility Index	11.14%	14.00%		12.65%	
Public Utility Bonds	6.15%	5.07%		6.45%	
Risk Differential	4.99%	8.93%	6.96%	6.20%	6.58%
1974-2007					
S&P Public Utility Index	12.98%	15.94%		14.90%	
Public Utility Bonds	8.45%	8.39%		8.79%	
Risk Differential	4.53%	7.55%	6.04%	6.11%	6.08%
1979-2007					
S&P Public Utility Index	13.62%	16.79%		15.41%	
Public Utility Bonds	8.83%	8.65%		9.15%	
Risk Differential	4.79%	8.14%	6.47%	6.26%	6.37%

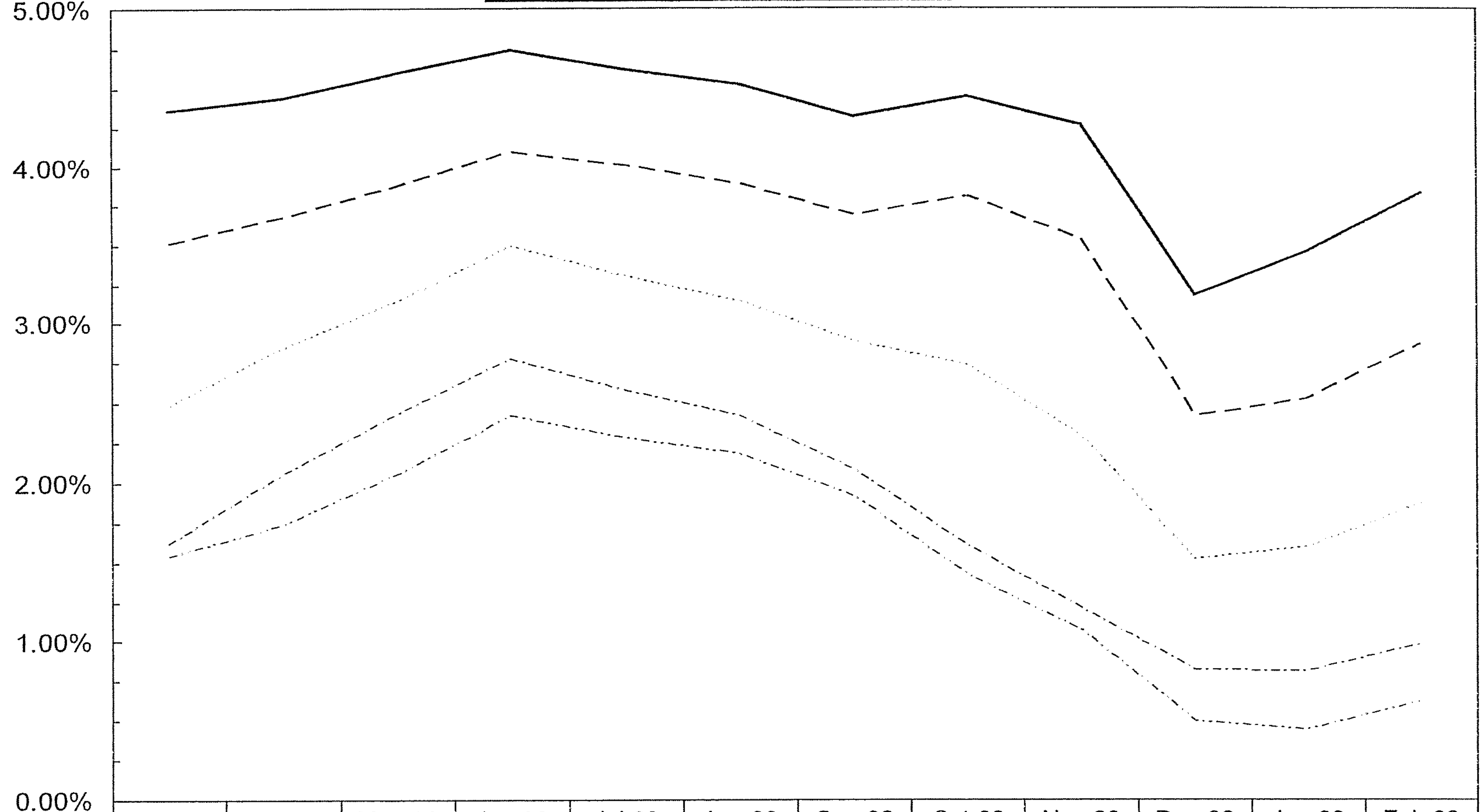
Value Line Betas

Gas Group

AGL Resources, Inc.	0.75
Atmos Energy Corp.	0.65
New Jersey Resources Corp.	0.70
Northwest Natural Gas	0.60
Piedmont Natural Gas Co.	0.70
South Jersey Industries, Inc.	0.75
WGL Holdings, Inc.	0.75
Average	0.70

Source of Information:
Value Line Investment Survey
December 12, 2008

Yields on Treasury Notes & Bonds



	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
1-Year	1.54%	1.74%	2.05%	2.42%	2.28%	2.18%	1.91%	1.42%	1.07%	0.49%	0.44%	0.62%
2-Year	1.62%	2.05%	2.43%	2.77%	2.57%	2.42%	2.08%	1.61%	1.21%	0.82%	0.81%	0.98%
5-Year	2.48%	2.84%	3.14%	3.49%	3.30%	3.14%	2.88%	2.73%	2.29%	1.52%	1.60%	1.87%
10-Year	3.51%	3.68%	3.88%	4.10%	4.01%	3.89%	3.69%	3.81%	3.53%	2.42%	2.52%	2.87%
20-Year	4.36%	4.44%	4.60%	4.74%	4.62%	4.53%	4.32%	4.45%	4.27%	3.18%	3.46%	3.83%

Yields for Treasury Constant Maturities
Yearly for 2003-2007
and the Twelve Months Ended February 2009

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2003	1.24%	1.65%	2.10%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.04%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.64%
2006	4.93%	4.82%	4.77%	4.75%	4.76%	4.79%	4.99%
2007	4.52%	4.36%	4.34%	4.43%	4.50%	4.63%	4.91%
Five-Year Average	3.24%	3.41%	3.58%	3.93%	4.16%	4.40%	4.91%
2008	1.82%	2.00%	2.24%	2.80%	3.17%	3.67%	4.36%
Months							
Mar-08	1.54%	1.62%	1.80%	2.48%	2.93%	3.51%	4.36%
Apr-08	1.74%	2.05%	2.23%	2.84%	3.19%	3.68%	4.44%
May-08	2.05%	2.43%	2.69%	3.14%	3.45%	3.88%	4.60%
Jun-08	2.42%	2.77%	3.08%	3.49%	3.73%	4.10%	4.74%
Jul-08	2.28%	2.57%	2.87%	3.30%	3.60%	4.01%	4.62%
Aug-08	2.18%	2.42%	2.70%	3.14%	3.46%	3.89%	4.53%
Sep-08	1.91%	2.08%	2.32%	2.88%	3.25%	3.69%	4.32%
Oct-08	1.42%	1.61%	1.86%	2.73%	3.19%	3.81%	4.45%
Nov-08	1.07%	1.21%	1.51%	2.29%	2.82%	3.53%	4.27%
Dec-08	0.49%	0.82%	1.07%	1.52%	1.89%	2.42%	3.18%
Jan-09	0.44%	0.81%	1.13%	1.60%	1.98%	2.52%	3.46%
Feb-09	0.62%	0.98%	1.37%	1.87%	2.30%	2.87%	3.83%
Twelve-Month Average	1.51%	1.78%	2.05%	2.61%	2.98%	3.49%	4.23%
Six-Month Average	0.99%	1.25%	1.54%	2.15%	2.57%	3.14%	3.92%
Three-Month Average	0.52%	0.87%	1.19%	1.66%	2.06%	2.60%	3.49%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated February 1, 2009

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	30-Year Treasury Bond
2009	First	0.5%	0.8%	1.5%	2.4%	3.0%
2009	Second	0.6%	0.9%	1.6%	2.5%	3.1%
2009	Third	0.7%	1.0%	1.8%	2.6%	3.2%
2009	Fourth	0.9%	1.2%	2.0%	2.8%	3.4%
2010	First	1.2%	1.5%	2.3%	3.1%	3.7%
2010	Second	1.5%	1.8%	2.6%	3.3%	3.9%

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

THE VALUE LINE Investment Survey®

Part 1
Summary & Index

September 12, 2008

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

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

15.6

26 Weeks Ago	Market Low 10-9-02	Market High 7-13-07
15.5	14.1	19.7

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

2.2%

26 Weeks Ago	Market Low 10-9-02	Market High 7-13-07
2.1%	2.4%	1.6%

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

75%

26 Weeks Ago	Market Low 10-9-02	Market High 7-13-07
75%	115%	35%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

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

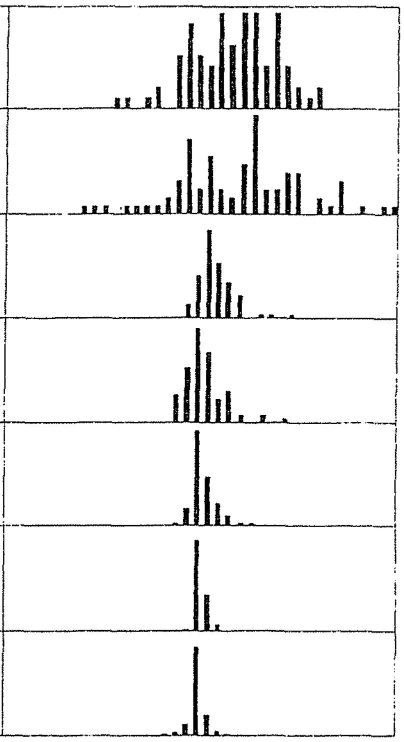
*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXIV, No. 3.
Published weekly by VALUE LINE PUBLISHING, INC. 220 East 42nd Street, New York, N.Y. 10017-5891

Table 2-1
Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2007

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.3%	20.0%	
Small Company Stocks	12.5	17.1	32.6	*
Long-Term Corporate Bonds	5.9	6.2	8.4	
Long-Term Government	5.5	5.8	9.2	
Intermediare-Term Government	5.3	5.5	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.2	



*The 1933 Small Company Stocks Total Return was 142.9 percent

Table 9-1
Building Blocks for Expected Return Construction

	Value (in percent)
Yields (Riskless Rates)[1]	
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	4.9
Intermediate-Term (5-year) U.S. Treasury Coupon Note Yield	4.6
Short-Term (30-day) U.S. Treasury Bill Yield	4.8
Fixed Income Risk Premia[2]	
Expected default premium: *long-term corporate bond total returns minus long-term government bond total returns*	0.2
Expected long-term horizon premium: *long-term government bond income returns minus U.S. Treasury bill total returns**	1.6
Expected intermediate-term horizon premium: *intermediate-term government bond income returns minus U.S. Treasury bill total returns**	1.1
Equity Risk Premia[3]	
Long-horizon expected equity risk premium: *large company stock total returns minus long-term government bond income returns*	7.1
Intermediate-horizon expected equity risk premium: *large company stock total returns minus intermediate-term government bond income returns*	7.6
Short-horizon expected equity risk premium: *large company stock total returns minus U.S. Treasury bill total returns**	8.6
Small Stock Premium: *small company stock total return minus large company stock total return*	5.0

1 As of December 31, 2006. Maturities are approximate.

2 Expected risk premia for fixed income are based on the differences of historical arithmetic mean returns from 1970–2006

3 Expected risk premia for equities are based on the differences of historical arithmetic mean returns from 1926–2006

*For U.S. Treasury bills, the income return and total return are the same

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1 & 2; Financial Strength of B+, B++ & A;
Price Stability of 95 to 100; Betas of .80 to .90; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Allstate Corp.	INSPRPTY	3	1	A	95	0.90	3
BOK Financial	BANKMID	4	2	B++	95	0.85	3
Campbell Soup	FOODPROC	3	2	B++	100	0.85	3
Chubb Corp.	INSPRPTY	3	1	A	95	0.90	3
Cincinnati Financial	INSPRPTY	4	2	B++	100	0.85	3
Commerce Bancshs.	BANKMID	3	1	A	100	0.90	3
ConAgra Foods	FOODPROC	3	2	B++	95	0.80	3
Markel Corp.	INSPRPTY	4	1	A	95	0.80	3
Mercury General	INSPRPTY	3	2	B++	95	0.85	3
Pitney Bowes	OFFICE	3	2	B++	100	0.85	3
Transatlantic Hldgs.	REINSUR	3	2	B++	95	0.80	3
U.S. Bancorp	BANKMID	4	2	B++	95	0.90	3
Average		3	2	B++	97	0.85	3
Gas Group	Average	3	2	B++	100	0.70	3

Source of Information: Value Line Investment Survey for Windows, October 2008

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2003-2007 and
Projected 3-5 Year Returns

Company	2003	2004	2005	2006	2007	Average	Projected 2011-13
Allstate Corp.	12.9%	14.2%	8.7%	22.9%	21.2%	16.0%	13.5%
BOK Financial	12.9%	12.8%	13.1%	12.4%	11.6%	12.6%	12.0%
Campbell Soup	161.8%	74.7%	55.7%	38.5%	59.5%	78.0%	25.5%
Chubb Corp.	8.8%	13.8%	12.7%	17.1%	17.8%	14.0%	11.0%
Cincinnati Financial	6.2%	8.4%	9.2%	7.3%	10.3%	8.3%	8.0%
Commerce Bancshs.	14.2%	15.4%	16.7%	15.2%	13.5%	15.0%	11.5%
ConAgra Foods	18.2%	16.4%	14.5%	12.8%	14.9%	15.4%	15.5%
Markel Corp.	6.1%	9.8%	7.8%	15.2%	13.8%	10.5%	7.5%
Mercury General	14.1%	18.4%	15.1%	11.8%	12.0%	14.3%	14.0%
Pitney Bowes	52.3%	46.0%	48.1%	86.8%	93.5%	65.3%	91.5%
Transatlantic Hldgs.	10.1%	9.3%	0.5%	14.2%	14.4%	9.7%	9.5%
U.S. Bancorp	19.3%	21.3%	22.3%	22.4%	20.5%	21.2%	19.5%
Average						23.4%	19.9%
Median						14.6%	12.8%

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

**PREPARED DIRECT TESTIMONY OF
MARK P. BALMERT
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.**

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF MARK P. BALMERT

Q: Please state your name and business address.

A: Mark P. Balmert, 200 Civic Center Drive, Columbus, Ohio 43215.

Q: By whom are you employed?

A: I am employed by NiSource Corporate Services ("Corporate Services"). The Corporate Services function of NiSource provides, among other services, accounting and regulatory-related services for the NiSource subsidiaries. I am testifying on behalf of Columbia Gas of Kentucky, Inc. ("Columbia," or the "Company"), which is one of the NiSource energy distribution companies.

Q: What is your current position with Corporate Services?

A: I am the Manager of Regulatory Accounting for Corporate Services.

Q: What is your educational background?

A: I graduated from The Ohio State University in June of 1979, earning a Bachelor of Science Degree in Business Administration with a major in accounting.

Q: Please describe your employment history.

A: I was employed by the Columbia Gas distribution companies in October, 1979, as a Rate Analyst in the Rate Department. I was promoted to the position of Senior Rate Analyst in September of 1981. In November, 1984, I was promoted to Rate Engineer, and in July 1986, I was promoted to Senior Rate Engineer. I was promoted to Manager of Regulatory

Support in March, 1991, became Lead IT analyst in November of 1996, and reassigned as Manager of Regulatory Support in May, 1998. In November, 2000, I was named Manager of Regulatory Accounting for Corporate Services, which is the position I currently hold.

Q. What are your responsibilities as Manager of Regulatory Accounting?

A. I supervise and organize the preparation of regulatory compliance filings as requested by the NiSource energy distribution companies. This responsibility includes the preparation of general rate case, informational and gas cost adjustment filings, as well as various special studies. I am also responsible for revenue calculations and related projections for all of the NiSource energy distribution companies excluding Northern Indiana Fuel and Light Company and Kokomo Gas and Fuel Company, as well as pricing for certain functions related to financial planning and internal reporting. I specifically either provide directly or oversee development of support and revenue information for all rate filings and other external filing requirements, as well as for internal information requests related to budgeting and financial planning.

Q. Have you previously testified before this or any other regulatory commissions?

A: Yes, I have testified before this Commission as well as the Public Utilities Commission of Ohio, the Pennsylvania Public Utility Commission, the State Corporation Commission of Virginia, and the Public Utilities Commission of New Hampshire.

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

A: I will describe how billing determinants were derived for the test year from Columbia's billing system, and how the billing determinants were normalized for weather. This information is contained in the work-papers filed with the Application, identified as WPM-B, WPM-C, WPM-D, and WPM-E, which I am sponsoring.

I will also explain the calculations made to determine base period revenues at average rates (Schedule M-2.1 of the Application), annualized test year revenues at most current rates (Schedule M-2.2 of the Application), annualized test year revenues at proposed rates (Schedule M-2.3 of the Application), and the summarized comparison of revenues at current and proposed rates (Schedule M of the Application).

I will explain the calculations made to arrive at base period average rates (WPM-A of the filed work-papers).

I will sponsor the typical bill comparison at current and proposed rates (Schedule N of the Application).

I will also explain Columbia's proposed rider for uncollectible expenses associated with the commodity cost of gas.

I will present and support Columbia's rate design and class cost of service study as required by 807 KAR 5:001 Section 10(6)(u). I have prepared two cost studies, which are included under Tab 39 of the Application, utilizing two different allocation methodologies for the historic test period -- i.e., the twelve months ended December 31, 2008. The only difference between the two methodologies is that one classifies and allocates mains based upon 50 percent demand (design day volumes) and 50 percent commodity (total throughput volumes) while the other classifies and allocates mains based in part upon demand and in part upon the number of customers. The former is commonly referred to as a demand-commodity study and designated as "D/C Study." The latter is commonly referred to as a customer-demand study and is designated as the "C/D Study.

BILLING DETERMINANTS / REVENUE SCHEDULES

Q: Please explain the process that is undertaken to produce the number of bills used to price revenue in this case.

A: Calculations made to determine the number of bills are found in work-paper WPM-B. The number of bills is accumulated by rate code on a customer-by-customer, and month-by-month basis. There are two criteria that the number of bills are based upon: (1) the customer is active in the month; and, (2) the month is within the test year (the twelve months ending December 31, 2008). The bills are accumulated based on which rate schedule the customer is on at the end of the test year. The resulting number of bills by Rate Schedule is recorded in column 1. Adjustments resulting from industrial customers either discontinuing or adding service during the test year are shown in column 3. Incremental residential and commercial customers added during the test year due to new construction or conversion to gas from some other fuel are shown in columns 4 and 5, and backup calculations are shown on work-paper WPM-E. Residential and commercial customers that have discontinued service as of the end of the test year are shown in column 6 and backup calculations are shown on work-paper WPM-E as well. Column 7 shows the number of final bills by rate schedule invoiced to customers that choose to discontinue service. In months that a final bill is issued, the customers are coded inactive and therefore are not counted in the normal customer count for the month even though they are billed a customer charge for their final month of service. Therefore final bills are added to reflect a normal bill count in determining customer charge revenue. Test year adjusted number of bills in column 8 is the sum of columns 1 through 7. Bills in column 1 are shown in Schedule M-2.1 while bills in column 8 are used for pricing in Schedules M-2.2 and M-2.3.

Q: Please explain test year adjusted volumes by Rate Code shown on work-paper WPM-C.

A: Per books adjusted volumes shown in column 8 are the sum of physical flow volumes in column 1, weather normalized volumes in column 2 (see WPM-D), industrial adjustments in column 3 (see WPM-E), new construction in column 4 (see WPM-E), conversions in column 5 (see WPM-E), attrition in column 6 (see WPM-E) and rate schedule transfers in column 7. Volumes in column 8 are used for pricing in Schedules M-2.2 and M-2.3 (revenue at current and proposed rates).

Q: Please explain what Physical Flow volumes in Column 1 of Work-paper WPM-C are, and how they relate to "Actual Invoice Volumes" for the base period shown on Schedule M-2.1.

A: Billed volumes shown on Schedule M-2.1 represent the volumes billed on the customer's monthly invoice including prior month adjustments. These "Actual Invoice Volumes" are also recorded on journal vouchers for Columbia's financial statements. Physical flow volumes are recorded in the billing cycle month in which the gas flows. In months where no billing adjustments occur, a customer's physical flow and actual billed invoice volumes would be the same.

Q: Why are physical flow volumes used as a basis for calculating Columbia's revenue requirement and developing rate design instead of actual billed invoice volumes?

A: Volumes shown on the customer invoices and recorded on Columbia's books may include adjustments made for prior period billings. Some of these adjustments were made to correct billings originally made during a month that is not included within the test year. Adjustments relating to periods that are outside of the test year must be eliminated to reflect representative volumes for determining Columbia's revenue requirement and rate design. Physical flow volumes are used instead of invoice volumes because they represent only volumes flowed during the test year. Columbia captured the monthly volumes by customer that actually were used or flowed by moving all adjusted volumes from the invoice month billing cycle to the month billing cycle for which the adjustment is made. This ensures no out-of-period adjustments are reflected in the test year data, as well as ensuring the proper monthly blocking of rates during the test year.

Q: Please provide an example of invoice volumes versus physical flow volumes.

A: The following is an example of how invoice volumes and physical flow volumes can be different.

December 2007

Customer is billed 1,300 Mcf.

January 2008

Customer is billed 1,000 Mcf, the customer's original December 2007 invoice is adjusted for -300 Mcf.

The accounting books would show 1,300 Mcf for December 2007 and 700 Mcf (1,000 Mcf for January 2008 and –300 Mcf for December 2007 booked in January 2008) for January 2008. The accounting books must show the volumes as they are recorded on the customer's invoice to be consistent with generally accepted accounting principles. However, for rate making purposes, volumes must be recorded in the billing cycle month in which they actually flowed. In this example, Columbia flowed a consistent 1,000 Mcf per month. However, due to a hypothetical error (meter reading, estimating factors, etc.), the customer was over-billed in December 2007 by 300 Mcf and the bill was corrected in January 2008. So on a physical flow basis, both December 2007 and January 2008 are restated to 1,000 Mcf each month. If Columbia does not restate the volumes to a physical flow basis in this example, the test year would be understated by 300 Mcf. This is true because January 2008 is in the test year and December 2007 is not. The 300 Mcf adjustment made in January 2008 for the month of December 2007 is an "out of period adjustment."

Q: Why restate volumes in months that include adjustments that are not "out of period"?

A: Assume in the example that both months were within the test year and the customer was billed on the General Service – Other (GSO) rate schedule. The GSO rate schedule has the following rate blocks:

First 50 Mcf $1.8715/Mcf

Next 350 Mcf $1.8153/Mcf

Next 600 Mcf $1.7296/Mcf

Over 1,000 Mcf $1.5802/Mcf

Using accounting volumes the pricing would be as follows:

<u>December 2007</u>

50 Mcf x $1.8715/Mcf = $93.58

350 Mcf x $1.8153/Mcf = $635.36

600 Mcf x $1.7296/Mcf = $1,037.76

300 Mcf x $1.5802/Mcf = $474.06

1,300 Mcf total = $2,240.76

<u>January 2008</u>

50 Mcf x $1.8715/Mcf = $93.58

350 Mcf x $1.8153/Mcf = $635.36

300 Mcf x $1.7296/Mcf = $518.88

700 Mcf total = $1,247.82

Total December and January = $3,488.58

Using Physical Flow volumes the pricing would be as follows:

<u>December 2007</u>

50 Mcf x $1.8715/Mcf = $93.58

350 Mcf x $1.8153/Mcf = $635.36

600 Mcf x $1.7296/Mcf = $1,037.76

1,000 Mcf total = $1,766.70

January 2008

50 Mcf x $1.8715/Mcf = $93.58

350 Mcf x $1.8153/Mcf = $635.36

600 Mcf x $1.7296/Mcf = $1,037.76

1,000 Mcf total = $1,766.70

Total December and January = $3,533.40

In this example, volumes would be under priced by $44.82 compared to the net amount actually billed to the customer if accounting "per books" volumes were picked up in the month they were recorded and then priced for rate making purposes. Because Columbia utilizes block rates in most of its rate schedules, it is imperative that volume adjustments are first moved to the physical flow month before pricing. Failure to do so would result in misrepresenting the revenue generated from those volumes delivered, and therefore, also the revenue requirement required to earn allowed returns in this case.

Q: How were the physical flow volumes in Column 1, work-paper WPM-C split by rate block?

A: A bill frequency was created for each rate schedule for each month of the test year at 45 usage levels including those levels that coincide with the rate blocks of the pertinent rate schedule. For residential and small commercial rate schedules, the Ogive method was used to create the bill frequencies. Ogive is a statistical term for a distribution curve in which the frequencies are cumulative. This method has been used by Columbia since the 1950s and still proves to be highly accurate to within a minimum of 0.5% of actual billings. For rate schedules that do not have a predictable distribution curve, Bill Frequencies were created by accumulating volumes on a customer-by-customer, month-by-month basis. These rate schedules include large volume General Service sales, Intrastate Utility service, and all Delivery Service.

Q: Are there any differences in the methods used to create bill frequencies in this filing and that presented in Columbia's last general rate case?

A. No.

Q: Are there any differences in the weather adjustment included in this filing and that presented in Columbia's last general rate case?

A: Yes. Columbia witness Efland will address proposed changes in her prepared direct testimony.

Q. How were Ms. Efland's total company normalized volumes used in determining normalized revenue?

A. Once total normalized volumes by month, and by class were determined, these totals were spread back on a customer-by-customer, month-by-month basis, based on the customer's actual physical flow volumes and customer class. Normalized volumes by customer were then accumulated by rate schedule, by rate block, on a month-to-month basis in a manner identical to how work-paper WPM-C Column 1 is described above. The physical flow volumes by rate schedule by rate block from work-paper WPM-C Column 1 are shown in Column 1 of work-paper WPM-D. Column 2 of work-paper WPM-D is where the accumulated normalized volumes by rate schedule by rate block are recorded. The Weather

Normalized Adjustment in Column 3 of work-paper WPM-D is calculated by subtracting physical flow volumes in Column 1 from the normalized volumes in Column 2. The Weather Normalization Adjustment is then recorded in Column 2 of work-paper WPM-C. Current base rates are shown in Column 4 of work-paper WPM-D, and Column 5 shows the revenue impact of the Weather Normalization Adjustment.

Q: Please explain the adjustments made for industrial customers in WPM-C column 3.

A: Column 3 shows the elimination of test year volumes of industrial and large commercial customers who became inactive during the test year and remained inactive as of the end of the test year. In addition, column 3 shows the inclusion of volumes from the beginning of the test year through the customer's start of service month for industrial and large commercial customer that became active during the test year. These adjustments can be found in work-paper WPM-E, page 7 and summarized on pages 1 and 2.

Q: Please discuss adjustments made for New Customers (column 4), Conversion customers (column 5), and Attrition (column 6) of work-paper WPM-C.

A: For space heating customers, actual monthly customer additions in the test year were divided into two categories: new construction and conversions from other fuels. The monthly volume per customer for these categories was determined from Columbia's residential and commercial databases. Total annual customer additions were then applied to normalized volumes per customer to calculate annualized volume for total customer additions (i.e. the amount of gas that would have been consumed by the added customers if they had all consumed gas for the entire test year). Calculations are shown on work-paper WPM-E sheets 3 through 6 and summarized on sheets 1 and 2. The number of other heating customers (not new construction or conversion gains during the test year) either fell or rose depending on the net effect of attrition (customer loss) and non-heat customers adding heating equipment (customer gains). In either case, this change in the number of customers was evaluated at half the annual volume per customer of this group. That is, it was assumed that the customer loss (gain) occurred evenly throughout the year, therefore, half the volume was subtracted (added) for the loss (gain) in customers. A summary of attrition is shown in work-paper WPM-E sheets 1 and 2.

The loss (gain) in non-heat customers was also evaluated at half the volume per customer of that group, where half the volume was subtracted (added) for the loss (gain) in customers.

Q: Please explain how Schedule M-2.1 (Base Period Revenue at Average Rates) was developed.

A: Actual test year customer bills in column C are recorded from work-paper WPM-B column 1. Column D shows actual billed volumes as they are recorded on the customer's monthly invoice (not physical flow). Column I shows the calculated gas cost during the test year based on a weighted average cost of gas calculated in work-paper WPM-A. Column J shows the total actual billed revenue during the test year. Column E is the difference between column J and column I. Other Gas Department Revenue is recorded directly from Columbia's financial statement. Each class of revenue was reconciled back to Columbia's Financial Statements. There were four main categories of reconciliation: (1) Supplier Refunds are recorded on Columbia's books on a normalized basis; (2) Unbilled Revenue is recorded on Columbia's books to reflect calendar based revenue; (3) Transportation Service and Large Sales Service revenues are booked as estimates for current month and trued-up in the following month; and, (4) Contributions in aid of construction being collected from one customer is not recorded as revenue on the Company's books.

Q: How was the weighted average cost of gas used in Schedule M-2.1 calculated for the test year?

A: Gas cost rates were applied to volumes (Mcf) for each month of the test year based on rate class. Calculations are shown on work-paper WPM-A.

Q. Please explain how Schedule M-2.2 (Annualized Test Year Revenues at Most Current Rates) was developed.

A: Pro forma customer bills in column C are recorded from work-paper WPM-B column 8. Annualized volumes in column D are from work-paper WPM-C, column 10. Column J shows base delivery charge rates currently in effect. Column K (Current Revenue Less Gas Cost revenue) is equal to column D (Annualized Volumes) * column J (Current Rates). Column M (Revenue Incr. In Rev Less Gas Cost Rev) is equal to column F on Schedule M-2.3 less column K on Schedule M-2.2. Column H (Gas Cost Revenue) is calculated by applying the latest Commission-approved Expected Gas Cost Rate of $10.1224/Mcf effective March 2, 2009 to annualized volumes. Column K1 (Current Total Revenue) is equal to column J (Current Revenue Less Gas Cost) plus column H (Gas Cost Revenue).

Q: Please explain how Schedule M-2.3 (Annualized Test Year Revenues at Proposed Rates) was developed.

A: Pro forma customer bills in column C and annualized volumes in column D are identical to Schedule M-2.2 Column E shows proposed base delivery charge rates. Column F (Proposed Revenue Less Gas Cost revenue) is equal to column D (annualized Volumes) * column E (Proposed Rates). Column H (Gas Cost Revenue) is calculated by applying the latest Commission-approved Expected Gas Cost Rate of $10.1224/Mcf effective March 2, 2009 to annualized volumes. Column I (Proposed Total Revenue) is equal to column F (Proposed Revenue Less Gas Cost) plus column H (Gas Cost Revenue).

Q: Please explain how Schedule M was developed.

A: Column B (Revenue at Present Rates) is recorded from Schedule M-2.2, column K1. Column C (Revenue at Proposed Rates) is recorded from Schedule M-2.3, column I. Column D (Revenue Change) is equal to column C – column B.

Q: Please explain how Schedule N (Typical Bill Comparison) was developed.

A: Monthly usage levels were selected in order to give a representative effect of the change in a typical monthly bill based on proposed rates as compared to current rates. Tariff sales rate schedules were compared with and without gas cost. Customer and commodity charges were compared for transportation rate schedules.

CLASS COST OF SERVICE

Q: Why did you conduct two cost of service studies?

A: Columbia believes that both methodologies are relevant. They provide the outside limits of the possible allocations of mains to the various classes of service – i.e., the demand-commodity study produces results that are generally more favorable to the residential class while the customer-demand study produces results that are generally more favorable to the industrial class. Columbia recognizes that no one cost of service study is the "right" study, and the results of two such studies are useful in providing a reasonable range of returns for use as a guide in establishing appropriate rates.

Q: Has the Commission accepted Columbia's two-study approach in previous proceedings?

A: Yes, Columbia has filed two studies using the two methods discussed above in previous rate cases in Kentucky, such as Case No. 2007-00008, 2002-00145 and 94-179. Columbia has also supported this approach in rate case filings in other jurisdictions where Columbia operates. The Commission has accepted Columbia's use of multiple cost-of-service studies in previous proceedings and has encouraged Columbia to continue using multiple studies.

Q: How were the rate schedules grouped in allocating the cost of service?

A: Generally speaking, the rate schedules were grouped on a throughput or complimentary rate schedule basis. Sales and transportation rate schedules having similar service characteristics and requirements were combined under the same rate schedule category. For example, residential sales service and residential transportation service were combined under GS-Res. This combination is appropriate since the customer pays virtually the same utility costs for either service.

Q: Please explain how the demand component of mains was allocated in each study.

A: In the Demand-Commodity study, each component is considered to have equal weight regarding mains; therefore, the demand component was used to allocate 50% of the cost of mains. In the Customer-Demand study, the demand component is the portion remaining after the customer component is determined using the "minimum system" methodology. In this case, the demand component is 38.682%. I then allocated the demand component of mains to the various classes based on design-day throughput (gas sales and transportation) in each study.

Q: Describe the methodology used in determining the customer component of mains in your customer-demand study.

A: As mentioned above, mains were allocated utilizing the minimum system concept, which is described in detail in Attachment MPB-2. As shown in the attachment, the minimum system concept identified a significant portion (approximately 61 percent) of mains costs as being customer related.

Q: Were any customers or customer groups excluded from the allocation of mains?

A: Customers served under rate schedule Delivery Service – Main Line Service/ Special Contract (DS-ML/SP) were excluded from the allocation of mains. These customers are served directly from a Columbia Gas Transmission, LLC interstate pipeline. Columbia has no main investment associated with providing service to these customers. Therefore, it is appropriate to exclude them from the allocation of mains and mains related cost.

Q: Is Columbia's investment and expense related to mains and services and the allocation of those items significant in the outcome of the studies?

A: Yes, it is. Mains and services account for 80% of plant investment and approximately 13% of Operating and Maintenance expenses excluding gas costs. The allocation of these items significantly influences the outcome of the studies. In addition, many other elements of operation and maintenance expenses are allocated on plant-related factors.

Q: Please describe how you allocated plant Account 380 - Services and the related O&M accounts.

A: I have allocated Account 380 - Services and the related O&M accounts based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size and kind from Columbia's Distributive Information System ("DIS") and accumulated by customer class and rate schedule. The services were valued for each rate schedule using the average unit cost based on detailed capitalized property records. This method is preferred since it utilizes an actual assignment of services by rate schedule and customer.

Q: Please explain the method of allocating Accounts 381 - Meters and 382 - Meter Installations.

A: I have assigned meters to the various classes of customers based on an actual inventory of meters installed on customers' premises. Individual customer meters were identified by size and kind from Columbia's DIS and accumulated by customer class and rate schedule. The meters were then valued by size using unit costs based on detailed capitalized property records. This method is preferred because it utilizes an actual inventory of company records by class to develop the allocation factors.

The allocations calculated for Account 381 - Meters were used to allocate costs in Account 382 - Meter Installations, Account 383 - House Regulators and Account 384 - House Regulator Installations in all of the current studies since these costs are incurred in direct association with meters.

Q: Do you provide a more complete description of how these factors were developed and the related calculations?

A: Yes. In Attachments MPB-1 and 2 of this testimony, entitled Development of Allocation Factors, I have provided a description and, where needed, a calculation for these and all other factors used in both studies. In addition, in Attachments MPB-3 and 4, I have provided the rationale for factor selection, by account, as it pertains to the various categories of rate base and expense.

Q: Please proceed with your description of the two studies you are supporting.

A: Both Cost Allocation Studies, D/C and C/D, consist of a table of contents plus 28 pages that show the detailed calculations supporting the allocation of income and rate base used to compute the rates of return by rate schedule.

The rates of return that are shown on page 1 of the studies are based on income generated using proposed rates. The proforma adjustments on page 2 are added to the income statement on page 3 to produce page 1. Both page 1 and page 3 summarize the same allocated cost of service with the exception of income taxes, commission fees and uncollectibles which vary with the changes in revenue level determined on page 2. Returns at current rates are summarized on page 3. The allocation of gross plant investment is shown on pages 4 through 7, while pages 8 through 11 contain the reserve for depreciation and depreciation expense. Revenue by account and rate schedule is summarized on page 12 and pages 13 through 19 contain the allocation for operation and maintenance expenses. Labor and materials & expense allocations are on page 20. Taxes other than income taxes, state income taxes and the calculation of federal income taxes are on pages 21 and 22-25 respectively. Working capital and rate base are summarized on page 26 while pages 27 and 28 contain the allocation factors used throughout the study.

RATE DESIGN

Q: Is Columbia proposing any changes to its rate design?

A: Yes, Columbia is proposing three changes from the method adopted by the PSC in Columbia's last rate case, Case No. 2007-00008. First, Columbia proposes to remove from base rate recovery the amount of uncollectible accounts Columbia incurs as the commodity cost of gas is billed to customers and Columbia instead proposes to recover this cost through a separate volumetric surcharge rate. Second, Columbia proposes a graduated migration to a straight fixed variable ("SFV") rate design to recover Columbia's cost of service for the General Service – Residential rate class. Third, Columbia proposes to apply a Late Payment Penalty to the Residential customer class. The penalty currently applies only to the Commercial and Industrial customer classes as described in Columbia's tariff (P.S.C. Ky. No. 5 General terms, Conditions, Rules and Regulations, Section 25).

Q: Please explain why Columbia proposes to recover uncollectible accounts expense through a separate surcharge rate instead of traditional recovery through base rates.

A: Historically, uncollectible accounts expense has been recovered through Columbia's base rates. The basis of recovery was set in a base rate case and was based in part on the revenues generated by Columbia's last approved gas cost recovery rates as of the filing date to determine an annualized expense level. The problem with this method of recovery is that it relies on relatively stable gas cost recovery rates to afford Columbia the reasonable opportunity to recover the uncollectible expense assumed for ratemaking purposes. In fact, looking at the last five years of uncollectible expense experience, the price of gas has been volatile, and this has been reflected in Columbia's commodity Expected Gas Costs ("EGC") rates.

To illustrate my point, Attachment MPB-5 page 1 shows a graph that compares Columbia's EGC rates for the last five years to the EGC levels that were the basis of uncollectible account expense recovery through Columbia's base rates. In each instance where the solid line (actual commodity EGC rates that were billed) is higher that the dashed line (the EGC used as a basis of calculating uncollectible account expense recovery in base rates), Columbia under recovered the cost of uncollectible accounts as they were incurred assuming all other factors being equal. In the instance where the solid line is lower that the dashed line as in September 2007 through February 2008 Columbia over recovered the cost of uncollectible accounts as they were incurred assuming all other factors being equal. Attachment MPB-5 page 2 shows the detail rates used in the graph.

Q: Have you attempted to quantify the over and under recoveries of actual uncollectible expense resulting from the billing of the EGC commodity rates over the last 5 years?

A: Yes I have. Columbia has under recovered uncollectible expense as a result of billing the EGC commodity rate by $1,426,488.34 over the last 5 years. To determine this under recovery I first calculated the uncollectible expense Columbia incurred by billing the EGC commodity rate each month for the last 5 years using actual booked Account 904 expense and actual invoiced revenue and volumes. (see Attachment MPB-5 pages 3 and 4). Then I calculated the amount of recovery for the last 5 years by applying the uncollectible percentage established in the applicable base rate filings to the EGC commodity rate used in the filings to determine a rate per Mcf of recovery embedded in the effective base rates. Finally, I applied the rate per Mcf to the EGC billed volumes to determine recovery revenue (see Attachment MPB-5 page 5). A summary comparison shown on Attachment MPB-5 page 6 shows the over/under recovery of uncollectible expense Columbia incurred as a result of billing the EGC commodity rate by year for the last 5 years.

Q: What conclusions do you draw from Attachment MPB-5?

A: Attachment MPB-5 page 6 summarizes that there has been a lack of correlation between cost incurrence and cost recovery as it pertains to the uncollectible accounts expense generated from commodity gas cost recovery revenues in the last 5 years. In fact, Columbia lost in excess of $1.4 million dollars over the last 5 years solely from the existing rate design that freezes the recovery rate of uncollectible expense at the EGC commodity rate in effect at the time base rates were approved. Attachment MPB-5 page 1 illustrates that this is due to the volatile and fluctuating nature of the EGC commodity rates. The EGC commodity rates are market driven and consequently when billed, generate an uncollectible cost over which Columbia has little or no control.

Q: What is Columbia's proposal to address this problem?

A: Columbia proposes to remove only the portion of uncollectible expense that pertains to the calculated commodity cost of gas used in the determination of revenue requirement in this case from the determination of base rates, and to instead recover that same expense through a surcharge calculated using the commodity EGC rate in effect at the time of billing.

Q: How will Columbia remove the portion of uncollectible expense that pertains to the calculated commodity cost of gas used in the determination of revenue requirement from the determination of base rates?

A: Footnote 1 on page 3 of Attachment MPB-6 shows the calculated surcharge rate of \$0.0964/Mcf using the commodity EGC rate in effect as of March 1, 2009, that is applied to gas cost recovery volumes to determine the amounts removed from revenue requirement to determine base rates. As a result, \$657,997 from General Service - Residential base rates, \$403,473 from General Service – Other base rates, and \$1,845 from Intrastate Utility Service are excluded (see Attachment MPB-6 pages 1 through 3).

Q: How will the uncollectible surcharge be calculated?

A: The uncollectible surcharge which Columbia will refer to as the Gas Cost Uncollectible Charge will be calculated quarterly (March, June, September, December) by multiplying the commodity EGC recovery rate in Columbia's quarterly Gas Cost Adjustment ("GCA") filing by the uncollectible percentage of 1.410552% supported by witness Racher on

Schedule D-2.1 Sheet 5, Line 4 in this case. The revised uncollectible surcharge rate will be filed at the same time Columbia files its quarterly adjustments to its GCA rates.

Q: How will the uncollectible surcharge be billed?

A: The surcharge will apply to the same volumes as Columbia's GCA. The surcharge rate will be added to the GCA rate on the customer's invoice before being applied to sales volumes.

Q: Is Columbia proposing a mechanism to determine over/under collections of the proposed Gas Cost Uncollectible Charge?

A: No. There is no proposed reconciliation of costs and revenues. It is simply a mechanism to better align cost recovery with cost incurrence, not a guaranteed dollar for dollar recovery. The current practice of embedding the recovery of uncollectible expense associated with the EGC commodity rate in base rates does not allow for a reasonable opportunity to recover cost due to the volatile and fluctuating nature of the EGC commodity rate. Removing the recovery of uncollectible expense generated from billing the EGC commodity rate from a fixed base rate recovery and allowing recovery to vary with the change in the EGC commodity rate allows for a better alignment of recovery with cost incurrence and thereby limits the possibility of severe over or under recovery.

Columbia will continue to be at risk that the fixed uncollectible percentage determined by Columbia witness Racher in Schedule D-2.1 Sheet 5 may under recover actual uncollectible expense.

Q: In the event the Commission does not approve Columbia's request for the Gas Cost Uncollectible Charge, what do you propose?

A: In the event the PSC does not approve Columbia's request for an Uncollectible Expense Rider I recommend that the Commission permit Columbia to recover uncollectible expense generated by billing the EGC commodity rate through the base rates as has been the practice in Columbia's past rate cases.

Q: Does Columbia's rate design in Attachment MPB-6 include the recovery of uncollectible expense generated by billing the EGC commodity rate in proposed base rates?

A: No. The proposed rate design reflects recovery of uncollectible expense generated by billing the EGC commodity rate through the proposed Gas Cost Uncollectible Charge, not in base rates.

Q: In the event that the Commission does not approve Columbia's request for the Gas Cost Uncollectible Charge, would the proposed base rates in Attachment MPB-6 have to be redesigned to include the recovery of the uncollectible expense?

A: Yes.

Q: How is Columbia proposing to assign the additional revenue required to eliminate its revenue deficiency?

A: Using both the Customer/Demand and Demand/Commodity class cost of service studies as a guide, and the goal of migrating all classes of customers toward earning the proposed return on rate base of 9.00%, Columbia proposes to allocate the $11,565,731 of additional revenue requirement in the following manner: 89.00% to the GSR/GTR class, 10.31% to the GSO/GTO/GDS class, 0.60% to the DS/IS/SAS class and 0.09% to the IUS class. Columbia proposes no increase in rates to the DS3 (DS-ML) class nor does it proposed an increase to customers on contract rates or those flexing for competitive reasons. Columbia will also not apply an increase to its few customers currently being served on the current Louisville Gas and Electric ("LG&E") tariff rates (LG&E's rate schedules G1R and G1C) as approved by the Commission and customers that are billed contractually based rates under certain right of way agreements with those customers. I believe Columbia's assignment of the additional revenue requirement demonstrates a reasonable movement of class rates toward a uniform return on rate base.

Q: What are the rate increases for the various rate classes?

A: The rate increases range from 1.50% for Delivery Service ("DS/IS/SAS)" class to 9.93% for the General Service-Residential class ("GSR/GTR").

Q: Where are the existing and proposed rates by customer class shown?

A: Attached to this testimony as Attachment MPB-6 is a schedule showing the existing and proposed rates by customer class.

Q: Why is the GSR/GTR class receiving the largest percentage increase?

A: The two Class Cost of Service studies show that the GSR/GTR class is being subsidized by the other customer classes. To reduce this subsidy, the largest percentage increase was allocated to the GSR/GTR class. However, in the interest of gradualism, Columbia limited the increase in revenue to the GSR/GTR class to less than 10%.

Q: How does Columbia propose to recover the allocated proposed increase to the GSR/GTR class?

A. For GRS/GTR customers, Columbia proposes to recover its uncollectible expense generated by billing the EGC commodity rate through the proposed Uncollectible Expense Rider of $0.0964/Mcf (See Attachment MPB-6, page 3, footnote 1). Recovery of all other fixed costs for Columbia's delivery system would be phased in over two steps reflecting a shift from volumetric recovery of fixed costs to a single monthly fixed charge. Under Columbia's SFV rate design proposal, the monthly fixed charge for the GSR/GTR rate schedule is proposed to increase from the current charge of $9.30 per month to $17.92 per month during the first year the proposed rates will be in effect. The second year the proposed rates will be in effect the fixed charge will increase to $26.53 per month. Therefore, Columbia's fixed costs of natural gas delivery service will be recovered from these customers through a single, fixed monthly charge called the Customer Delivery Charge.

The volumetric charge is proposed to decrease from the current level of $1.8715 per Mcf to $1.4604 per Mcf during the first year the proposed rates will be effective and the volumetric charge for delivery service will be eliminated beginning with the second year.

Q: How does Columbia propose to recover the allocated proposed increase to the GSO/GTO/GDS class?

A: Columbia has proposed to recover the entire proposed increase through the customer charge by increasing the GSO/GTO/GDS customer charge from the current $23.96 per month to $28.28 per month. Even with the proposed increase, the proposed customer charge is still less than the cost based customer charge of $36.63 calculated in Attachment MPB-7. The customer charge proposed by Columbia is consistent with the desire to design rates based on cost causation. Additionally, this Commission has, in the past, recognized the distinction between fixed customer costs and variable commodity related costs and agreed that rate design should move to more closely reflect this distinction.

Q: How does Columbia propose to recover the allocated proposed increase to the DS/IS/SAS class?

A: As with the GSO/GTO/GDS class, Columbia has proposed to recover the entire proposed increase through the customer charge by increasing the DS/IS customer charge from the current $547.37 per month to $620.18 per month. Even with the proposed increase, the proposed customer charge is still less than the cost based customer charge of $1,083.99 calculated in Attachment MPB-7.

Q: How does Columbia propose to recover the allocated proposed increase to the IUS class?

A: Columbia has proposed to increase the customer charge from $255.00 per month to $331.50 per month. The proposed $331.50 per month customer charge is the amount calculated in the class cost of service study (see Attachment MPB-7) that will match cost recovery with cost causation for the IUS class. The remainder of the increase will be recovered by increasing the current volumetric charge from $0.5905/Mcf to $0.8729/Mcf.

Q: Why has Columbia proposed to subject the Residential customer class to the Late Payment Penalty described in Section 25 of the General Terms, Conditions, Rules and regulations?

A: Columbia believes the 5% penalty currently assessed to the Commercial and Industrial customer classes has served as an incentive for customers to pay their bills by the due date. A similar incentive applicable to residential customers will help reduce the uncollectible expense attributable to the Residential class. In addition, in the interest of matching recovery with cost causation, Columbia believes that the costs that Columbia incurs resulting from a delay in payments past the due date by the Residential class of customers should not be shared by all customers but instead be recovered from the customers who cause the cost.

Q: In your rate design, have you accounted for expected revenues generated by Columbia's proposed assessment of the Late Payment Penalty to the Residential customer class?

A: Yes I have. Attachment MPB-6 Sheet 4 Line 26 shows that the ratio of test year late payment penalty revenue to total revenue billed to the Commercial and Industrial rate schedules that were subject to the late payment penalty was .00264105 to 1. In other words, $264.11 in late payment penalties were assessed during the test year for every $100,000 in revenue that was billed. Applying Columbia's test year experienced ratio to proposed revenue generated by all rate schedules proposed to be subject to the late payment penalty generates proposed forfeited discount revenue of $457,773. Compared to test year revenue of $192,713 I have reflected an expected additional $265,020 of late payment penalty revenue that has been used to reduce the revenue requirement for base rate design (see Attachment MPB-6, Sheet 1, line 23).

Q: **In the event that the Commission does not approve Columbia's request to make the Late Payment Penalty applicable to the Residential customer class, would the proposed base rates in Attachment MPB-6 have to be redesigned to exclude the expected contribution of revenue generated by assessing the penalty to the Residential customer class?**

A: Yes.

Q: Other than the Class Cost of Service studies are there other guidelines or criteria that should be considered in the design of gas utility rates?

A: Yes, in my opinion, there are at least three criteria to consider in the design of rates:

1) Design of gas utility rates should recognize that rates must be just and reasonable and must avoid undue discrimination. Columbia's proposed rate design is working toward eliminating class subsidies.

2) Where rates need to be adjusted to achieve proper cost recovery, customer impact considerations should also be factored into the rate design process. Columbia's proposed rate design limits the increase to any one class to 10%.

3) Rates should provide financial and earnings stability for the Company. In recognition of this goal, it is generally not a sound ratemaking practice to provide for recovery of a substantial portion of fixed costs, such as customer-related costs that bear no relationship to customer gas consumption patterns, in the volumetric rate portion of the rate schedule. Recovery of fixed costs through volumetric rates detracts from earnings stability because the revenues generated from customers' volumetric use of gas can be greatly sensitive to load variation due to customers' conservation efforts or other changing consumption characteristics, and thus, subject to recovery from sales volumes and revenues that fluctuate. Columbia's proposed rate design adds proposed increased revenue to the customer charges for the GSO/GTO/GDS, DS/IS, and IUS rate classes up to the cost based customer charges shown in the Class cost of service study (Attachment MPB-7). Columbia also is proposing a SFV rate design for the Residential class.

Q: Under Columbia's rate design proposal for Rate Schedules GSR/GTR, why is the chosen type of rate structure characterized as "Straight-Fixed Variable?"

A: It is characterized as "Straight-Fixed Variable" because all fixed costs incurred by the utility are recovered from customers through fixed charges, while all variable costs are recovered through variable charges. This pricing concept was first adopted in the gas pipeline industry, and in more recent times, it was adapted for use by gas distribution utilities. One difference in the application of the concept is that for gas pipelines, their fixed costs are recovered through monthly demand charges that are assessed to customers based on their pre-determined contract demand levels, while for gas distribution utilities, the fixed costs are recovered through monthly customer or service charges. A SFV rate structure achieves a fundamental objective of ratemaking – the proper alignment of costs with revenues and rates.

Q. Why is Columbia proposing the above-described rate design changes at this time?

A. Columbia is proposing these rate design changes at this time because they best address the major business challenges faced by Columbia, such as: 1) declining use per customer; 2) volatile wholesale natural gas prices; and, 3) the desire to promote conservation.

These are serious challenges to Columbia's financial integrity and to the ability of its customers to manage their energy needs. In addition, the fixed cost nature of the gas distribution business warrants new approaches to the traditional ratemaking process in order that Columbia be given a reasonable opportunity to recover its fixed costs of providing gas delivery service, and that its customers pay for that service in an appropriate and equitable manner.

Q. How were Columbia's current GSR/GRT base rates developed?

A. While the following explanation is somewhat simplified, essentially the utility's unit rates and charges for gas service were derived by simply dividing the appropriate costs, or portion of the utility's revenue requirement, to be recovered through rates by the weather-normalized gas volumes. These rates and charges should be designed to provide the utility with a reasonable opportunity to recover the significant level of fixed costs (including a return on its investment) it incurs to provide utility service, at the levels determined in the utility's last completed rate case. Fixed costs are costs incurred by a utility that do not vary with the amount of gas delivered to customers. For Columbia, these costs are composed of fixed O&M expenses, administrative and general expenses, depreciation, certain taxes, working capital requirements, and return on investment. These costs do not vary with the associated changes in customers' gas consumption. Therefore, as a result of changes in customers' gas consumption, the margin revenues, and resulting earnings of Columbia can vary significantly from the levels authorized in Columbia's last rate case.

Q. Please explain more specifically what you mean by "margin revenues."

A. Margin revenues relate to Columbia's total cost of service exclusive of purchased gas expenses and any other expenses that simply are treated as "flow-through" items in rates. Columbia's margin revenues are to recover its overall costs of operations, most of it fixed, including a fair and reasonable return on its utility assets as determined by the Commission in Columbia's most recently completed base rate case. While a portion of fixed margin may be recovered through fixed charges such as a monthly customer charge, a portion of fixed margin is also recovered through the volumetric distribution charge.

For Columbia, more than 54% of its delivery charge revenue is currently recovered through the volumetrically-applied delivery charges in its GSR/GTR rate schedules.

Q. Is it important that Columbia realizes the margin that was allowed by the Commission in the utility's most recent rate case?

A. Yes. The utility's financial health directly relies upon its ability to recover the cost of service inherent in the margin approved by the Commission through the margin revenues upon which its base rates were previously established.

Q. Historically, has Columbia experienced a decline in gas use per customer?

A Yes, and the declines in gas use per customer have been substantial. Attachment MPB-8 demonstrates that over the last ten years, the annual average use per customer has declined significantly in Columbia's Residential customer class. Columbia's customers during that period have shown a material reduction in their gas consumption caused primarily by increased efficiency of gas appliances (especially space heaters), reduced appliance saturation in homes with natural gas, and tighter, more energy efficient homes.

Q. Against what reference point should Columbia's decline in use per customer be reviewed?

A. The reference point should be the use per customer levels established in each of Columbia's previous base rate cases. Referring to page 1 of Attachment MPB-8, the annual "baseline" use per customer for the Residential class established in Columbia's last base rate cases to design the Company's base rates were as follows:

From	To	Case	Usage per Customer
1-1-1998	3-1-2003	94-179	98 Mcf
3-1-2003	9-1-2007	2002-00145	84 Mcf
9-1-2007	12-31-2008	2007-00008	69 Mcf

You can readily see that over the succeeding years after a rate case was completed, Columbia never experienced a gas sales level equal to the "baseline" use per customer figure.

Q. What conclusions do you reach from this assessment?

A. The Company's "baseline" use per customer levels established in its previous rate cases were not representative of the actual use per customer it experienced in subsequent years, even though Columbia has had a weather normalization adjustment clause in effect since July 2000. In fact, the data presented in Attachment MPB-8 demonstrates that the "baseline" use per customer level for Columbia's Residential rate class was always high relative to the billed amounts with the exception of 2008. To the extent the "baseline" use per customer level is not representative of Columbia's expected future trends, its base rates will not properly recover the fixed costs incurred to provide its customers with gas delivery service.

Q. Have you examined how the margin revenues collected by Columbia have varied historically?

A. Yes. Attachment MPB-9 presents the margin impact experienced by Columbia in its GSR/GTR rate class due to fluctuations in gas volumes caused by declining use per customer. Over the last 10 years, Columbia incurred margin losses in each of those years with the exception of 2008. The total margin losses (i.e., the loss of margin revenues derived from Columbia's volumetric charges during that period amounted to over $19 million, or approximately $1.9 million per year. As a point of reference, Columbia's total approved margin level (including Customer Charge and Delivery Charge revenue) for the GSR/GTR rate class in its last rate case was approximately $30.6 million.

Q. Is Columbia's experience unusual in the gas distribution industry?

A. No. This type of under-recovery of fixed costs is not unique to Columbia Gas of Kentucky. This situation has been a continuing challenge to the gas distribution segment of the energy industry as well as to NiSource in each of its gas distribution companies. Energy efficiencies and conservation have adversely affected the financial performance of distribution companies who have billed a volumetric rate to recover fixed delivery costs.

Q. How is the gas distribution industry addressing the problem of the under recovery of fixed costs?

A. The revenue shortfall problem for gas distribution utilities has received much attention from state regulators over the last five years. To effectively mitigate the variability in revenues caused primarily by declining use per customer, regulators have implemented a number of ratemaking solutions, including:

1. Revenue decoupling mechanisms that adjust rates for changes in usage caused primarily by weather and energy conservation;
2. Straight-Fixed Variable rate structures; and
3. Fixed monthly charges that more fully reflect the gas utility's fixed costs of providing delivery service.

Attachment MPB-10 shows which states currently have some kind of revenue decoupling mechanisms in place to address the problem.

Q. Please explain how Columbia's proposed rate design will address the impact of declining use per customer on Columbia's ability to recover its approved margin level?

A. Since virtually all of Columbia's margin consists of fixed costs, and because the Monthly Customer Charge under its proposed SFV rate structure for GSR/GTR customers is designed to eventually recover 100% of those fixed costs, Columbia's ability to recover its Commission-approved level of margin through base revenues no longer will be subject to the ongoing fluctuations in customer usage caused energy conservation, and energy efficiency activities. Of course, Columbia's ability to earn a reasonable rate of return on its investment will continue to be impacted by how well management can control its costs of providing delivery service relative to the levels assumed, and ultimately approved by the Commission, in Columbia's most recently completed base rate case.

Q. Please explain the rationale for proposing a SFV rate design for the GSR/GTR customers.

A. Columbia has determined that it is reasonable and appropriate to collect the proposed revenue requirement for this class from its customers through a SFV rate design. Under a SFV 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. SFV rates are a logical and appropriate extension of collecting all customer-related costs through the utility's monthly customer charge. A utility's customer-related costs do not vary with gas usage; therefore, customer-related costs should be collected through a fixed component of the utility's rate structure.

Substantially all costs that are not classified as customer-related are demand-related, and these costs also do not vary with gas usage. For customers served under these rate schedules, it is not practical to have a separate demand-based charge due to the difficulty in measuring a customer's daily demand.

To mitigate the near-term impact of SFV rates on customers' bills and to allow customers sufficient time to adjust to this new type of rate structure, Columbia has proposed that for the first year after completion of this rate proceeding the current monthly customer charge be increased approximately half-way towards the SFV-based rate level, with the balance of the GSR/GTR revenue requirement collected through the proposed volumetric (i.e., gas consumption) charge. Starting the second year the proposed rates will be in effect, the Company's fixed costs of natural gas delivery service are proposed to be recovered from its GSR/GTR customers through a single, fixed monthly charge.

The proposed volumetric charge is set at a level to collect the balance of the proposed revenue requirement for this class not recovered through the above-described Customer Delivery Charge

Q. Please explain the benefits to Columbia and its customers of a single, fixed monthly charge.

A. There are numerous benefits to Columbia and its customers with a single, fixed monthly bill concept under its proposed SFV rate design. They include:

- Customers don't overpay or underpay each month.
- Addresses intra-class cross subsidization.
- Improved bill stability.
- Achieves bill simplicity and promotes understandability.
- Expectation of fewer bill complaints.
- Matches approved level of revenues with costs.
- Similar pricing to other consumer services.
- Reduces rate case frequency.
- Simplifies revenue forecasts and adjustments.

- Lower annual true-ups for customers on the Columbia's budget billing program.

Q. Is the fixed monthly bill concept familiar to customers?

A. Yes, customers already are accustomed to paying bills for widely utilized consumer services on a flat monthly basis. There are numerous examples of regular consumer services where the service provider structures its fees on a flat monthly basis. These include:

- Local and long distance telephone services
- Cellular telephone services
- Cable television and satellite basic service
- Internet access service
- Home alarm services
- Trash removal services
- Automobile leases and loan payments
- Apartment rent

The pricing of Columbia's gas delivery services using an SFV rate design properly portrays to its customers: (1) the fixed nature of the underlying costs; (2) the delivery-only characteristics of the service; and, (3) the fact that natural gas is the real commodity being purchased via Columbia's gas delivery system.

Q. Under Columbia's proposed SFV rate design, will customers continue to have a financial incentive to pursue energy conservation and energy efficiency measures?

A. Yes. First, the portion of the customer's gas bill represented by Columbia's delivery service charges is small relative to the gas commodity charges incurred by the customer. Currently, as depicted on Attachment MPB-11, the portion of the average residential customer's bill represented by delivery service is only approximately 25% of the total bill. For an average-sized customer on rate schedule GSR (using 69.8 Mcf per year), approximately \$17.20 per month will be shifted from the volumetric charge to the Customer Delivery Charge under the proposed base rates beginning one year after rates go in effect resulting from this case. This is a small amount in contrast to the customer's average bill under proposed rates of approximately \$86 per month (see Attachment MPB-12 Page 3). This very small decrease in the volumetric charge should not materially affect a customer's decision to use more or less gas. Instead, the portion of the customer's bill (approximately 68%) related to Columbia's commodity cost of gas should continue to drive the customer's ongoing gas consumption decisions.

Q. Please explain how Columbia's proposed SFV rate design will impact customers' bills.

A. Columbia's proposed rate design will increase average customer bills in the summer and "shoulder" months, when customer bills are at their lowest levels, and will decrease or moderate the increase in customer bills in the winter months, when bills are at their highest levels. This distinct benefit resulting from a comparison of the initial proposed rates and the proposed SFV rates effective 1 year later is depicted on Attachment MPB-12 Pages 1 and 3.

Q. How will low income GSR/GTR customers be impacted by Columbia's SFV rate design proposal?

A. That will depend upon knowing the specific level of gas consumed by these customers. A reasonable measure of the gas consumption level of low income residential customers served by Columbia is to examine the gas usage data for customers that have received energy assistance through Columbia's energy assistance plan or the federal government's low income home energy assistance plan (LIHEAP) during the test year. These customers are customers with a gross yearly household income at or below 130 percent of the federal poverty level. During Columbia's test year, its average GSR/GTR residential customer (excluding energy assisted customers) consumed approximately 71.2 Mcf per year. In contrast, the average energy assisted residential customer receiving service from Columbia used 76.7 Mcf per year – which is approximately 7.7 percent higher than the average residential customer.

Attached MPB-13 presents an annual bill comparison of present rates to the SFV rate proposed in the second year) for an average residential customer on rate schedule GSR/GTR (excluding those customers who received energy assistance) and an average energy assistance residential customer. Under Columbia's proposed SFV rate design, the low income residential customer will experience an increase in base rates that is approximately $10.29 per year less than the increase in base rates that will be experienced, on average, by all other residential customers on rate schedule GSR/GTR. Therefore, it is clear that Columbia's lower income customers will benefit from its proposed GSR/GTR rate design based on a SFV rate structure.

Q: Do you have a final comment on SFV rate design for the GSR/GTR rate class?

A: Yes, the SFV rate design achieves a number of rate objectives, including: (1) it reflects cost causation; (2) it levelizes the distribution component of customer bills, providing rate certainty; (3) it reduces the revenue deterioration of a utility in the time of reduced consumption: thus, reducing the need for future rate cases; (4) it alleviates the need for a decoupling mechanism which requires frequent controversial reconciliations and weather adjustments; and, (5) it eliminates a utility's natural disincentive to promote energy conservation which, when rates are volume-based, causes revenue erosion.

Q: Does this complete your Prepared Direct Testimony?

A: Yes, it does; however I reserve the right to file rebuttal testimony if necessary.

Attachment MPB-1

COLUMBIA GAS OF KENTUCKY, INC.

DEVELOPMENT OF ALLOCATION FACTORS

DEMAND / COMMODITY METHOD

Direct Assignment

"Direct Assignment" refers to a specific identification and isolation of plant and/or expenses based on Columbia's accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term "direct" immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day Excluding DS - ML

The volumes contained in Factor No. 1 represent the total, non-interrupted tariff demand projected to occur at Columbia's design peak day.

Factor No. 1 was combined and equally weighted with Factor No. 4 to produce composite Factor No. 5.

Factor No. 2 - Design Day Excl. Interruptible Demand

Factor No. 2 uses the same data as Factor No. 1 excluding interruptible demand.

Factor No. 3 - 2" Mains Minimum System

Factor No. 3 was used in the Customer/Demand Study. For a description of Factor No. 3 see the DEVELOPMENT OF ALLOCATION FACTORS, CUSTOMER/DEMAND METHOD.

Factor No. 4 - Throughput Excluding DS - ML

Throughput volumes, including transportation, for the twelve months ending December 31, 2008 were used to develop Factor No. 4. Factor No. 1 was combined and equally weighted with Factor No. 4 to produce composite Factor No. 5.

Factor No. 5 - Composite of Factors No. 1 and No. 4

Factor No. 1 was combined and equally weighted with Factor No. 4 to produce composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending December 31, 2008 were averaged and used to develop Factor No. 6.

Factor No. 7 - Distribution Plant Excluding Other

Factor No. 7 ratios were based on the spread of distribution plant dollars, excluding FERC 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars were aggregated and reduced to percentages to produce Factor No. 7.

Factor No. 8 - Total Plant Account 385

Factor No. 8 ratios were based on the spread of distribution plant Account 385 dollars that were directly assigned by rate class. The directly assigned dollars were aggregated and reduced to percentages to produce Factor No. 8.

Factor No. 9 - Gas Purchased Expense

Factor No. 9 was based on gas cost assigned to each rate schedule using the expected gas cost rate in effect at March 1, 2009. The resulting dollars make up the combined Gas Purchase Expense on page 13 for the following gas purchase accounts:

Account 803 - Gas Field & Trans. Line Purchases

Account 804 - Nat. Gas City Gate Purchases

Account 805 - Other Gas Purchases

Account 806 - Nat. Gas City Gate Purchases

Account 808 - Gas Withdrawn from Storage

Factor No. 10 - Other Distribution Expense - Labor

Factor No. 10 was based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 14 - Distribution Expense Allocation - Labor

Line 3 Account 871 - Distribution Load Dispatch

Line 4 Account 874 - Mains & Services

Line 5 Account 875 - M & R - General

Line 6 Account 876 - M & R - Industrial

Line 7 Account 878 - Meters & House Regulators

Line 8 Account 879 - Customer Installation

Line 14 Account 886 - Structures & Improvements

Line 15 Account 887 - Mains

Line 16 Account 889 - M & R - General

Line 17 Account 890 - M & R - Industrial

Line 18 Account 892 - Services

Line 19 Account 893 - Meters & House Regulators

Factor No. 11 - Other Distribution Expense - Material and Expense

Factor No. 11 was based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 17 - Distribution Expense Allocation - M & E

Line 3 Account 871 - Distribution Load Dispatch

Line 4 Account 874 - Mains & Services

Line 5 Account 875 - M & R - General

Line 6 Account 876 - M & R - Industrial

Line 7 Account 878 - Meters & House Regulators

Line 8 Account 879 - Customer Installation

Line 14 Account 886 - Structures & Improvements

Line 15 Account 887 - Mains

Line 16 Account 889 - M & R - General

Line 17 Account 890 - M & R - Industrial

Line 18 Account 892 - Services

Line 19 Account 893 - Meters & House Regulators

Factor No. 12 - Total Operation and Maintenance Excluding Administrative and General Expense – Labor

Factor No. 12 was based on the spread of dollars to the various classes of customers within the following production, and distribution expense accounts:

Page 13 - Production Expense Allocation - Labor

Line 3 Account 717 – Lique Petro Gas Exp - Labor

Line 9 Account 741 - Structures & Improv. - Labor

Line 11 Account 742 - Production Equipment - Labor

Line 18 Account 807 - Other Purchased Gas - Labor

Page 16 - Distribution Allocation - Labor

Line 7 Total Distribution Expenses

Factor No. 13 - O&M Excluding Gas Purchase, Uncollectible Accounts and A&G - M&E

Factor No. 13 was based on the spread of dollars to the various classes of customers within the following production, and distribution expense accounts:

Page 13 - Production Expense Allocation

Line 4 Account 717 - Lique Petro Gas Exp - M&E

Line 5 Account 723 - Lique Petro Gas Process - M&E

Line 6 Account 728 - Liquified Petroleum Gas

Line 10 Account 741 - Structures & Improv. - M&E

Line 12 Account 742 - Production Equipment - M&E

Line 19 Account 807 - Other Purchase Gas - M&E

Line 20 Account 812 - Gas Used in Operations

Page 19 - Distribution Expense Allocation - M&E

Line 7 Total Distribution Expenses - M&E (excl. Acct. 904)

Factor No. 14 - Accounts 376 Mains and 380 Services

Factor No. 14 reflects the relationship based on the spread of dollars in Accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account were aggregated and reduced to percentages to produce Factor No. 14.

Factor No. 15 - Account 380 Services

Services were assigned to the various customer classes based on the actual assignment of services by size and kind to each customer. From Columbia's DIS, the actual number of services were identified and counted by size for each rate class. Then from Columbia's property records an average unit cost was determined for services of three inches and smaller and over three inches in size. The average unit cost for services three inches and smaller is $416.48 and $1,102.09 for services larger than three inches. The number of services for each size category under each rate class was then multiplied by their respective average unit cost. The total cost per rate class was then divided by the total cost for all rate class to arrive at the final allocation percentages.

The actual service line assignment methodology took into account the differences in costs that the individual customers caused Columbia to incur. It utilized the actual size of the service installed for each customer. Further, it recognized the quantity of shared services, or services that serve more than one customer. This was accomplished with a detailed examination of Columbia's property records and an inventory of service lines installed on customer premises.

Factor No. 16 - Accounts 381 Meters

Meters were assigned to the various classes of customers based on an actual inventory of meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size increases. Individual installed meters for residential, small commercial, and small industrial customers were identified on Columbia's DIS and summarized by the four pressure groups. The capitalized property investment for the four pressure groups was divided by the inventory of installed meters to develop a cost per meter for each group of meters. The costs per meter were multiplied by the inventory of installed meters to determine the investment for each customer class. Meter investment for the commercial and industrial customers was further broken down between the various rate classes based on the number of customers. The ratios developed for Account 381 Meters were then used to assign the investment in Account 382 Meter Installations, 383 House Regulators and 384 House Regulator Installations since these costs are incurred in direct association with meters.

Factor No. 17 - Direct Plant Account 385 Industrial Measuring & Regulating Station Equipment

Individual measuring stations are identified on Columbia's plant records by rate class. The investment, so segregated, was aggregated and reduced to percentages to produce Factor No.17.

Factor No. 18 - Account 376 Mains

Factor No. 18 reflects the relationship based on the spread of dollars in Account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for classes that could not be directly assigned. The dollars were aggregated and reduced to percentages to produce Factor No. 18.

Factor No. 19 - Total Plant

Factor No. 19 ratios were based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars were aggregated and reduced to percentages to produce Factor No. 19.

COLUMBIA GAS OF KENTUCKY, INC.

DEVELOPMENT OF ALLOCATION FACTORS

CUSTOMER / DEMAND METHOD

Factor No. 3 - 2" Mains Minimum System

Factor No. 3 is a composite weighting between a minimum system investment that is allocated on a customer basis versus the remainder of the Mains Account that is allocated using design day volumes.

Plant records were used as the basis for the minimum system study. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor. See page 3 for the development of the Customer and Demand component factors.

The final step in developing Factor No. 3 allowed for each of the component factors described above (number of customers and design day volumes), to be weighted by their respective ratios to the various customer classes (see page 3).

Factor No. 3 - Allocation Development

Assume that two inch pipe, the most common pipe size, is the minimum size needed to provide service.

All calculations are based on Account 376, 101-1000 pipe data only. Does not include valves, anodes, etc.

(2" pipe cost) $23,549,883	÷	(2" pipe quantity) 4,531,539 feet	=	(2" pipe cost per foot) $5.1969
(2" cost per foot) $5.1969	X	(total pipe quantity) 13,715,429 feet	=	(cost of minimum system) $71,277,713
(cost of minimum system) $71,277,713	÷	(total pipe cost) $116,243,057	=	(customer component factor) **.6132**
1.0000 - .6132 = **.3868** demand component factor				

COLUMBIA GAS OF KENTUCKY, INC.
CUSTOMER / DEMAND COMPONENT
FACTOR 3
AS OF DECEMBER 31, 2008

(A)	CUSTOMERS (B)	% (C)	CUSTOMER COMPONENT FACTOR (D=C x 0.7078%)	DESIGN DAY VOLUMES (E)	DESIGN DAY % (F)	DEMAND COMPONENT FACTOR (G=F x 0.2922)	TOTAL (H=D + G)
GS – RES	124,717	89.581%	54.930%	144,700	41.930%	16.219%	71.149%
GS – OTHER	14,424	10.360%	6.353%	137,200	39.757%	15.379%	21.732%
IUS	2	0.001%	0.001%	300	0.087%	0.034%	0.035%
DS-ML/SC–	0	0.000%	0.00%	0000	0.000%	0.000%	0.00%
DS/IS	79	0.057%	0.035%	62,900	18.227%	7.050%	7.085%
TOTAL	139,222	100.000%	61.318%	345,100	100.000%	38.682%	100.000%

COLUMBIA GAS OF KENTUCKY, INC.
FACTOR SELECTION AND RATIONALE
DEMAND / COMMODITY STUDY

ALLOCATION STUDY – D/C STUDY

OPERATING EXPENSES - PRODUCTION EXPENSES - PAGE 13

Accounts 717 through 742

Liquefied Petroleum Gas expenses are allocated using Factor No. 2 - Design Day Excluding Transportation (MCF) since Liquefied Petroleum Gas is part of Columbia's supply mix for its tariff sales customers.

OPERATING EXPENSES - OTHER GAS SUPPLY EXPENSES - PAGE 19

Accounts 803, 804, 805, 806 and 808 (Cost of Gas at the City Gate)

Natural Gas Purchased Expenses were directly assigned to match the amount of gas cost embedded in Operating Revenue by rate class.

Accounts 807 and 812

Other Gas Purchased Expenses and Gas Used in Company Operations were allocated using Factor No. 9 - Gas Purchased Expense, which was based on actual gas purchased expenses.

DISTRIBUTION EXPENSES - LABOR - PAGE 14 AND M&E - PAGE 17

Accounts 870, 880, 881, 885 and 894

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor Nos. 10 (Labor) and 11 (M&E), the aggregate factors of all other distribution accounts, since these costs benefit customers in relation to the way all other distribution costs provide benefit.

Account 871

Distribution Load Dispatch expenses were allocated on Factor No. 4 - Throughput, since these are costs incurred monitoring and directing the flow of gas through the distribution system.

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 - Allocated Plant Investment of Mains and Services combined.

Account 887

Mains maintenance expense was allocated using Factor No. 18, which reflects the spread of Account 376 Mains dollars among all customer classes, since plant and expense functions are directly related.

Accounts 875, 886 and 889

Factor No. 18 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct association with mains.

Accounts 876 and 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 8 - Total Account 385 - since these costs were incurred in direct association with the stations in Account 385.

Account 892

Expenses for Services were allocated using Factor No. 15 which was based on a weighted customer factor as explained in the DEVELOPMENT OF ALLOCATION FACTORS, DEMAND/COMMODITY METHOD and in the direct testimony of Columbia witness Mark Balmert. The weighted customer factor is derived by an actual detailed examination of actual inventories of installed Services unique to Columbia and represents virtually a direct assignment of costs to the various customer groups.

Accounts 878, 879 and 893

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in the DEVELOPMENT OF ALLOCATION FACTORS, DEMAND/COMMODITY METHOD and in the direct testimony of Columbia witness

Mark Balmert. This methodology represents virtually a direct assignment of costs to the various customer groups. Expenses for House Regulators and Customer Installations were allocated using Factor No. 16 since these costs are incurred in direct association with the meters.

CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES EXPENSES - LABOR - PAGES 15 AND 16 AND M&E - PAGES 18 AND 19

Accounts 901 - 903, 904, and 905 - 916, Distribution Expense Portion of Accounts 921, 931, and 935

Meter Reading/Records/Collection/Customer Assistance, Uncollectibles and related costs were allocated on Factor No. 6 - Average Number of Customers. Costs incurred throughout the Customer Accounts function are, quite directly, related to the number of customers served.

ADMINISTRATIVE AND GENERAL EXPENSES - LABOR - PAGE 16 AND M&E - PAGE 19

Accounts 920 through 935

General Office expenses, and to a lesser degree, District and Local Office expenses in this function classification, plus company-wide expenses such as Injuries and Damages, Insurance, total Company Employee Benefits and Regulatory Commission Expense were all allocated using Factor No. 12 for Labor and Factor No. 13 for M&E - Total Operation & Maintenance Excluding Gas Purchased and Administrative and General Expenses. These costs are regarded as overheads to the entire company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. M&E for accounts

925 and 926 are allocated on Factor No. 12 instead of 13 because of direct cost causation of labor to these accounts.

OPERATING REVENUE AT CURRENT RATES - PAGE 12

Accounts 487, 488, 493 and 495

Bad check charges, rents and other charges were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Delayed Payments were allocated based on average customers excluding residential since they are exempt from this charge. Revenue included in account 495 for off--system sales was assigned directly to its own category.

TAXES OTHER THAN INCOME - PAGE 21

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 7 - Distribution Plant excluding Other due to a direct relationship with Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly, have been allocated based on Factor No. 12 - Total Operation and Maintenance Excluding Administrative and General - Labor.

FEDERAL AND STATE INCOME TAX - PAGES 22 THROUGH 25

Non-Deductible Employee Expense are A&G labor expenses that are deductions to Federal Income Taxes and, therefore, are allocated on the same allocation factor, No. 12 - Other Distribution expense - Labor as A&G expenses are.

Excess Book Depreciation over Tax Depreciation were allocated using Factor No. 19 since they are directly associated with the costs of virtually all Plant in Service accounts.

In calculating the Federal and State income taxes for each rate class, the effective Federal and State income tax rates were used. The effective rates were developed on the total Company's taxable income divided by Columbia's income tax expense. By using the effective rate, the impact of the graduated Federal and State tax rate schedules is assigned to each rate class.

RATE BASE SUMMARY - PAGE 26

Accounts 190, 255, 282 and 283

Accumulated deferred income taxes and the 1962 - 1969 investment tax credit were allocated using Factor No. 19 - Total Plant, because of their direct relationship to plant investment.

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 7 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

Account 164

Gas Stored Underground - FSS were allocated based on Factor No. 2 - Design Day Excluding Transportation (MCF) since these volumes supply all but transportation customers for design day.

DEPRECIATION AND AMORTIZATION EXPENSE - PAGES 10 THROUGH 11

Depreciation and amortization expense was allocated by Gas Plant Account on the same allocations as the Gross Original Cost.

GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 - PAGES 4 THOUGH 7

INTANGIBLE PLANT - PAGE 4 (101-106). PAGE 6 (107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Other, Factor No. 7, due to its indirect relationship with all other plant.

PRODUCTION PLANT - PAGE 4 (101-106). PAGE 6 (107)

Accounts 304 through 311

Production Plant was allocated using Factor No. 2 - Design Day Excluding Transportation (MCF) since the function of the plant's gas volumes are to supplement a supply mix that benefits all sales customers.

DISTRIBUTION PLANT - PAGE 4-5 (101-106), PAGE 6-7 (107)

Accounts 374, 375 (except 375.60, 375.70 and 375.71), 376, 378 and 379

Land, Land Rights, Mains and Measuring and Regulating Equipment, not directly assigned, were allocated using composite Factor No. 5, since the customers' benefits from these investments are equally related to their annual throughput requirements (Factor No. 4) and design day capacity needs (Factor No. 1).

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 8 since these structures house measuring and regulating stations serving large commercial and industrial customers only.

Accounts 375.70 and 375.71

Other distribution structures and improvements were allocated on the basis of Distribution Plant excluding Other, due to their direct relationship with all other gas plant accounts.

Account 380

Services were allocated using Factor No. 15 which was based on a weighted customer factor as explained in the DEVELOPMENT OF ALLOCATION FACTORS, DEMAND/COMMODI Y METHOD and my direct testimony. The weighted customer factor is derived by an actual detailed examination of actual inventories of installed Services unique to Columbia and represents virtually a direct assignment of costs to the various customer groups.

Accounts 381, 382, 383 and 384

Meters and Meter Installations, House Regulators and House Regulator Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in the DEVELOPMENT OF ALLOCATION FACTORS, DEMAND/COMMODITY METHOD and in my direct testimony. This methodology represents virtually a direct assignment of costs to the various customer groups. Accounts 382, 383, and 384 were allocated using Factor No. 16 since these costs are incurred in direct association with the meters.

Account 385

Industrial measuring and regulating stations were allocated using Factor No. 17 which was based on a review of Columbia's records as explained in the DEVELOPMENT OF ALLOCATION FACTORS, DEMAND/COMMODITY METHOD and in my direct testimony. Measuring stations were segregated by rate class. This methodology represents virtually a direct assignment of costs to the various customer groups.

DISTRIBUTION PLANT ACCOUNT 387 - OTHER AND GROSS GENERAL PLANT - GENERAL LEDGERS 101, 106 AND 107 - PAGES 5 AND 7

Accounts 387 through 398

Other Equipment and General Plant investments were allocated on the basis of total Distribution Plant excluding Other Equipment, Factor No. 7, due to the indirect relationship with all other gas plant.

RESERVE FOR DEPRECIATION - PAGES 8 AND 9

Depreciation Reserve was calculated on an account by account basis using the same allocation factors that were used to allocate all gross plant accounts.

COLUMBIA GAS OF KENTUCKY, INC.
FACTOR SELECTION AND RATIONALE
CUSTOMER / DEMAND STUDY

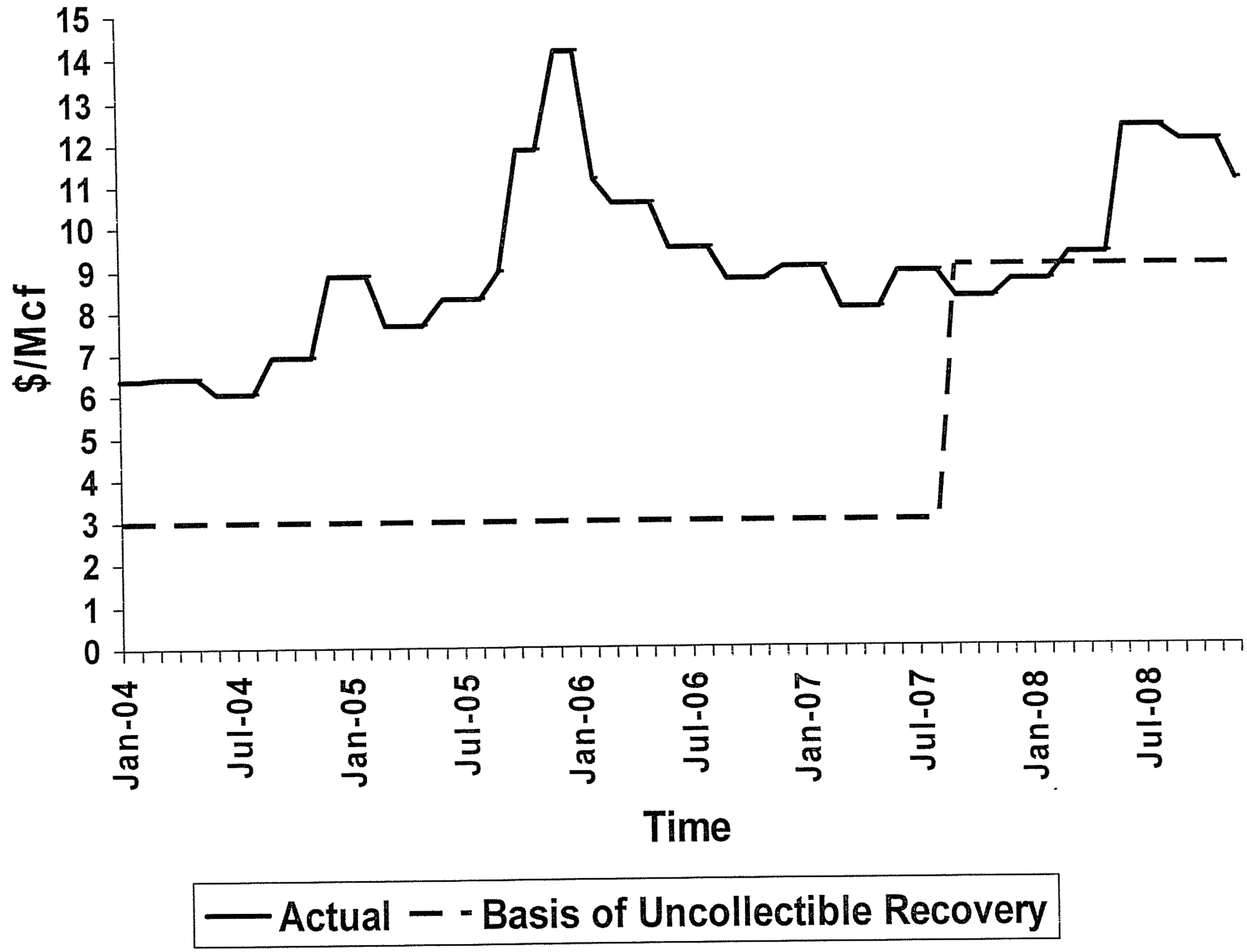
ALLOCATION STUDY – C/D STUDY
GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 - PAGES 6 AND 7

DISTRIBUTION PLANT - PAGE 6

Accounts 374, 375 (except 375.60, 375.70 and 375.71), 376, 378 and 379

Land, Land Rights, Mains and Measuring and Regulating Equipment, not directly assigned, were allocated using Factor No. 3. Factor No. 3 was developed from Account 376 - Mains and is a composite, equal weighing between a minimum system investment that is allocated on a customer basis verses the remainder of the mains account that is allocated using design day volumes. Factor No. 3 is based on the concept that a large portion of the Mains must be in place just to connect the customers to the gas supply and is customer related. The remainder of the piping system was designed to handle peaking requirements and is demand related.

Columbia Gas of Kentucky
Commodity EGC Rates



Columbia Gas of Kentucky, Inc.
Commodity EGC Rates
For the Years 2004 through 2008

Month (1)	Year (2)	Rate (3) ($/Mcf)	Month (1)	Year (2)	Rate (3) ($/Mcf)
Jan	2004	6.3973	Jul	2006	9.4889
Feb	2004	6.3973	Aug	2006	9.4889
Mar	2004	6.4285	Sep	2006	8.7472
Apr	2004	6.4285	Oct	2006	8.7472
May	2004	6.4285	Nov	2006	8.7472
Jun	2004	6.0469	Dec	2006	9.0113
Jul	2004	6.0469	Jan	2007	9.0113
Aug	2004	6.0469	Feb	2007	9.0113
Sep	2004	6.9068	Mar	2007	8.0468
Oct	2004	6.9068	Apr	2007	8.0468
Nov	2004	6.9068	May	2007	8.0468
Dec	2004	8.8517	Jun	2007	8.9201
Jan	2005	8.8517	Jul	2007	8.9201
Feb	2005	8.8517	Aug	2007	8.9201
Mar	2005	7.6625	Sep	2007	8.2708
Apr	2005	7.6625	Oct	2007	8.2708
May	2005	7.6625	Nov	2007	8.2708
Jun	2005	8.2954	Dec	2007	8.6971
Jul	2005	8.2954	Jan	2008	8.6971
Aug	2005	8.2954	Feb	2008	8.6971
Sep	2005	8.9457	Mar	2008	9.3328
Oct	2005	11.8175	Apr	2008	9.3328
Nov	2005	11.8175	May	2008	9.3328
Dec	2005	14.1464	Jun	2008	12.3060
Jan	2006	14.1464	Jul	2008	12.3060
Feb	2006	11.1184	Aug	2008	12.3060
Mar	2006	10.5575	Sep	2008	11.9881
Apr	2006	10.5575	Oct	2008	11.9881
May	2006	10.5575	Nov	2008	11.9881
Jun	2006	9.4889	Dec	2008	11.0603

Basis of Uncollectible Recovery in Base Rates

Year (1)	Uncollectible Rate Basis Case No. (2)	EGC Commodity Rate Basis Rate (3) ($/Mcf)	EGC Rate Basis Eff. Date (4)
2004	2002-00145	2.9495	3/02
2005	2002-00145	2.9495	3/02
2006	2002-00145	2.9495	3/02
1/07 - 8/07	2002-00145	2.9495	3/02
9/07 - 12/07	2007-00008	9.0113	12/06
2008	2007-00008	9.0113	12/06

Account 904 Expense incurred on Commodity Gas Cost Recovery

Month (1)	Year (2)	Account 904 Expense CE 8510 (DIS Billed) (3) ($)	Actual DIS Billed Revenue (4) ($)	Effective Uncollectible Rate (5=3/4)	EGC Commodity Rate (6) ($/Mcf)	EGC Billed Volumes (7) (Mcf)	Uncollectible Expense Resulting From EGC Commodity (8=5*6*7) ($)
Jan	2004	145,000.00	23,314,012.13	0.00621944	6.3973	1,996,483.8	79,435.35
Feb	2004	121,000.00	24,902,768.30	0.00485890	6.3973	2,175,437.4	67,620.95
Mar	2004	77,000.00	17,157,456.59	0.00448784	6.4285	1,440,585.1	41,560.99
Apr	2004	62,999.99	11,581,871.26	0.00543953	6.4285	966,286.3	33,789.12
May	2004	31,000.00	5,443,681.74	0.00569468	6.4285	427,250.9	15,640.91
Jun	2004	38,982.00	2,887,929.33	0.01349825	6.0469	214,342.5	17,495.19
Jul	2004	167,000.00	2,564,118.47	0.06512960	6.0469	185,761.1	73,158.70
Aug	2004	182,000.00	2,666,029.29	0.06826632	6.0469	185,184.4	76,444.05
Sep	2004	330,000.00	2,492,667.31	0.13238830	6.9068	194,411.2	177,765.62
Oct	2004	30,000.00	3,186,669.47	0.00941422	6.9068	268,325.1	17,447.07
Nov	2004	77,000.00	5,569,483.19	0.01382534	6.9068	529,444.0	50,556.00
Dec	2004	(74,636.20)	15,431,893.00	(0.00483649)	8.8517	1,294,104.8	(55,402.13)
Total Year		1,187,345.79	117,198,580.08			9,877,616.6	595,511.82
Jan	2005	217,000.00	22,925,858.99	0.00946529	8.8517	1,871,819.2	156,828.33
Feb	2005	205,000.00	22,868,115.35	0.00896445	8.8517	1,882,701.7	149,393.55
Mar	2005	155,000.00	18,466,103.64	0.00839376	7.6625	1,706,012.8	109,725.94
Apr	2005	108,000.00	11,869,665.21	0.00909882	7.6625	1,049,220.0	73,151.31
May	2005	69,000.00	6,281,253.99	0.01098507	7.6625	540,459.1	45,492.12
Jun	2005	40,000.00	3,643,629.01	0.01097807	8.2954	267,633.3	24,372.69
Jul	2005	(55,000.00)	2,786,045.67	(0.01974124)	8.2954	191,098.1	(31,294.51)
Aug	2005	30,000.00	2,647,154.88	0.01133292	8.2954	234,620.6	22,056.94
Sep	2005	52,000.00	2,564,100.80	0.02028001	8.9457	198,983.1	36,099.29
Oct	2005	45,000.00	3,523,896.34	0.01276996	11.8175	283,894.2	42,842.19
Nov	2005	88,000.00	10,891,592.37	0.00807963	11.8175	779,298.1	74,408.18
Dec	2005	31,000.00	27,851,882.52	0.00111303	14.1464	1,770,410.6	27,875.77
Total Year		985,000.00	136,319,298.77			10,776,150.8	730,951.80
Jan	2006	214,000.00	34,214,084.19	0.00625473	14.1464	2,049,048.8	181,303.76
Feb	2006	181,000.00	23,734,089.12	0.00762616	11.1184	1,747,699.0	148,188.62
Mar	2006	154,000.00	20,431,656.91	0.00753732	10.5575	1,576,672.2	125,464.09
Apr	2006	101,000.00	13,347,054.04	0.00756721	10.5575	1,006,995.8	80,449.72
May	2006	51,000.00	6,604,874.59	0.00772157	10.5575	477,575.9	38,932.21
Jun	2006	39,000.60	4,010,678.21	0.00972419	9.4889	297,609.4	27,460.97
Jul	2006	28,000.00	2,922,156.52	0.00958196	9.4889	194,010.1	17,639.84
Aug	2006	27,000.00	3,010,415.88	0.00896886	9.4889	212,954.1	18,123.38
Sep	2006	325,000.00	2,888,281.03	0.11252368	8.7472	222,648.4	219,145.50
Oct	2006	18,000.00	4,358,804.51	0.00412957	8.7472	393,794.1	14,224.70
Nov	2006	42,000.00	10,190,988.36	0.00412129	8.7472	990,580.2	35,710.17
Dec	2006	(49,000.00)	14,988,017.57	(0.00326928)	9.0113	1,414,362.7	(41,667.78)
Total Year		1,131,000.60	140,701,100.93			10,583,950.7	864,975.18

Account 904 Expense incurred on Commodity Gas Cost Recovery

Month (1)	Year (2)	Account 904 Expense CE 8510 (DIS Billed) (3) ($)	Actual DIS Billed Revenue (4) ($)	Effective Uncollectible Rate (5=3/4)	EGC Commodity Rate (6) ($/Mcf)	EGC Billed Volumes (7) (Mcf)	Uncollectible Expense Resulting From EGC Commodity (8=5*6*7) ($)
Jan	2007	201,000.00	17,944,218.84	0.01120138	9.0113	1,653,888.5	166,941.84
Feb	2007	216,000.00	25,071,977.81	0.00861520	9.0113	2,509,391.9	194,814.51
Mar	2007	178,000.00	15,991,445.77	0.01113095	8.0468	1,915,940.9	171,608.01
Apr	2007	133,000.00	8,597,590.01	0.01546945	8.0468	967,758.6	120,466.17
May	2007	(43,000.00)	5,140,540.54	(0.00836488)	8.0468	551,727.6	(37,137.07)
Jun	2007	52,000.00	3,078,631.65	0.01689062	8.9201	281,351.4	42,390.10
Jul	2007	(255,000.00)	2,618,583.70	(0.09738089)	8.9201	217,501.4	(188,932.00)
Aug	2007	30,000.00	2,757,309.63	0.01088017	8.9201	237,631.8	23,062.69
Sep	2007	(214,000.00)	3,344,697.25	(0.06398187)	8.2708	193,413.5	(102,350.80)
Oct	2007	165,000.53	3,965,633.80	0.04160761	8.2708	257,762.2	88,703.25
Nov	2007	(11,000.00)	9,636,484.62	(0.00114150)	8.2708	747,075.2	(7,053.23)
Dec	2007	18,000.00	18,729,341.29	0.00096106	8.6971	1,473,876.3	12,319.30
Total Year		470,000.53	116,876,454.91			11,007,319.3	484,832.77
Jan	2008	153,000.00	26,522,667.25	0.00576865	8.6971	2,103,795.6	105,548.53
Feb	2008	75,000.00	27,613,039.85	0.00271611	8.6971	2,221,423.6	52,475.09
Mar	2008	97,000.00	24,118,552.37	0.00402180	9.3328	1,931,765.7	72,508.16
Apr	2008	160,000.00	14,580,435.27	0.01097361	9.3328	1,101,689.2	112,828.96
May	2008	66,000.00	7,564,274.19	0.00872523	9.3328	524,695.2	42,726.36
Jun	2008	231,000.00	5,674,584.52	0.04070783	12.3060	292,609.9	146,583.09
Jul	2008	336,000.00	4,490,976.10	0.07481670	12.3060	223,048.8	205,359.76
Aug	2008	374,000.00	4,265,043.28	0.08768961	12.3060	208,435.0	224,923.95
Sep	2008	(27,000.00)	4,457,351.34	(0.00605741)	11.9881	217,935.2	(15,825.76)
Oct	2008	412,000.00	5,150,707.14	0.07998902	11.9881	267,486.0	256,496.70
Nov	2008	(54,000.00)	12,453,022.75	(0.00433630)	11.9881	738,848.5	(38,408.30)
Dec	2008	87,000.00	27,029,303.86	0.00321873	11.0603	1,816,655.4	64,673.15
Total Year		1,910,000.00	163,919,957.92			11,648,388.1	1,229,889.69

Account 904 Expense Recovered on Commodity Gas Cost Recovery through Base Rates

Year (1)	Uncollectible Rate Basis Rate (2)	Uncollectible Rate Basis Case No. (3)	EGC Commodity Rate Basis Rate (4) ($/Mcf)	EGC Rate Basis Eff. Date (5)	Uncollectible Recovery Rate Basis (6) ($/Mcf)	EGC Billed Volumes (Mcf) (7) (Mcf)	Uncollectible Recovery (8=6*7) ($)
2004	0.00835866	2002-00145	2.9495	3/02	0.0247	9,877,616.6	243,977.13
2005	0.00835866	2002-00145	2.9495	3/02	0.0247	10,776,150.8	266,170.92
2006	0.00835866	2002-00145	2.9495	3/02	0.0247	10,583,950.7	261,423.58
1/07 - 8/07	0.00835866	2002-00145	2.9495	3/02	0.0247	8,335,192.1	205,879.24
9/07 - 12/07	0.01163918	2007-00008	9.0113	12/06	0.1049	2,672,127.2	280,306.14
2007						11,007,319.3	486,185.38
2008	0.01163918	2007-00008	9.0113	12/06	0.1049	11,648,388.1	1,221,915.91

Columbia Gas of Kentucky, Inc.
Determination of Uncollectible Recovery on Commodity Gas Cost Recovery
For the Years 2004 through 2008

Recovery of Uncollectible Accounts on Commodity Gas Cost Recovery Summary

Month (1)	Year (2)	Uncollectible Expense Resulting From EGC Commodity (3)	Base Rate Uncollectible Recovery (4)	Actual Over(Under) Recovery (5=4-3)
	2004	595,511.82	243,977.13	(351,534.69)
	2005	730,951.80	266,170.92	(464,780.88)
	2006	864,975.18	261,423.58	(603,551.60)
	2007	484,832.77	486,185.38	1,352.61
	2008	1,229,889.69	1,221,915.91	(7,973.78)
Total		3,906,161.26	2,479,672.92	(1,426,488.34)

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.	DESCRIPTION	Adjusted Volumes (1) MCF	Revenue @ Current Rates (2) $	Proposed Increase (3) $	Revenue @ Proposed Rates (4) $	Proposed Increase (5=3/2) %
	Gas Service Revenues					
1	GSR/GTR Residential	8,821,212.6	$99,982,884	$9,927,831	$109,910,715	9.93%
2	GSO/GTO/GDS	6,038,277.6	57,346,200	1,150,067	58,496,267	2.01%
3	DS/SAS	8,182,300.3	4,451,506	66,929	4,518,435	1.50%
4	IUS	19,134.0	211,101	10,039	221,140	4.76%
5	IN3	1,536.8	615	0	615	0.00%
6	IN4	112.2	62	0	62	0.00%
7	IN5	721.2	433	0	433	0.00%
5	G1C	6,675.8	78,443	0	78,443	0.00%
6	G1R	2,390.1	32,835	0	32,835	0.00%
7	LG2 Residential	633.9	222	0	222	0.00%
8	LG2 Commercial	938.2	328	0	328	0.00%
9	LG3 Residential	482.8	176	0	176	0.00%
10	LG4 Residential	266.5	107	0	107	0.00%
11	DS3	213,976.0	22,709	0	22,709	0.00%
12	FX1	305,721.5	45,564	0	45,564	0.00%
13	FX2	5,202.2	7,999	0	7,999	0.00%
14	FX4	52,333.0	24,247	0	24,247	0.00%
15	FX5	5,633,272.0	492,547	0	492,547	0.00%
16	FX6	346,158.0	32,771	0	32,771	0.00%
17	FX7	519,685.0	197,160	0	197,160	0.00%
18	FX8	29,145.0	23,173	0	23,173	0.00%
19	SC2	671,369.0	163,829	0	163,829	0.00%
20	SC3	4,145,865.0	761,882	0	761,882	0.00%
21	Other Gas Department Revenue					
22	Acct. 487 Forfeited Discounts		192,713	265,020	457,733	
23	Acct. 488 Miscellaneous Service Revenue		147,314	145,845	293,159	
24	Acct. 495 Non-Traditional Sales		0	0	0	
25	Acct. 495 Prior Yr. Rate Refund - Net.		0	0	0	
26	Acct. 495 Other Gas Revenues - Other		343,888	0	343,888	
27	Total Gas Service Revenues	34,997,408.7	$164,560,706	$11,565,731	$176,126,437	7.03%

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	**GSR/GTR Rate Design**								
2	Total Revenue @ Proposed Rates				109,910,715				
3 Less:	Gas Cost Revenue				69,092,389				
4 Less:	Gas Cost Uncollectible Charge [1]		6,825,692	0.0964	657,997	0			657,997
5 Less:	EAP Revenue				467,903				
6 Less:	Administrative Charge Revenue				0				
7 Less:	Customer Delivery Charge Revenue	1,496,096		**17.92**	26,810,040	13,913,693		9.30	12,896,347
8	Net Volumetric Base Revenue				12,882,386				
9	All Gas Consumed		8,821,212.6	**1.4604**	12,882,499	16,508,899		1.8715	(3,626,400)
10	Total					30,422,592			9,927,944
11	**GSO/GTO/GDS Rate Design**								
12	Total Revenue @ Proposed Rates				58,496,267				
13 Less:	Gas Cost Revenue				42,366,372				
14 Less:	Gas Cost Uncollectible Charge [1]		4,185,408	0.0964	403,473	0			403,473
15 Less:	EAP Revenue				0				
16 Less:	Administrative Charge Revenue	313		**55.90**	17,497	17,497		55.90	0
17 Less:	Customer Charge Revenue	173,017		**28.28**	4,892,081	4,145,487		23.96	746,594
18	Net Volumetric Base Revenue				10,816,844				1,150,067
19 Less:	First 50 Mcf		2,069,388.4	**1.8715**	3,872,860	3,872,860	0.358039785	1.8715	(0)
20	Next 350 Mcf		2,327,287.3	**1.8153**	4,224,725	4,224,725	0.390569074	1.8153	0
21	Next 600 Mcf		838,014.4	**1.7296**	1,449,430	1,449,430	0.133997472	1.7296	0
22	Over 1,000 Mcf		803,587.5	**1.5802**	1,269,829	1,269,829	0.117393669	1.5802	0
23	Total		6,038,277.6		10,816,844	10,816,844	1.000000000		1,150,067

[1] See MPB-6 Sheet 3.

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	**DS/SAS Rate Design**								
2	Total Revenue @ Proposed Rates				4,518,435				
3 Less:	Gas Cost Revenue				0				
4 Less:	Gas Cost Uncollectible Charge [1]		0	0.0964	0	0			0
5 Less:	EAP Revenue				0				
6 Less:	Customer Charge Revenue	862		**620.18**	534,593	467,665		547.37	66,929
7 Less:	Administrative Charge Revenue	862		**55.90**	48,186	48,186		55.90	0
8	Net Volumetric Base Revenue				3,935,656				66,929
9	First 30,000 Mcf		6,083,909.3	**0.5467**	3,326,073	3,326,073	0.845112830	0.5467	(0)
10	Over 30,000 Mcf		2,098,391.0	**0.2905**	609,583	609,583	0.154887170	0.2905	0
11	Total		8,182,300.3		3,935,656	3,935,656	1.000000000		66,929
12	**DS3 (Mainline) Customer Charge Rate Design Change**								
13	Total Revenue @ Proposed Rates				22,709				
14 Less:	Gas Cost Revenue				0				
15 Less:	Gas Cost Uncollectible Charge [1]		0	0.0964	0	0			0
16 Less:	EAP Revenue				0				
17 Less:	Customer Charge Revenue	17		**200.00**	3,400	3,400		200.00	0
18 Less:	Administrative Charge Revenue	17		**55.90**	950	950		55.90	(0)
19	Net Volumetric Base Revenue				18,359				(0)
20	All Gas Consumed		213,976.0	**0.0858**	18,359	18,359		0.0858	(0)
21	Total								(1)
22	**IUS Rate Design**								
23	Total Revenue @ Proposed Rates				221,140				
24 Less:	Gas Cost Revenue				193,682				
25 Less:	Gas Cost Uncollectible Charge [1]		19,134	0.0964	1,845	0			1,845
26 Less:	EAP Revenue				0				
27 Less:	Administrative Charge Revenue				0				
28 Less:	Customer Charge Revenue	24		**331.50**	7,956	6,120		255.00	1,836
29	Net Volumetric Base Revenue				17,657				3,681
30	All Gas Consumed		19,134.0	**0.8729**	16,702	11,299		0.5905	5,403
31	Total		19,134.0		16,702	11,299			9,084

[1]	**Gas Cost Uncollectible Charge to GCA Customers**	
	Expected Gas Cost Commodity Rate as of March 1, 2009 ($/Mcf)	6.8373
	Uncollectible Expense Accrual Rate (See Schedule D-2.1 Sheet 5)	1.410552%
	Proposed Rate / Mcf	**0.0964**

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.			Reference	Detail ($)	Amount ($)
1		**Change in Forfeited Discounts Revenue**			
2		Test Year Forfeited Discounts (Account 487)	Schedule M-2.1		192,713.00
3		Test Year Revenue Subject to Late Payment Penalties:			
4	G1C	LG&E Commercial	Schedule M-2.1	76,888.46	
5	GSO	General Service - Commercial	Schedule M-2.1	59,683,440.58	
6	GSO	General Service - Industrial	Schedule M-2.1	2,355,847.53	
7	IUS	Intrastate Utility Service - Wholesale	Schedule M-2.1	254,639.38	
8	GTO	GTS Choice - Commercial	Schedule M-2.1	3,595,137.38	
9	GTO	GTS Choice - Industrial	Schedule M-2.1	64,589.67	
10	DS	GTS Delivery Service - Commercial	Schedule M-2.1	1,020,173.08	
11	DS	GTS Delivery Service - Industrial	Schedule M-2.1	3,435,275.12	
12	GDS	GTS Grandfathered Delivery Service - Commercial	Schedule M-2.1	434,838.25	
13	GDS	GTS Grandfathered Delivery Service - Industrial	Schedule M-2.1	204,801.06	
14	DS3	GTS Main Line Service - Industrial	Schedule M-2.1	22,709.43	
15	FX1	GTS Flex Rate - Commercial	Schedule M-2.1	136,239.48	
16	FX2	GTS Flex Rate - Industrial	Schedule M-2.1	8,079.95	
17	FX4	GTS Flex Rate - Industrial	Schedule M-2.1	24,257.89	
18	FX5	GTS Flex Rate - Industrial	Schedule M-2.1	492,547.14	
19	FX6	GTS Flex Rate - Industrial	Schedule M-2.1	32,771.16	
20	FX7	GTS Flex Rate - Industrial	Schedule M-2.1	197,160.49	
21	FX8	GTS Flex Rate - Industrial	Schedule M-2.1	20,647.13	
22	SAS	GTS Special Agency Service	Schedule M-2.1	31,680.71	
23	SC2	GTS Special Rate - Industrial	Schedule M-2.1	157,598.52	
24	SC3	GTS Special Rate - Industrial	Schedule M-2.1	719,002.12	
25	Total				72,968,324.53
26		Ration of Late Payment Penalties to Total Revenue	Line 2 / Line 25		0.002641050
27		Proposed Revenue Subject to Late Payment Penalties:			
28		GSR/GTR Residential	MPB-6 Page 1	109,910,715	
29		GSO/GTO/GDS	MPB-6 Page 1	58,496,267	
30		DS/SAS	MPB-6 Page 1	4,518,435	
31		IUS	MPB-6 Page 1	221,140	
32		G1C	MPB-6 Page 1	615	
33		G1R	MPB-6 Page 1	62	
34		DS3	MPB-6 Page 1	433	
35		FX1	MPB-6 Page 1	78,443	
36		FX2	MPB-6 Page 1	32,835	
37		FX4	MPB-6 Page 1	222	
38		FX5	MPB-6 Page 1	328	
39		FX6	MPB-6 Page 1	176	
40		FX7	MPB-6 Page 1	107	
41		FX8	MPB-6 Page 1	22,709	
42		SC2	MPB-6 Page 1	7,999	
43		SC3	MPB-6 Page 1	24,247	
44	Total				173,314,731
45		Proposed Forfeited Discounts (Account 487)	Line 26 x Line 45		457,733
46		**Proposed Adjustment to Account 487 Revenue**	**Line 46 - Line 2**		**265,020**

CUSTOMER-DEMAND
HISTORIC PERIOD - ORIGINAL FILING

COLUMBIA GAS OF KENTUCKY, INC.
CUSTOMER BASED COSTS - CUSTOMER CHARGE
FOR THE TWELVE MONTHS ENDED 12/31/2008

Attachment MPB-7

WITNESS: M. Balmert

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	GS-RES. (E) $	GS-OTHER (F) $	IUS (G)	DS-ML/SC (H)	DS/IS (I)	NOT USED (J)	NOT USED (K)	NOT USED (L)	NOT USED (M)
1		OPERATION & MAINT EXPENSE		13,102,214	10,420,394	2,494,463	1,387	3,566	179,738	0	0	0	
2	376	MAINS [1]	3	1,748,685	1,244,172	380,024	612	0	123,877	0	0	0	
3	380	SERVICES [2]	15	3,341,982	2,998,527	333,997	34	0	9,424	0	0	0	
4	381	METERS	16	407,468	249,737	150,498	94	436	6,703	0	0	0	
5	382	METER INSTALLATIONS	16	261,327	160,167	96,521	60	280	4,299	0	0	0	
6	383	HOUSE REGULATORS	16	116,659	71,500	43,088	27	125	1,919	0	0	0	
7	384	HOUSE REG INSTALLATIONS	16	38,499	23,596	14,220	9	41	633	0	0	0	
8	385	IND M&R EQUIPMENT	17	112,937	0	60,848	922	3,687	47,480	0	0	0	
9		TOTAL DEPRECIATION EXPENSE		6,027,557	4,747,699	1,079,196	1,758	4,569	194,335	0	0	0	
10		PROPERTY TAX [3]		14,374	10,316	3,721	3	9	362	0	0	0	
11		INCOME TAXES		3,734,002	2,751,512	794,288	1,384	2,725	184,092	0	0	0	
12		RETURN		9,250,808	6,816,737	1,967,810	3,429	6,751	456,080	0	0	0	
13		REVENUE TAXES											
14		(LINES 1,9,10,11,12 X 0.00160300)		51,503	0	0	0	0	0	0	0	0	
15		TOTAL ANNUAL CUST. BASED COST		32,180,458	24,746,658	6,339,478	7,961	17,620	1,014,607	0	0	0	
16		MONTHLY CUST. BASED COST											
17		(LINE 15 / 12 MONTHS)		2,681,705	2,062,222	528,290	663	1,468	84,551	0	0	0	
18		AVERAGE ANNUAL CUSTOMERS		139,227	124,717	14,424	2	6	78	0	0	0	
19		MONTHLY CUSTOMER BASED COST		19.26	16.54	36.63	331.50	244.67	1,083.99	0.00	0.00	0.00	0.0

NOTE: [1] CUSTOMER RELATED PORTION OF MAINS, [2] CUSTOMER RELATED PORTION OF SERVICES, [3] TAX ON ACCTS. 376, 380, 381, 382, 383, 384, & 385
[4] COSTS ARE INCLUDED IN THE IS CUSTOMER CHARGE.

COLUMBIA GAS OF KENTUCKY, INC.
CUSTOMER BASED COSTS - O & M
FOR THE TWELVE MONTHS ENDED 12/31/2008

CUSTOMER-DEMAND
HISTORIC PERIOD - ORIGINAL FILING

WITNESS: M. Balmert

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	GS-RES. (E) $	GS-OTHER (F) $	IUS (G) $	DS-ML/SC (H) $	DS/IS (I) $	NOT USED (J) $	NOT USED (K) $	NOT USED (L) $	NOT USED (M) $
1	874	MAINS & SERVICES [1]	14	1,286,922	1,003,877	223,911	283	0	58,851	0	0	0	
2	887	MAINS [1]	18	917,832	653,028	199,463	321	0	65,019	0	0	0	
3	892	SERVICES [2]	15	488,573	438,361	48,828	5	0	1,377	0	0	0	
4	878	METERS & HOUSE REGULATORS	16	1,753,290	1,074,592	647,578	404	1,876	28,841	0	0	0	
5	893	METERS & HOUSE REGULATORS	16	99,631	61,063	36,799	23	106	1,639	0	0	0	
6	876	M & R - INDUSTRIAL	8	37,889	0	37,889	0	0	0	0	0	0	
7	890	M & R - INDUSTRIAL	8	105,973	0	105,973	0	0	0	0	0	0	
8	879	CUSTOMER INSTALLATION	16	1,214,677	744,475	448,641	279	1,299	19,982	0	0	0	
9		TOTAL DISTRIBUTION		5,904,787	3,975,396	1,749,082	1,315	3,281	175,709	0	0	0	
10	901	SUPERVISION	6	6,936	6,213	719	0	0	4	0	0	0	
11	902	METER READING	6	1,233,444	1,104,907	127,785	12	49	691	0	0	0	
12	903	CUSTOMER RECORDS & COLLECTIONS	6	2,726,843	2,442,679	282,501	27	109	1,527	0	0	0	
13	904	UNCOLLECTIBLE ACCOUNTS		2,419,788	2,167,622	250,690	24	97	1,355	0	0	0	
14	905	MISC.	6	1,908	1,709	198	0	0	1	0	0	0	
15	920	SALARIES	6	0	0	0	0	0	0	0	0	0	
16	921	OFFICE SUPPLIES AND EXPENSE	6	515	461	53	0	0	0	0	0	0	
17	931	RENTS	6	0	0	0	0	0	0	0	0	0	
18		TOTAL CUSTOMER ACCOUNTS		6,389,434	5,723,591	661,946	63	255	3,578	0	0	0	

NOTE: [1] CUSTOMER RELATED PORTION OF MAINS, [2] CUSTOMER RELATED PORTION OF SERVICES

COLUMBIA GAS OF KENTUCKY, INC.

CUSTOMER BASED COSTS - O & M

FOR THE TWELVE MONTHS ENDED 12/31/2008

CUSTOMER-DEMAND

HISTORIC PERIOD - ORIGINAL FILING

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	GS-RES. (E) $	GS-OTHER (F) $	IUS (G)	DS-ML/SC (H)	DS/IS (I)	NOT USED (J)	NOT USED (K)	NOT USED (L)	NOT USED (M)
1	907	SUPERVISION	6	29,148	26,111	3,020	0	1	16	0	0	0	
2	908	CUSTOMER ASSISTANCE	6	150,492	134,809	15,591	1	6	85	0	0	0	
3	909	INFO. & INSTRUCTIONAL	6	56,350	50,478	5,838	1	2	32	0	0	0	
4	910	MISCELLANEOUS	6	506,174	453,426	52,440	5	20	283	0	0	0	
5	920	SALARIES	6	11,818	10,587	1,225	1	0	6	0	0	0	
6	921	OFFICE SUPPLIES AND EXPENSE	6	7,042	6,308	730	0	0	4	0	0	0	
7	931	RENTS	6	0	0	0	0	0	0	0	0	0	
8		TOTAL CUSTOMER SERV & INFO		761,024	681,719	78,844	8	29	426	0	0	0	
9	911	SUPERVISION	6	2,664	0	0	1	0	0	0	0	0	
10	912	DEMONSTRATION & SELLING	6	38,970	34,909	4,038	0	1	22	0	0	0	
11	913	ADVERTISING	6	5,336	4,780	553	0	0	3	0	0	0	
12	916	MISC.	6	(1)	(1)	0	0	0	0	0	0	0	
13		TOTAL CUSTOMER SERV & INFO		46,969	39,688	4,591	1	1	25	0	0	0	
14		TOTAL CUST. BASED COSTS - O&M		13,102,214	10,420,394	2,494,463	1,387	3,566	179,738	0	0	0	

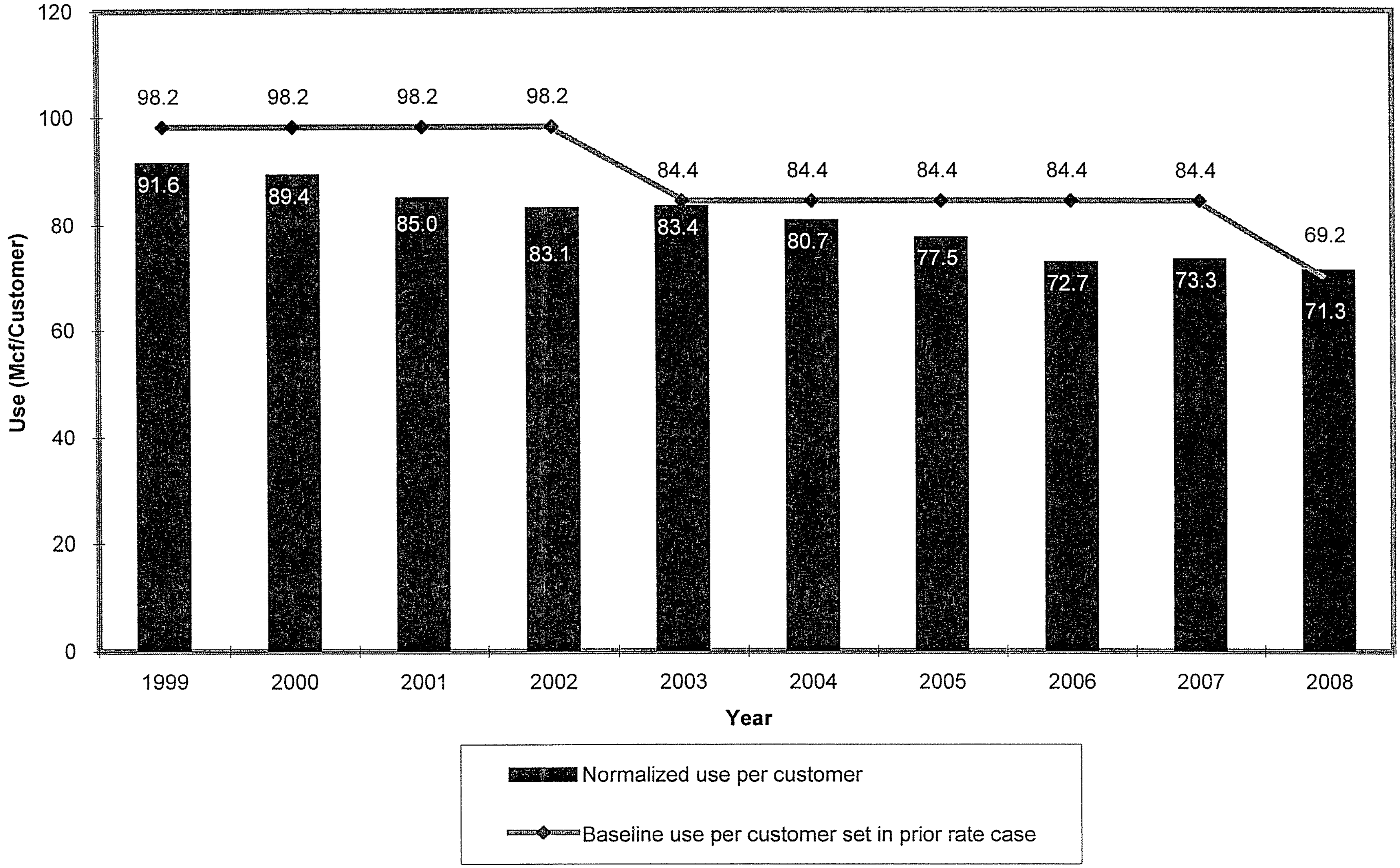
COLUMBIA GAS OF KENTUCKY, INC.
CUSTOMER BASED COSTS - GAS PLANT
FOR THE TWELVE MONTHS ENDED 12/31/2008

CUSTOMER-DEMAND
HISTORIC PERIOD - ORIGINAL FILING

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	GS-RES. (E) $	GS-OTHER (F) $	IUS (G)	DS-ML/SC (H)	DS/IS (I)	NOT USED (J)	NOT USED (K)	NOT USED (L)	NOT USED (M)
1	376	MAINS [1]	3	84,258,503	59,949,082	18,311,058	29,490	0	5,968,872	0	0	0	
2	380	SERVICES [2]	15	79,889,248	71,679,029	7,984,131	800	0	225,288	0	0	0	
3	381	METERS	16	11,783,395	7,222,043	4,352,197	2,710	12,609	193,837	0	0	0	
4	382	METER INSTALLATIONS	16	7,842,801	4,806,853	2,896,739	1,804	8,392	129,014	0	0	0	
5	383	HOUSE REGULATORS	16	3,792,593	2,324,481	1,400,795	872	4,058	62,388	0	0	0	
6	384	HOUSE REG INSTALLATIONS	16	2,327,988	1,426,824	859,842	535	2,491	38,295	0	0	0	
7	385	IND M&R EQUIPMENT	17	2,717,302	0	1,464,028	22,173	88,719	1,142,381	0	0	0	
8		TOTAL DISTRIBUTION PLANT		192,611,830	147,408,312	37,268,790	58,384	116,269	7,760,075	0	0	0	
	LESS:												
9	376	MAINS	3	28,110,346	20,000,230	6,108,941	9,838	0	1,991,337	0	0	0	
10	380	SERVICES	15	50,692,746	45,483,053	5,066,233	507	0	142,954	0	0	0	
11	381	METERS	16	4,064,067	2,490,867	1,501,063	935	4,349	66,854	0	0	0	
12	382	METER INSTALLATIONS	16	3,356,529	2,057,217	1,239,734	772	3,591	55,215	0	0	0	
13	383	HOUSE REGULATORS	16	1,027,633	629,836	379,556	236	1,100	16,905	0	0	0	
14	384	HOUSE REG INSTALLATIONS	16	1,640,703	1,005,587	605,994	377	1,756	26,990	0	0	0	
15	385	IND M&R EQUIPMENT	17	933,051	0	502,709	7,614	30,464	392,264	0	0	0	
16		TOTAL DIST. PLANT RESERVE		89,825,075	71,666,790	15,404,230	20,279	41,260	2,692,519	0	0	0	
17		NET CUST. BASED RATE BASE		102,786,755	75,741,522	21,864,560	38,105	75,009	5,067,556	0	0	0	
18		EQUITY CAPITAL @ 55.07%		56,608,778	41,713,886	12,041,688	20,986	41,310	2,790,906	0	0	0	
19		RETURN ON RATE BASE @ 9.00%		9,250,808	6,816,737	1,967,810	3,429	6,751	456,080	0	0	0	
20		RETURN ON EQUITY @ 12.25%		6,934,575	5,109,951	1,475,107	2,571	5,060	341,886	0	0	0	
21		INCOME TAXES											
22		(LINE 20 x 1.53846154) x 35%		3,734,002	2,751,512	794,288	1,384	2,725	184,092	0	0	0	

NOTE: [1] CUSTOMER RELATED PORTION OF MAINS, [2] CUSTOMER RELATED PORTION OF SERVICES

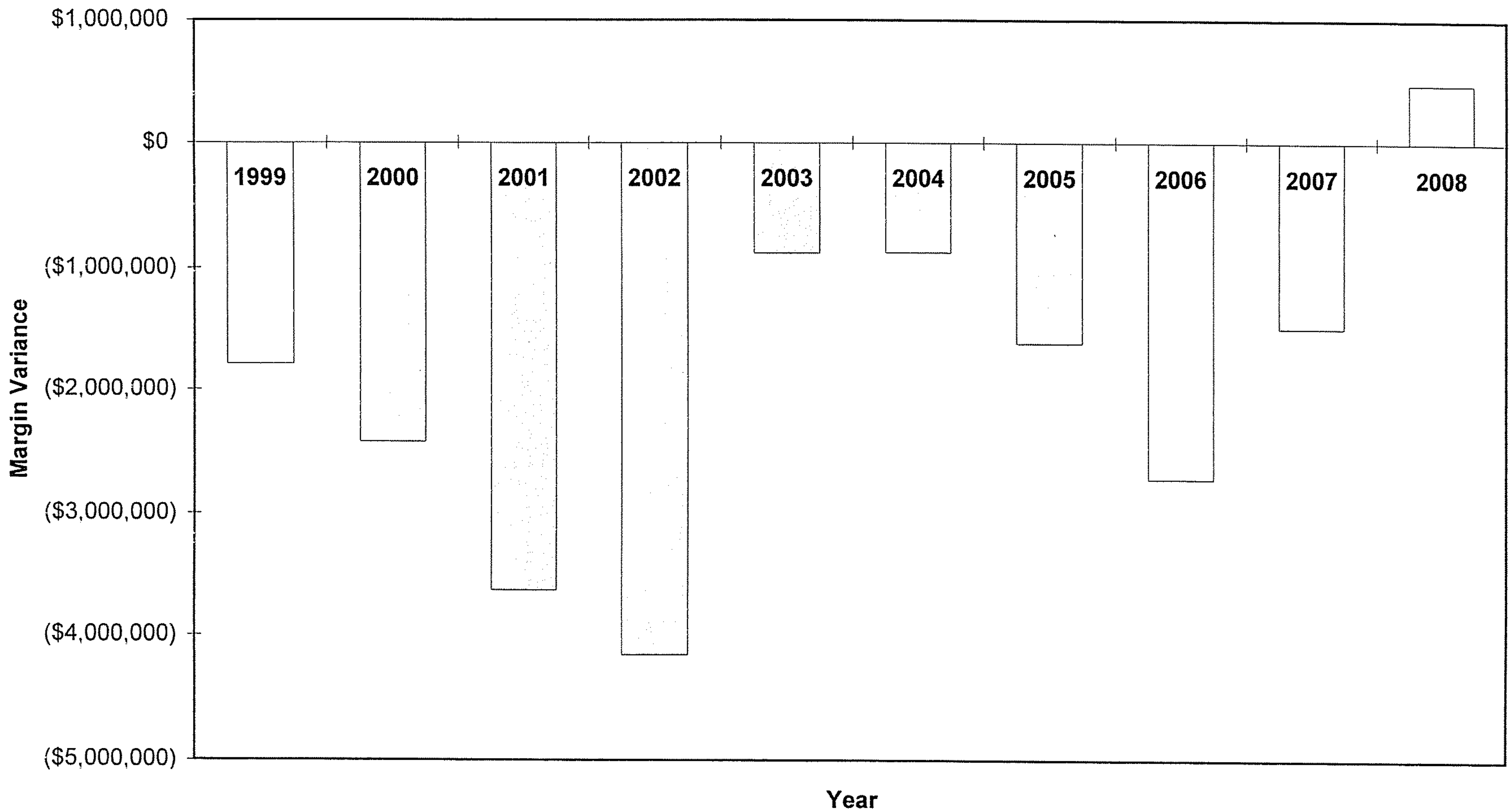
Average Annual Use per Customer
GSR/GTR Rate Schedules



COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141

WITNESS: M. BALMERT

Margin Impact from Current Volumetric-Based Rate Design
GSR/GTR Rate Schedules



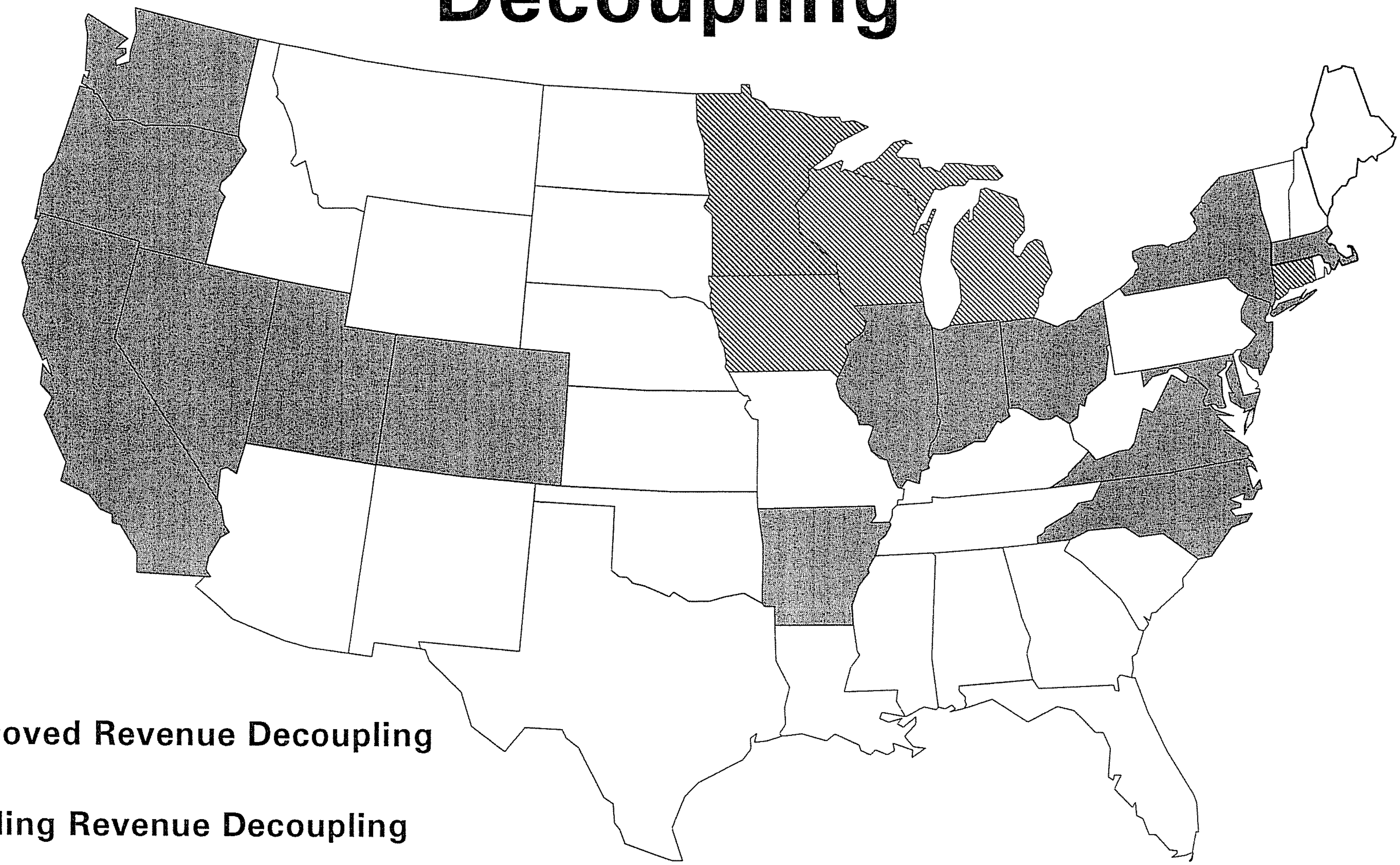
Columbia Gas of Kentucky, Inc.
Margin Impact from GSR/GTR Volumetric - Based Rate Design
For the Years 1999 - 2008

	1999	2000	2001	2002	Jan - Feb 2003	Mar - Dec 2003	2004	2005	2006	Jan - Aug 2007	Sep - Dec 2007	2008
Customers	124,508	126,253	126,243	126,186	126,564	126,564	126,034	125,325	124,109	124,022	124,022	122,986
UPC Baseline	98.2	98.2	98.2	98.2	98.2	84.4	84.4	84.4	84.4	84.4	69.2	69.2
UPC Normalized	91.6	89.4	85.0	83.1	83.4	83.4	80.7	77.5	72.7	73.6	71.5	71.3
Gain / (Loss) UPC	(6.6)	(8.8)	(13.2)	(15.1)	(14.8)	(1.0)	(3.7)	(6.9)	(11.7)	(10.8)	2.3	2.1
Rate / Mcf	2.1800	2.1800	2.1800	2.1800	2.1800	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715
Gain / (Loss)	(1,791,421)	(2,422,038)	(3,632,769)	(4,153,791)	(680,577)	(197,387)	(872,729)	(1,618,366)	(2,717,559)	(1,671,172)	177,949	483,353

Gain / (Loss) Summary By Year

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Gain / (Loss)	(1,791,421)	(2,422,038)	(3,632,769)	(4,153,791)	(877,964)	(872,729)	(1,618,366)	(2,717,559)	(1,493,223)	483,353	(19,096,507)

Natural Gas Revenue Decoupling



Approved Revenue Decoupling

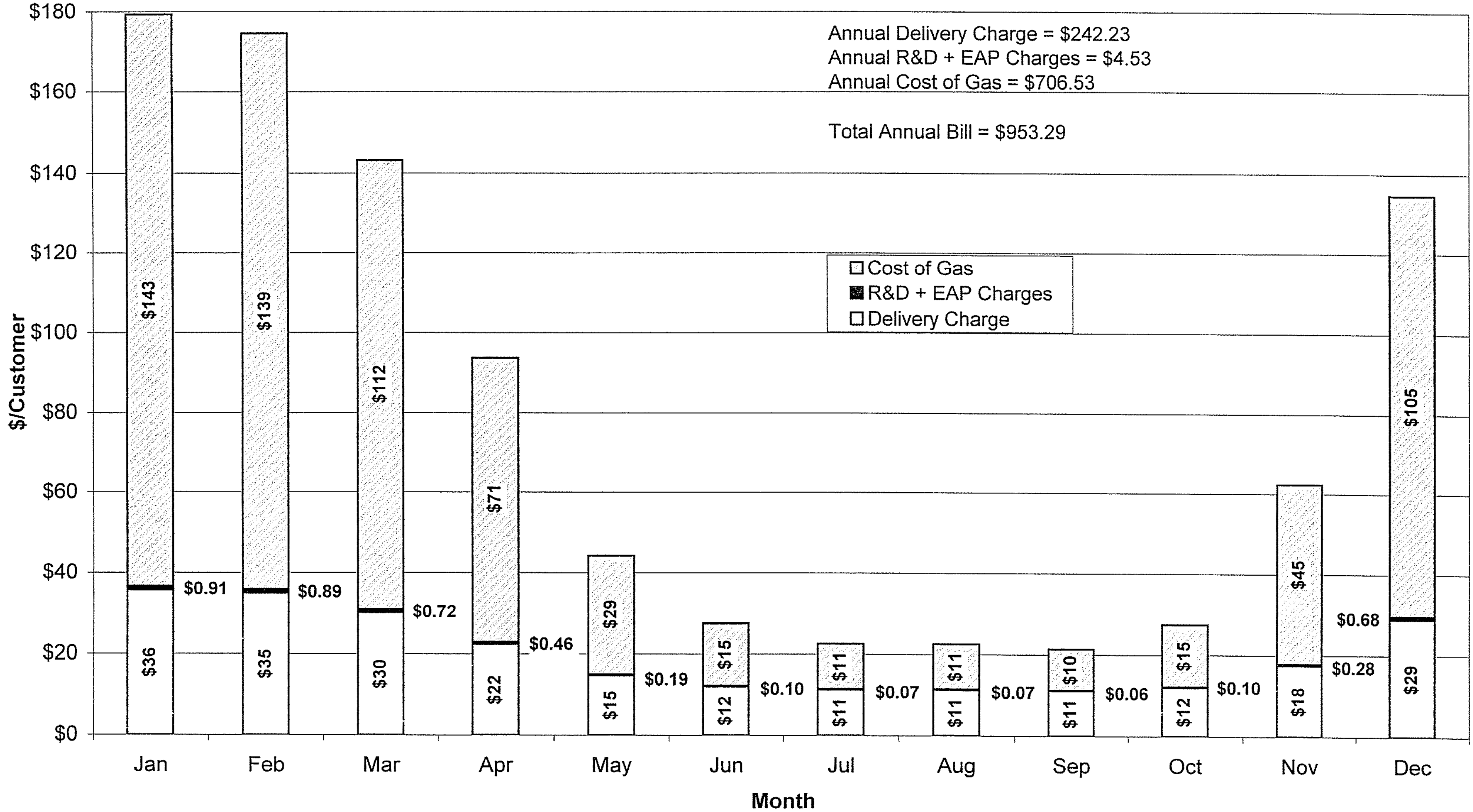
Pending Revenue Decoupling

Source: American Gas Association February 2009

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141

Average GSR Total Bills by Month

For the Twelve Months Ending December 31, 2008

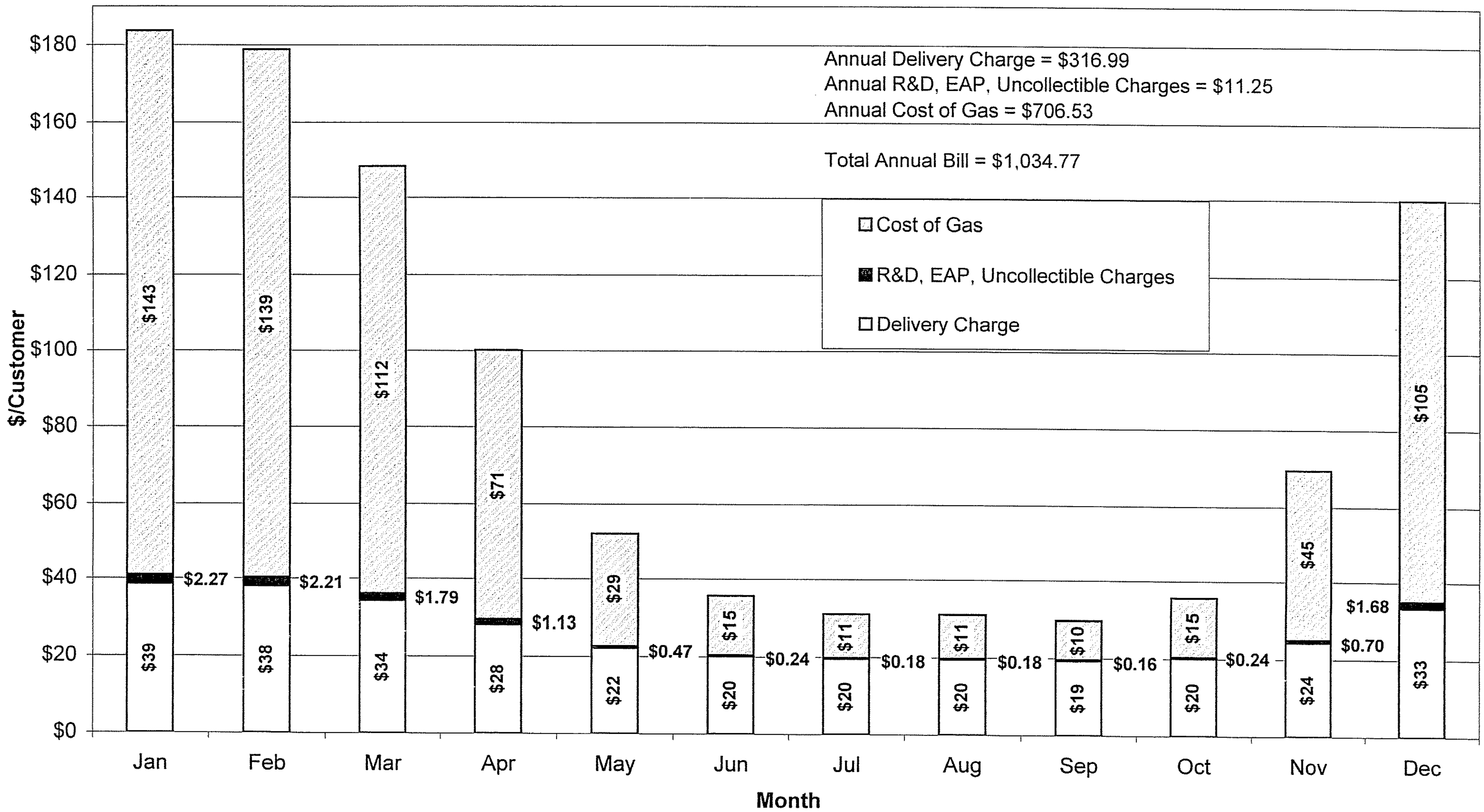


Columbia Gas of Kentucky, Inc.
Average GSR Total Bill by Month @ Present Rates
For the Twelve Months Ending December 31, 2008

Month (1)	GSR Customers (2)	GSR Normalized Mcf (3)	Usage Per Customer Mcf/Cus (4=3/2)	Customer Charge Revenue (5) ($)	Volumetric Delivery Charge Revenue @ $1.8715/Mcf (6) ($)	Total Delivery Charge Revenue (7=5+6) ($)	Volumetric EAP Charge Revenue @ $0.0525/Mcf (8) ($)	Volumetric R&D Charge Revenue @ $0.0124/Mcf (9) ($)	Volumetric GCA Charge Revenue @ $10.1224/Mcf (10) ($)	Total Bill (11=7+8+9+10) ($)
Jan	100,900	1,420,401.5	14.1	9.30	26.39	35.69	0.74	0.17	142.73	179.33
Feb	100,102	1,376,211.2	13.7	9.30	25.64	34.94	0.72	0.17	138.68	174.51
Mar	99,785	1,108,110.3	11.1	9.30	20.77	30.07	0.58	0.14	112.36	143.15
Apr	98,695	695,317.5	7.0	9.30	13.10	22.40	0.37	0.09	70.86	93.72
May	97,680	279,841.5	2.9	9.30	5.43	14.73	0.15	0.04	29.35	44.27
Jun	96,381	146,474.6	1.5	9.30	2.81	12.11	0.08	0.02	15.18	27.39
Jul	95,780	106,030.7	1.1	9.30	2.06	11.36	0.06	0.01	11.13	22.56
Aug	95,105	100,292.5	1.1	9.30	2.06	11.36	0.06	0.01	11.13	22.56
Sep	94,848	98,189.4	1.0	9.30	1.87	11.17	0.05	0.01	10.12	21.35
Oct	95,085	147,160.9	1.5	9.30	2.81	12.11	0.08	0.02	15.18	27.39
Nov	95,924	420,511.4	4.4	9.30	8.23	17.53	0.23	0.05	44.54	62.35
Dec	93,436	968,444.9	10.4	9.30	19.46	28.76	0.55	0.13	105.27	134.71
Total	1,163,721	6,866,986.4	69.8	111.60	130.63	242.23	3.67	0.86	706.53	953.29

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141

Average GSR Total Bills by Month
First Year Proposed Rates

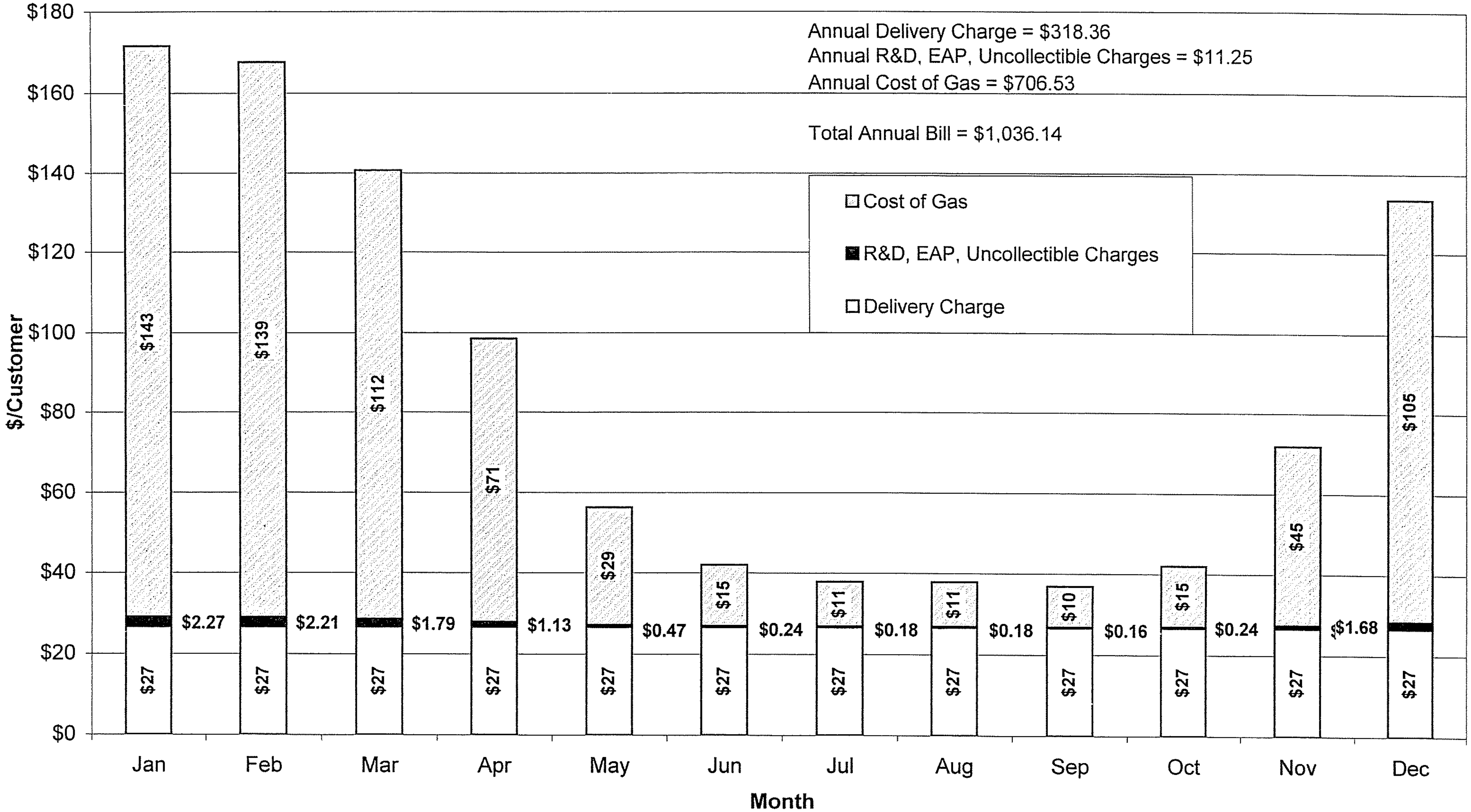


Columbia Gas of Kentucky, Inc.
Average GSR Total Bill by Month @ 1st Year Proposed Rates
For the Years 1999 - 2008

Month (1)	GSR Customers (2)	GSR Normalized Mcf (3)	Usage Per Customer Mcf/Cus (4=3/2)	Customer Charge Revenue (5) ($)	Volumetric Delivery Charge Revenue @ $1.4604/Mcf (6) ($)	Total Delivery Charge Revenue (7=5+6) ($)	Volumetric EAP Charge Revenue @ $0.0525/Mcf (8) ($)	Volumetric R&D Charge Revenue @ $0.0124/Mcf (9) ($)	Volumetric GCA Charge Revenue @ $10.1224/Mcf (10) ($)	Volumetric Uncollectible Charge Revenue @ $0.0964/Mcf (11) ($)	Total Bill (12=7+8+9+10+11) ($)
Jan	100,900	1,420,401.5	14.1	17.92	20.59	38.51	0.74	0.17	142.73	1.36	183.51
Feb	100,102	1,376,211.2	13.7	17.92	20.01	37.93	0.72	0.17	138.68	1.32	178.82
Mar	99,785	1,108,110.3	11.1	17.92	16.21	34.13	0.58	0.14	112.36	1.07	148.28
Apr	98,695	695,317.5	7.0	17.92	10.22	28.14	0.37	0.09	70.86	0.67	100.13
May	97,680	279,841.5	2.9	17.92	4.24	22.16	0.15	0.04	29.35	0.28	51.98
Jun	96,381	146,474.6	1.5	17.92	2.19	20.11	0.08	0.02	15.18	0.14	35.53
Jul	95,780	106,030.7	1.1	17.92	1.61	19.53	0.06	0.01	11.13	0.11	30.84
Aug	95,105	100,292.5	1.1	17.92	1.61	19.53	0.06	0.01	11.13	0.11	30.84
Sep	94,848	98,189.4	1.0	17.92	1.46	19.38	0.05	0.01	10.12	0.10	29.66
Oct	95,085	147,160.9	1.5	17.92	2.19	20.11	0.08	0.02	15.18	0.14	35.53
Nov	95,924	420,511.4	4.4	17.92	6.43	24.35	0.23	0.05	44.54	0.42	69.59
Dec	93,436	968,444.9	10.4	17.92	15.19	33.11	0.55	0.13	105.27	1.00	140.06
Total	1,163,721	6,866,986.4	69.8	215.04	101.95	316.99	3.67	0.86	706.53	6.72	1,034.77

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141

Average GSR Total Bills by Month
Second Year Proposed Rates



Columbia Gas of Kentucky, Inc.
Average GSR Total Bill by Month @ 2nd Year Proposed Rates
For the Years 1999 - 2008

Month (1)	GSR Customers (2)	GSR Normalized Mcf (3)	Usage Per Customer Mcf/Cus (4=3/2)	Customer Charge Revenue (5) ($)	Volumetric Delivery Charge Revenue @ $0.0000/Mcf (6) ($)	Total Delivery Charge Revenue (7=5+6) ($)	Volumetric EAP Charge Revenue @ $0.0525/Mcf (8) ($)	Volumetric R&D Charge Revenue @ $0.0124/Mcf (9) ($)	Volumetric GCA Charge Revenue @ $10.1224/Mcf (10) ($)	Volumetric Uncollectible Charge Revenue @ $0.0964/Mcf (11) ($)	Total Bill (12=7+8+9+10+11) ($)
Jan	100,900	1,420,401.5	14.1	26.53	0.00	26.53	0.74	0.17	142.73	1.36	171.53
Feb	100,102	1,376,211.2	13.7	26.53	0.00	26.53	0.72	0.17	138.68	1.32	167.42
Mar	99,785	1,108,110.3	11.1	26.53	0.00	26.53	0.58	0.14	112.36	1.07	140.68
Apr	98,695	695,317.5	7.0	26.53	0.00	26.53	0.37	0.09	70.86	0.67	98.52
May	97,680	279,841.5	2.9	26.53	0.00	26.53	0.15	0.04	29.35	0.28	56.35
Jun	96,381	146,474.6	1.5	26.53	0.00	26.53	0.08	0.02	15.18	0.14	41.95
Jul	95,780	106,030.7	1.1	26.53	0.00	26.53	0.06	0.01	11.13	0.11	37.84
Aug	95,105	100,292.5	1.1	26.53	0.00	26.53	0.06	0.01	11.13	0.11	37.84
Sep	94,848	98,189.4	1.0	26.53	0.00	26.53	0.05	0.01	10.12	0.10	36.81
Oct	95,085	147,160.9	1.5	26.53	0.00	26.53	0.08	0.02	15.18	0.14	41.95
Nov	95,924	420,511.4	4.4	26.53	0.00	26.53	0.23	0.05	44.54	0.42	71.77
Dec	93,436	968,444.9	10.4	26.53	0.00	26.53	0.55	0.13	105.27	1.00	133.48
Total	1,163,721	6,866,986.4	69.8	318.36	0.00	318.36	3.67	0.86	706.53	6.72	1,036.14

Columbia Gas of Kentucky, Inc.
Case No. 2009-00141
Annual Billing Impacts of Low Income Customers for Rate Schedules GSR/GTR
For the 12 Months Ending December 31, 2008

Line		Average Residential Customer Excl. Low Income ($)	Average Residential Low Income Customer ($)	Difference ($)	Percent
1	**Current Rates 1/**				
2	Customer Charge	9.30	9.30		
3	12 Months	12	12		
4	Annualized Customer Charge Bill	111.60	111.60		
5	Average Annual Normalized Consumption - Mcf	71.2	76.7		
6	Base Rate ($/Mcf)	1.8715	1.8715		
7	Annualized base Rate Bill	133.25	143.54		
8	Total Annualized Normalized Bill (Line 4 + Line 7)	244.85	255.14	10.29	4.2%
9	**2nd Year Proposed Rates (SFV) 1/**				
10	Customer Delivery Charge	26.53	26.53		
11	12 Months	12	12		
12	Annualized Customer Charge Bill	318.36	318.36		
13	Average Annual Normalized Consumption - Mcf	71.2	76.7		
14	Base Rate ($/Mcf)	0.0000	0.0000		
15	Annualized base Rate Bill	0.00	0.00		
16	Total Annualized Normalized Bill (Line 12 + Line 15)	318.36	318.36	0.00	0.0%
17	Current Rates vs Proposed Rates	73.51	63.22	(10.29)	

1/ Base Delivery Charges only

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
AMY L. EFLAND
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF AMY L. EFLAND

Q: Please state your name and business address.

A: My name is Amy Efland and my business address is 200 Civic Center Drive, Columbus, OH 43215.

Q: What is your current position and what are your responsibilities?

A: I am a Senior Forecast Analyst for NiSource Corporate Services Company. I assist with the development of short-range and long-range forecasts of customers, energy consumption and peak demand for nine NiSource gas distribution companies, including Columbia Gas of Kentucky ("Columbia" or the "Company"), and one NiSource electric company. I also assist with other business related analyses and forecasts.

Q: What is your educational background?

A. I attended Earlham College where I earned a Bachelor of Arts Degree in Economics and Miami University where I earned a Master of Arts Degree in Economics.

Q: Please describe your employment history?

A: From 1997 to 2002, I worked as a forecast analyst for Cinergy assisting with the production of the gas and electric and long-term forecasts of customers, energy consumption and peak demand for the Cinergy (PSI, ULH&P and CG&E) territories. I was promoted to Lead Analyst in 2002, a position I held until I left Cinergy in 2005. From 2005 to 2006, I worked as a Senior Forecasting Analyst with Limited Brands/Victoria's Secret Direct. I provided analysis and recommendations surrounding circulation levels of catalogues and assisted with catalogue messaging relating to marketing offers. From 2006 to 2008, I worked as a Senior Marketing Analyst for JP

Morgan Chase where I was responsible for the development of test designs for consumer and business banking marketing programs used to evaluate campaigns. I joined NiSource in 2008 as a Senior Forecast Analyst.

Q. Have you previously testified before the Kentucky Public Service Commission or any other regulatory commissions?

A: No.

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

A: I will explain how residential and commercial sales volumes are normalized for weather. I will also comment on the decrease in the residential and commercial customer count and residential consumption per customer.

Q: How does the definition of normal weather enter into this filing?

A: This filing includes a test year with twelve months of actual volume stated on the basis of normal weather. The twelve months of actual volume are stated on the basis of normal weather using the base-load/temperature-sensitive load normalization process.

Q: Describe the base-load/temperature-sensitive load normalization process.

A: For each month for the residential and commercial classes, actual billing month sales per customer is separated into base-load and temperature-sensitive load. Temperature-sensitive load is then scaled by the ratio of normal to actual heating degree days ("HDD") to derive normal temperature-sensitive load per customer. The normal temperature-sensitive load per customer is then added to the base-load per customer to arrive at the normal load per customer. This value is then multiplied by the customer count to derive the normal sales volume for the customer base.

Q: What is HDD?

A: It is a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature. HDD are calculated by subtracting a day's average temperature from 65.

Q: What data sources did you use for your calculations?

A: I used company billing records to obtain monthly customer counts and billed volumes. The temperatures used to calculate HDD were obtained from National Weather Service Weather Stations. A weighted average HDD for the company is calculated using the percent of residential heating customers assigned to each station as a weight for that station. Normal weather is the (20-year) average of 1989-2008.

Q: How does the procedure calculate base load?

A: The procedure assumes no temperature sensitive (heat) load in July and August. For September, no temperature sensitive (heat) load is assumed when total load per customer per day (Total Load/Customer/Day) is less than July and/or August. The base load per customer per day is calculated by taking the average of the two lowest observed values from the months of July through September.

Q: How does the procedure weather normalize monthly volumes?

A: First, the monthly base load per customer is determined. This equals the lesser of the base load per customer per day multiplied by the days in the billing cycle ((base load/customer/day)*days in billing cycle) or the monthly total load per customer. Second, monthly heat load per customer is calculated. Heat load per customer equals the total load per customer minus the base load. Third, the heat load per customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD. Finally, normal load per customer is calculated by adding the base load per customer to the normal heat load per customer. A total monthly normalized volume is generated by multiplying monthly customers by the monthly normal load per customer.

Q: Has the normalization procedure changed from the last rate filing?

A: Yes, there are two updates. First, the definition of normal weather is defined in this filing as the average HDD for the 20 years ended 2008. The previous filing defined normal weather as the 20-year average ending in 2005. Second, the HDD reference point used in the normalization procedure has changed. In the previous filing, the HDD reference point was 63 degrees for the residential class and 64 degrees for the commercial class. Columbia now uses 65 degrees for both classes. This change was made to be consistent with the company billing system that uses HDD to calculate estimated bills and weather normalized volume. This has little impact on the normal annual volume. The normal volume at the new reference temperature of 65 is 0.3% higher for the residential class and 0.1% higher for the commercial class when using the test year customers and volumes.

Q: Describe Columbia's recent change in customer count.

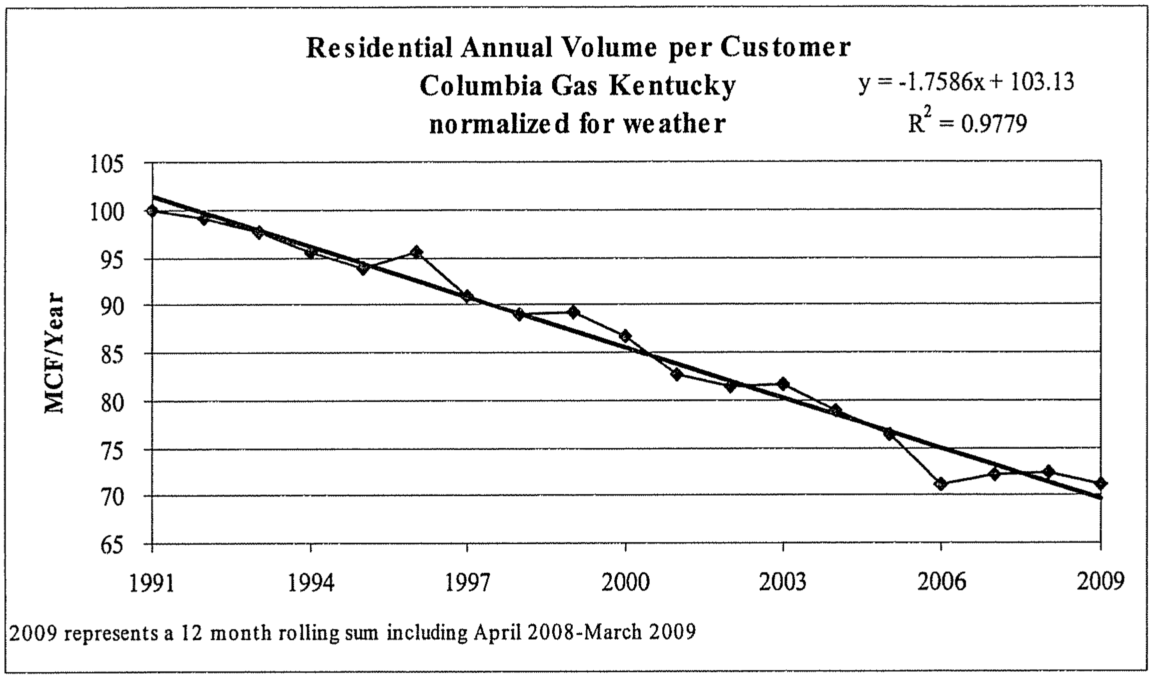
A: The table below illustrates that from the end of 2003 to the end of 2008, Columbia connected 3,294 new residential customers and 1,034 new commercial customers. Columbia also split some accounts into additional meters, which increases the customer count, but adds no volume. Despite these additions, both the residential and commercial customer counts have fallen. The residential customer count has dropped every year since 2003 with a total loss since 2003 of 4,208. Commercial customers have dropped every year except for 2004 with a total loss since 2003 of 317.

	Residential Customers	Change	New Sets	Meter Splits	Attrition
2003	127,932				
2004	127,072	(860)	993	20	(1,873)
2005	126,412	(660)	820	10	(1,490)
2006	125,429	(983)	716	7	(1,706)
2007	124,953	(476)	418	12	(906)
2008	123,724	(1,229)	347	13	(1,589)
2003-2008		(4,208)	3,294	62	**(7,564)**

	Commercial Customers	Change	New Sets	Meter Splits	Attrition
2003	14,676				
2004	14,748	72	317	15	(260)
2005	14,745	(3)	218	5	(226)
2006	14,539	(206)	188	15	(409)
2007	14,450	(89)	151	9	(249)
2008	14,359	(91)	160	10	(261)
2003-2008		(317)	1,034	54	**(1,405)**

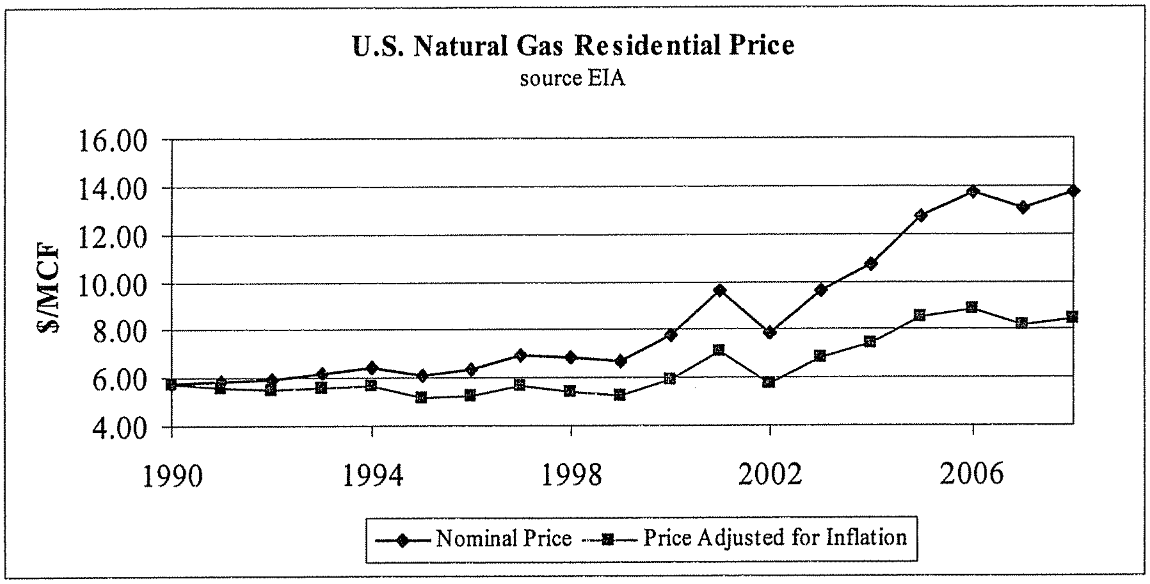
Q: Describe Columbia's recent trends related to residential use per customer.

A: The graph below illustrates the recent trends in Columbia's residential use per customer. Since 1999, weather normalized usage for residential heating customers has fallen 18.9% from 89.26 MCF per year to 72.38 MCF per year. Recent data, 2006 to 2008, shows an increase in use of 1.9%. January through March 2009 usage, representing over 50% of annual usage, indicates a downward trend, suggesting that the 2006-2008 increase is not an indication of a change in the overall use per customer trend. This is represented by the last data point on the chart below which is a twelve-month sum of usage including January through March 2009 data. This is consistent with a number of periods in the data that exhibit a small increase in use followed by a decrease. The data shows an increase in annual use of 0.2% from 1998-1999 and an increase of 0.3% from 2002-2003. Both of these periods were followed by three years of consecutive decreases, indicating that these points were not representative of the overall trend.



Q: What factors have caused the reduction in customer usage?

A: During most of the 1990s natural gas consumption per residential customer was decreasing by 1% to 2% per year. This happened in spite of a relatively constant nominal price illustrated in the graph below. When adjusted for inflation, the price was actually decreasing. This structural conservation was a result of increased appliance efficiency and more efficient construction standards that followed the major price increases that occurred in the 1970s and 1980s. Annual conservation increased significantly with the large price increases that occurred in the winters of 2000-2001, 2004-2005, 2005-2006. With limited end uses for natural gas, increasing appliance efficiency, and higher building standards, the downward trend in consumption per customer will continue. Appliance choice could also become a significant factor. If customers choose electric water heaters, cooking ranges and heat pumps, the potential floor will fall with appliance saturation as well as efficiency.



Q: Does this complete your Prepared Direct testimony?

A: Yes, however I reserve the right to file rebuttal testimony if necessary.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
PANPILAS W. FISCHER
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF PANPILAS W. FISCHER

Q: Please state your name and business address.

A: My name is Panpilas W. Fischer and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: What is your current position and responsibilities?

A: My current position is the Manager of Corporate Income Tax. As Tax Manager, my principal responsibilities include supervision and preparation of all of Columbia Gas of Kentucky's ("Columbia") income tax activities including the booking of income tax accruals and deferred tax entries, the filing of income tax returns, tax research and planning and the preparation of income tax data and related testimony for rate proceedings.

Q: What is your educational background?

A. I received a Bachelor of Business Administration in Accounting from The Ohio State University in 1987. I am a Certified Public Accountant and member of the Ohio Society of Certified Public Accountants.

Q: Please describe your employment history?

A: I began my career with KPMG as a Staff Auditor in 1987. I then joined the firm of Clark, Schaefer, Hackett and Co., CPA's as a Senior in 1989 where I performed financial audits, reviews and compilations, and prepared and reviewed tax returns. In October 2000, I started working as a tax analyst for NiSource Corporate Services Company and in October 2003 I assumed my current position.

Q: Have you previously testified before the Kentucky Public Service Commission or any other regulatory commissions?

A: I have previously provided written testimony to the Kentucky Public Service Commission, the Public Utilities Commission of Ohio and the Public Service Commission of Maryland.

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

A: My testimony will address the calculation of the proper level of federal and state income taxes included in the cost of service. This calculation includes the appropriate level of statutory tax adjustments for this proceeding, including depreciation, and the determination of deferred income taxes for rate purposes.

Q: What schedules are you responsible for in this proceeding?

A: I am responsible for Schedule Nos. E-1, E-2, and B-6. These schedules and the supporting work papers were prepared by me or under my direction, and the information set forth is true and correct, to the best of my knowledge and belief.

Q: What federal income tax rates have been utilized for the test period?

A: The Internal Revenue Code ("IRC") provides for a tax rate of 34% for corporations with taxable income up to $10 million. The rate increases to 35% for taxable income over $10 million. Beginning at $15 million of taxable income the rate is 38% until taxable income reaches $18.33 million. All taxable income over $18.33 million is taxed at the 35% rate.

The effect of the 38% rate is to phase out the 1% savings at the 34% rate for the first $10 million of taxable income. Effectively, the tax rate is 35% for corporations with taxable income over $18.33 million for all taxable income.

Q: What rate was utilized for Kentucky Income taxes?

A: The rates utilized are the statutory tax rates based on separate return taxable income and tax liability as follows:

4% of the first $50,000 of taxable income

5% of the next $50,000 of taxable income

6% of the taxable income in excess of $100,000

Q: Please explain the income tax calculation shown on Schedule No. E-1.

A: This schedule shows the computation of federal income taxes for the year ending December 31, 2008, including the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the customer cost of service for the calculation of income tax expense. The tax calculation begins with net operating income before income taxes (Line1). This amount is adjusted by interest, reconciling items detailed on page 2 of Schedule No. E-1 and state income tax. The items on page 2 reflect the difference between income and expenses as properly reflected on the regulated books of the company, and income and expenses as required/allowed for reporting taxable income based on the IRC. These adjustments are commonly referred to as "Schedule M" adjustments in reference to their reporting position on the federal income tax return (Form 1120). The tax return differences can be merely timing differences between book and tax return reporting or can be permanent differences in taxable income. Normally, the tax expense effects of permanent differences are recorded currently (flowed through) while timing differences are deferred (normalized) on the books until the timing differences are eliminated. Regulatory orders may, in certain instances, change the normal accounting for permanent and timing tax adjustments.

The next step in the calculation is to apply the appropriate federal tax rates to the taxable income for return purposes (Line 9) to arrive at current year federal income taxes payable (Line 10).

Line 11 represents federal income tax expense items recorded in 2008 related to prior year taxes. The direct adjustment related to the books to return reconciliation for the year 2007 total $47,333. The books to return adjustments represent the difference between what was recorded at December 31, 2007 for current tax expense and the actual taxes per the filed tax. This item has been pro forma adjusted to reflect a zero impact on 2008. Line 13 represents the Net current Federal Income Taxes.

Q: Please explain the income tax schedule shown on Schedule E-1.2.

A: The schedule reflects estimated timing and flow through differences between the regulatory books and what will be allowed on the tax return filed in 2008.

Q: Does the state income tax provision include a pass back of excess deferred income taxes as a result of reductions in the Kentucky state income tax rate?

A: Yes. Included in Line 19 is an adjustment for the annual amortization. This benefit will occur over the remaining book life of the property in service at the time Kentucky state income tax rates were lowered. (The total amount of Columbia's regulatory liability, including a tax gross up at the end of the test period, is $1,155,665. This includes any prior year flow through as an asset).

Q: Are there any federal excess or deficient taxes included in rates?

A: Yes. Columbia has a regulatory liability for federal excess, including gross up, of $886,224. The amortization is included in Line 16.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

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

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF JOHN J. SPANOS

Q: Please state your name and business address.

A: My name is John J. Spanos and 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, Inc. – Valuation and Rate Division.

Q. How long have you been associated with Gannett Fleming, 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 of the Valuation and Rate Division.

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 February 2008.

Q. Please outline your experience in the field of depreciation.

A. In June, 1986, I was employed by Gannett Fleming, 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, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), 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, CG&E, ULH&P, 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 the Valuation and Rate Division of Gannett Fleming, 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; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Duke Energy Carolinas; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee American Water Company; Columbia Gas of Maryland;

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, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any regulatory utility commissions on the subject of utility plant depreciation?

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; Maryland Public Service Commission; Washington Utilities and Transportation Commission; the Tennessee Regulatory Commission; the Regulatory Commission of Alaska; and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "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." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

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

A: I sponsor the depreciation study performed for Columbia Gas of Kentucky, Inc. ("Columbia" or "the Company").

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. Was your depreciation study included as part of the Application filed in this case?

A. Yes, it is included as a report entitled, "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2008." This report sets forth the results of my depreciation study for Columbia.

Q. Are you familiar with the contents of the depreciation study filed as part of the Application in this case?

A. Yes.

Q. Is the study a true and accurate copy of your depreciation study?

A. Yes.

Q. Was the depreciation study prepared under your direction and control?

A. Yes.

Q. Does the study accurately portray the results of your depreciation study as of December 31, 2008?

A. Yes.

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-6 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2008, the book reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page III-7 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-101 presents the results of the salvage analysis. The section beginning on page III-132 presents the depreciation calculations related to surviving original cost as of December 31, 2008.

Q. **Please explain how you performed your depreciation study.**

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

For General Plant Accounts 391.1, 391.11, 391.12, 394.0, 395.0 and 398.0, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2008. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining 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 composite remaining lives and 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's 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 2008. 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, 2008.

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'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 39-R1.5 indicates an average service life of thirty-nine years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. Have you physically observed Columbia's plant and equipment in the field as part of your depreciation assignments?

A. Yes. I made field reviews of Columbia's property on March 18 and 19, 2002 and October 28, 2008, to observe representative portions of plant and it was determined an additional trip for this study was not necessary. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1969 through 2008 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 composite remaining lives and 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 remaining life method, and using remaining lives weighted consistent with the equal life group procedure.

Q. Please describe the straight line remaining life method of depreciation.

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

Q. Please describe the equal life group procedure.

A. The equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals. This procedure is the most accurate for matching recovery of the asset to consumption or utilization of the asset.

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 391.1, 391.11, 391.12, 394.0, 395.0 and 398.0 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 51% 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 2008 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1938-2008 and 1974-2008 experience bands are presented on pages III-35 through III-40 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-35 shows $81,088 retired at age 0.5 with $132,572,129 exposed to retirement. Consequently, the retirement ratio is .0006 and the surviving ratio is 0.9994. These life tables, or original survivor curve, are plotted along with the estimated smooth survivor curve, the 68-R1.5 on page III-34.

My calculation of the annual depreciation related to the original cost at December 31, 2008, of utility plant is presented on pages III-143 through III-148. The calculation is based on the 68-R1.5 survivor curve, 15% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page III-4.

Q. Was there separate life and net salvage analysis performed for the subaccounts of Account 376, Mains?

A. No, there was not. The historical data did not maintain a type pipe identifier, but historical balances were available by type pipe, therefore, separate life characteristics could not be accurately studied. Thus, one common service life and net salvage estimate for all mains. The common survivor curve and net salvage percent was applied to the surviving balance as of December 31, 2008 by subaccount.

Q. Explain what was different at the subaccount level.

A. A main replacement program has been established for bare steel and cast iron mains. The program is a 30 year program, starting at the beginning of 2008, and at the end of the 30 years all bare steel and cast iron pipe will have been replaced. Therefore, the depreciation rates must be established to match capital recovery to life expectancy. In order to accomplish the appropriate matching principle, the surviving bare steel and cast iron investment must be recovered by year-end 2037. Consequently, the annual depreciation rate for bare steel and cast iron in Account 376 has a truncation date of December 2037.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF JUNE M. KONOLD ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF JUNE M. KONOLD

Q: Please state your name and business address.

A: My name is June M. Konold and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: What is your current position and responsibilities?

A: I am employed by NiSource Corporate Service Company ("NCSC") as a part-time Project Manager in the Accounting Department. In this position, I serve all of the NiSource Energy Distribution East companies, including Columbia Gas of Kentucky, Inc. ("Columbia").

Q: What is your educational background?

A. In 1988, I graduated from The Ohio State University with a Bachelor of Science in Business Administration degree, double majoring in Accounting and Finance. I am a Certified Public Accountant and a member of the Ohio Society of Certified Public Accountants.

Q: Please describe your employment history?

A: I began my career with Columbia Gas of Ohio, Inc. in 1988 as an Associate Accountant. Between 1988 and 1999 I held various positions of increasing responsibility. In 1999, I was promoted to the Manager of Support Services and in 2000 I was promoted to the Director of Regulatory Accounting. Later that year, I was promoted to the Controller of the Exploration and Production Segment and the Merchant Energy Segment, a position newly formed as a result of Columbia Energy Group's merger with NiSource Inc. In August 2002, I resigned from that position to pursue my current position of part-time employment.

Q. Have you previously testified before the Kentucky Public Service Commission or any other regulatory commissions?

A: Yes, I have previously filed testimony with the Kentucky Public Service Commission, as well as with the Pennsylvania Public Utility Commission and the Maryland Public Utility Commission.

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

A: The purpose of my testimony is to request a reconciling mechanism that would recover the pension and other postretirement employee benefits ("OPEB") expenses described in the accounting application that was filed in Case No 2009-00168 on April 23, 2009.

Q: What are postretirement employee benefits other than pensions?

A: In general, OPEB are benefits other than retirement income (e.g. pension) benefits provided to retirees. For Columbia this includes employer-sponsored health care coverage and life insurance.

Q: How are pension and OPEB expenses calculated?

A: Pension and OPEB expenses are calculated pursuant to the provisions of Statement of Financial Accounting Standard ("SFAS") No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than

Pensions." Both SFAS 87 and SFAS 106 require that pension and postretirement benefits be accrued and charged to operations over the time period employees perform services. The net periodic benefit cost is calculated as follows:

Net Periodic Benefit Cost Formula

+	Service Cost
+	Interest Cost
-	Expected return on plan assets
+/-	Amortization of prior service cost
+/-	Amortization of net gains or losses
=	**Net periodic benefit cost**

Q: How does Columbia currently recover these costs?

A: Columbia currently recovers its pension and OPEB expenses through the base rate approval granted in Case No. 2007-00008. The level of pension and OPEB expense granted in that case was ($15,800) and $579,883, respectively.

Q: How does Columbia propose to recover its pension and OPEB expense in the future?

A: On April 23 2009, Columbia filed an application in Case No. 2009-00168 in which Columbia requested authority to defer the difference between annual Pension and OPEB expense calculated pursuant to SFAS 87 and SFAS No. 106 and annual Pension and OPEB expense included in base rates. The application requested that Pension and OPEB expense attributable to operation and maintenance expense be deferred and recognized as a regulatory asset or regulatory liability pursuant to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As of May 1, 2009 – the date this testimony was filed – the Commission had not yet acted upon that application. Therefore, I am renewing Columbia's request for the accounting authority described above.

In addition, Columbia proposes to establish an annual reconciling mechanism ("Pension and OPEB Mechanism" or "Rider POM") to recover the deferred pension and OPEB expenses, assuming that the Commission authorizes the requested accounting authority.

Q: Please describe how Columbia's proposed Rider POM will work?

A: Rider POM is a tracking mechanism under which Columbia would make annual rate adjustments to collect or pass back deferred pension and OPEB expenses. After the end of each fiscal year ending June 30th, Columbia will file a proposed tariff revision with the Commission to adjust Rider POM to collect from or return to customers over a twelve month period those amounts recorded as a regulatory asset or liability.

Q: When would Rider POM be filed?

A: Tariff Sheets reflecting Rider POM would be filed annually on July 30th of each year, beginning July 30, 2010. Pending Commission approval, revised Rider POM rates would be effective with meter readings on and after Unit 1 of Columbia's September billing cycle each year.

Q: Would Rider POM be included in rates as a fixed cost?

A: Yes. Columbia proposes that the rate derived from Rider POM, set forth on Tariff Sheet 59, would be calculated as a fixed charge and reflected on customer bills in the Customer Charge or Customer Delivery Charge.

Q: Why is Columbia proposing Rider POM?

A: As indicated in the application filed by Columbia in Case No. 2009-00168, Pension and OPEB costs are volatile due to the return on plan assets and discounts rates – factors that are beyond the control of Columbia. The volatility of these expenses creates a situation where it is almost impossible for Columbia or the Commission to determine a representative level of Pension and OPEB expense for inclusion in base rates. Rider POM allows the Commission and Columbia the ability to set rates on an annual basis to recover Pension and OPEB expense in a timely manner without having to incur the significant expense of filing a base rate proceeding.

Q: Please describe the volatility of Pension and OPEB costs.

A: Columbia's Pension and OPEB expense has varied significantly during the last six years as illustrated through the following table[1], which sets forth Columbia's Pension and OPEB expense for the calendar years 2004 through 2009.

Year	Pension Expense	Change From Prior Year	Percent of Change	OPEB Expense	Change From Prior Year	Percent of Change
2004	$ 289,648			$ 630,804		
2005	$ 212,790	$ (76,858)	26.5%	$ 658,342	$ 27,538	4.4%
2006	$ (104,133)	$ (316,923)	148.9%	$ 710,863	$ 52,521	8.0%
2007	$ (4,727)	$ 99,406	95.5%	$ 542,312	$ (168,551)	23.7%
2008	$ (152,146)	$ (147,419)	3118.7%	$ 529,273	$ (13,039)	2.4%
2009 (Est)	$ 980,525	$ 1,132,671	744.5%	$ 791,661	$ 262,388	49.6%

Q: Why are Pension and OPEB expenses so volatile?

[1] Table reflects pension and OPEB amounts attributable to operation and maintenance expense only.

A: Pension and OPEB costs are volatile due to the return on plan assets and discount rates – factors that are beyond the control of Columbia. The market value of Columbia's Pension and OPEB plan assets are subject to significant changes caused by fluctuations in long-term interest rates and in trust asset returns available in the capital markets. During 2008, the S&P 500 Index declined nearly 38.5%, while at the same time, corporate bond prices also declined as a result of the current economic crisis. The MSCI EAFE Index, a common benchmark for international equities, also declined over 43% during 2008. Similarly, NiSource pension plan assets and OPEB assets declined as a result of negative returns amounting to 30.3% and 31.8% respectively.

The following table illustrates the change in the value of NiSource's Master Retirement Trust and Columbia Energy Group's Qualified Pension assets from December 31, 2007 to December 31, 2008.

Change in Market Value of Qualified Pension Plan Assets

	NiSource Master Retirement Trust	Columbia Energy Group Pension Plan
Asset Values at 12/31/07	$ 2,238,200,000	$ 881,300,000
2008 Benefit Payments	(161,800,000)	(65,600,000)
2008 Sponsor Contributions	1,700,000	0
2008 Investment Loss	(635,700,000)	(250,300,000)
2008 Divestiture	(1,900,000)	0
Asset Value at 12/31/08	$ 1,440,500,000	$ 565,400,000

Q: How did the change in asset value impact the change in expense for 2009?

A: The impact of the change in asset value is shown in the following table which provides for reconciliation of Qualified 2008 FAS 87 Expense with Qualified 2009 FAS 87 Expense. The table demonstrates that the change in asset value is the primary reason driving the change in expense.

	NiSource Master Retirement Trust	Columbia Energy Group Pension Plan
Total Qualified 2008 FAS 87 Expense	$ (24,100,000)	$ (11,300,000)
2008 Asset Experience	140,800,000	50,400,000
Change in Expected Return (9% to 8.75%)	3,600,000	1,400,000
Plan Changes	0	0
Other Assumption Changes & Experience	1,200,000	4,200,000
Total Qualified 2009 FAS 87 Expense	$ 121,500,000	$ 44,700,000

Q: How does the return experienced by NiSource compare with other major asset classes?

A: The return experienced by NiSource's Master Retirement Trust during the calendar year 2008 was consistent with that experienced by most major asset classes as demonstrated by the following table that compares 2008 returns experienced by major asset classes with average annual investment returns for those asset classes during the 20 years ending December 31, 2007.

Asset Class	Index	2008 Performance	20-Year Annual Performance Thru 2007
NiSource Master Retirement Trust		-30.3%	10.5%
US Equity	S&P 500	-38.5%	11.8%
Small Cap US Equity	Russell 2000	-33.8%	11.3%
International Equity	MSCI-EAFE	-43.4%	7.5%
Emerging Markets Equity	MSCI-Emerging Mkts.	-53.2%	16.3%
US Bonds	BC US Aggregate	5.2%	7.6%
US Treasury Bonds	BC US Treasury	13.7%	7.4%
High Yield Bonds	ML High Yield Bond	-26.2%	8.9%
Cash	T-Bills (90 Day)	1.8%	4.7%

Q: What were the returns experienced by NiSource's Master Retirement Trust during the last ten years?

A: The returns experienced by NiSource's Master Retirement Trust during the last ten years have varied significantly with market conditions as demonstrated by the following table which sets forth historical returns for the most recent ten years net of fees.

Year	Annual Return
2008	-30.3%
2007	10.5%
2006	13.8%
2005	7.6%
2004	11.7%
2003	28.2%
2002	-9.1%
2001	0.5%
2000	2.8%
1999	16.3%

Q: How does the volatility in Pension and OPEB expense impact earnings and/or rates charged to customers.

A: As previously stated, this volatility creates a situation where it is almost impossible for Columbia or the Commission to determine a representative level of Pension and OPEB expense for inclusion in base rates. This inability of Columbia or the Commission to include a representative level can result in a significant impact on earnings and/or rates charged to customers. Columbia's Pension and OPEB expense during the calendar year 2009 is approximately $1,208,103 over that which is reflected in Columbia's current base rates. For this reason, Columbia is seeking a long-term solution to the problem that not only alleviates the difficulty of trying to determine a representative level of Pension and OPEB expense to include in base rates, but also ensures that Columbia's customers pay no more or no less than the prudently incurred costs associated with its Pension and OPEB obligations. In addition, Rider POM would provide the Commission and Columbia the ability to set rates on an annual basis to recover Pension and OPEB expense in a timely manner without having to incur the significant expense of filing a base rate proceeding.

Q: If the Commission does not approve the application that was filed in Case No 2009-00168 or Rider POM, what is Columbia's proposal for the treatment of pension and OPEB expenses?

A: If Columbia is not authorized to defer the pension and OPEB expenses and recover them through Rider POM, then the 2009 level of Pension and OPEB expense should be used for purposes of calculating base rates. This is the level of expense that Columbia is actually incurring today, and will incur for the remainder of 2009.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED DIRECT TESTIMONY OF
ERICH A. EVANS
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Daniel A. Creekmur, Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
dcreekmur@nisource.com

Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 1, 2009

PREPARED DIRECT TESTIMONY OF ERICH A. EVANS

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

A: My name is Erich Evans and my business address is 200 Civic Center Dr., Columbus, OH 43215.

Q. **By whom are you employed?**

A. I am employed by NiSource Corporate Services Company, as Director, Commodity & Performance. I am responsible for commodity sales programs as well as department metric reporting.

Q. **Please describe your professional experience and educational background.**

A. I have been employed in various capacities with NiSource since 2003 in positions of increasing responsibilities in the NiSource Corporate Services Company. I started with the company as Manger, Gas Transportation and Sales support. In 2004 I was promoted to Director, Gas Transportation and Sales Support; in 2006 I became the Director, Distribution Customer Programs; and in 2007 I became the Director, Commodity & Performance. Prior to working for NiSource I held various positions with CSC Energy Services and Enron Energy Services. I graduated from Miami University with a Bachelor of Arts degree, majoring in Economics. In addition, I have attended a variety of seminars on risk management, project management, and finance sponsored by various trade associations.

Q. **What are your responsibilities as Director of Commodity and Performance?**

A. I am responsible for the development and coordination of commodity sales programs for the NiSource gas distribution utilities. This includes the hedging strategy, risk management, and structuring of deals. In addition, I coordinate the department metric reporting.

Q. Have you previously testified before the Kentucky Public Service Commission or any other Kentucky regulatory commissions?

A. No.

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

A. I am responsible for the presentation and description of Columbia's proposed new tariff service offerings – Price Protection Service ("PPS") and Negotiated Sales Service ("NSS").

Q. Please summarize the elements of these new tariff services.

A. <u>PPS:</u>

- Available as a firm sales service option for residential, commercial, and industrial customers (less than 25,000 Mcf/year usage)
- Fixed or index price service for the commodity only
- Customer continues to be subject to applicable customer and distribution charges, including demand charges
- Price will be posted and once elected, it will be fixed for the customer for minimum one-year term, or the customer can select a monthly variable price tied to a known major index.
- No restriction on when a customer may elect
- Early termination fee of $10/month not to exceed $60
- Posted price may be changed by Columbia, at its discretion, for prospective elections

- Renewable by mutual agreement between customer and Columbia for successive one-year terms, at then-applicable posted price
- Risk of price variability borne by Columbia
- Columbia may enter into financial hedges to control its risk. Any hedges for PPS will be segregated from GCA hedges.
- GCA will continue to be credited for demand gas cost recoveries
- GCA also credited for cost of gas used to serve PPS customers, calculated based on the Weighted Average Cost of Gas ("WACOG"), consistent with the average day program

NSS:

- Optional firm or interruptible sales service for customers whose annual usage is greater than 25,000 Mcf/year
- Price is established by contract with customer and may be fixed or variable
- Early termination fee established by contract with customer
- Firm service option would pay applicable distribution charge
- Interruptible NSS would provide credit to GCA for use of interstate capacity assets based on a 100% load factor of Columbia Gas Transmission, LLC's ("TCO") Rate Schedule FTS
- Risk of price variability borne by Columbia
- Columbia may enter into financial hedges to control its risk. Any hedges for NSS will be segregated from GCA hedges.

Details concerning these elements will be provided later in my testimony.

Q. What is the difference between the traditional GCA service and the proposed services?

A. From a customer's perspective, the primary difference between PPS or NSS and Columbia's other sales services rates lies in the way that the gas is priced to the customer. PPS and NSS provide customers with choices that they can make to take more control over the management of their natural gas costs. In the case of PPS and fixed price NSS customers, this takes the form of locking in gas commodity prices for a specific period of time. PPS and NSS will provide these customers assurance with respect to what they can expect to pay for their natural gas during the term of the commitment. For variable price NSS, customers will have the ability to more closely tie their gas bills to a gas market index.

Q. What prompted Columbia to seek the authority to offer PSS and NSS?

A. Columbia believes that there is a customer demographic that would like to be able to opt out of the quarterly change to Columbia's commodity cost of gas. These new services would be selected as a replacement to Columbia's traditional gas cost adjustment ("GCA") mechanism and would offer the customer a set price for the commodity portion of their service. Most customers on Columbia's system who consume 25,000 Mcf or less per year would be eligible for PPS, while customers who consume more than 25,000 Mcf per year would be eligible for NSS.

Q. Why does Columbia believe there is a customer demographic interested in a fixed price commodity service?

A. Customer inquiries lead us to believe that there may be customer interest in these services. The general inquiry is usually in the form of the question as to why can't Columbia offer a guaranteed price that does not change every three months. In some cases the questions arise as a result of price spikes in the winter or other months of the year. In other cases, customers are interested in the ability to eliminate risk from their annual energy budget by paying a fixed price. In either case the ability for Columbia to offer a fixed price for the commodity portion of its sales service is something Columbia's customers desire and that Columbia is willing to offer.

Q. What is the difference from Columbia's perspective in these offers and its traditional GCA price?

A. To Columbia, PPS and NSS represent a means to offer customers an option that Columbia expects some to find appealing. To accomplish this, and shield the GCA from price risk in the event that the cost of gas differs from the price charged to the customers electing the service, Columbia is proposing that it absorb all of the associated price risk. Just as Columbia proposes to absorb any of the losses from these sales programs, Columbia will retain any profits from the programs.

Q. Will Columbia purchase specific streams of gas supply for the PPS and NSS customers?

A. No, Columbia will include the expected demand of its PPS and NSS customers in with demand of other sales customers as it develops its monthly and seasonal purchase plans. As stated, the reason a customer will choose these products is to change the price mechanism. To address the price alone, one need not change the physical approach of contracting for the physical gas purchases. Management of the pricing will occur by Columbia's application of risk management for which Columbia will use, in part, NYMEX natural gas futures contracts. Therefore, there is no need to stream a specific supply of gas to the PPS or NSS customers. This approach of using Columbia's pooled supplies, and crediting the cost of the PPS and NSS volumes back to the GCA, helps to ensure that management of the PPS and NSS volumes and prices do not have a detrimental impact on the prices of its traditional GCA priced customers.

Q. What are the major design elements of PPS & NSS?

A. There are four main elements of program design. Those elements are:

- Non-reconcilable fixed price offer
- Risk/reward philosophy
- Common pool of supply for gas supplies
- Commodity and demand credits to the GCA mechanism

Q. Please explain a non-reconcilable fixed price offer.

A. Simply put, if a fixed price offer has to be reconciled, then the customer will either receive a refund from or make a payment to Columbia at the end of the applicable period. This would be no different than the commodity price offered under Columbia's current purchased gas mechanism. If a customer elects PPS they will receive a fixed rate for the term of their contract. The customer will not see any reconciliation of that rate since Columbia takes all of the price risk.

The necessity for a refund or additional payment by the customer means two things. One, the fixed price offer is not truly fixed because at some point a reconciliation of costs versus revenues takes place. Two, the risk of any fluctuations in natural gas commodity prices are borne by the customer and not Columbia. By placing the risk of price changes on Columbia, customers can lock in a commodity price and not worry about price fluctuations during the contract period. [

Q. How will Columbia file the PPS fixed price?

A. The fixed prices will be filed with the Commission under the normal process for filing a tariff change, that is to say it will be filed 30 days in advance of the revised price taking effect. Our intent is to file the prices along with a petition for confidential treatment, and only make the price information publicly available once the Commission has approved the price. Any changes will be filed with the Commission in the same fashion, and would not take effect until approved by the Commission.

Q. Will Columbia only have one fixed price available at a time?

A. When each new price is filed it will be with the intention that the prior price will be closed when the new rate is approved.

Q. How will the PPS price offers be made to customers?

A. The PPS program will offer a fixed price that an eligible customer can select to replace the GCA portion of their bill. The fixed prices will be available on our website once approved by the PSC. Our call center will also have the currently available PPS rate. Columbia, from time to time, will use some advertising to inform customers about PPS.

Q. How often will the fixed prices change?

A. Our intention is to change the fixed prices infrequently. However, the potential for variations in the gas market could cause us to file a price change at any time.

Q. Will customers always be able to enroll in PPS?

A. No. It will take us 30 days to implement a new fixed price. Therefore, changes in gas prices could cause us to suspend enrollments for a period of time. If Columbia does suspend enrollments, we will post on the website that current enrollments are suspended and our call center will also be notified of the change should anyone call to inquire about PPS.

Q. How will a customer enroll in PPS?

A. Customers will have multiple options for enrolling in PPS. The Columbia website will have information on PPS, the current PPS price offer, the terms and conditions, and a secure area the customer can use to enroll. Customers will also have the option of using Columbia's existing call center to enroll or have their questions about PPS answered. From time to time Columbia could send direct mail to customers informing them of the program, the current price, and offer the opportunity to enroll by mail. Columbia will not seek recovery for the cost of this or any advertising.

Q. What is the minimum term for a PPS contract?

A. The minimum term for PPS will be for 12 months.

Q. What happens at the end of a PPS customer's contract?

A. At the end of the initial contract term, the customer will have the option to continue on PPS for another year at the currently available price or end their agreement and return to GCA service.

Q. How does a customer sign up for NSS?

A. NSS customers will have the ability to sign up in much the same way as the PPS customers. They will be able to initiate contact through the Columbia website or through the call center. Columbia will then work with them to establish a contract.

Q. Does NSS have the same minimum term as PPS?

A. Yes, NSS also has a one year minimum term.

Q. What happens at the end of the contract term for a NSS Customer?

A. Like PPS, a NSS customer will have the option of continuing on the rate or returning to sales service.

Q. Why would Columbia want to bear the risk associated with a fixed price program?

A. As designed and proposed, Columbia is willing to bear the risk of loss associated with the program if it is permitted to retain any upside reward.

Q. How does Columbia propose to bear the risk versus assigning risk to the gas cost adjustment mechanism?

A. There are two approaches to assigning the risk of a fixed price offer to Columbia versus the GCA mechanism. One is to purchase a specific gas supply (streaming) for PPS and/or NSS and the other is to utilize Columbia's common pool of gas supply for the proposed rates. Columbia has chosen to utilize the common pool of supply for providing service to PPS and NSS.

Q. What advantage(s) does the common pool of supply approach provide?

A. There are two distinct advantages to the common pool of supply approach. First, by not streaming its supply, Columbia eliminates the concern of using the lowest cost source of supply for PPS and NSS instead of assigning such costs to the GCA sales customers. Second, for gas supply purposes these customers are being treated no differently than other sales service customers. They are treated differently only as to price, and Columbia takes all price risk.

Q. Why is a common pool approach a key design element of these programs?

A. As proposed, these rates are sales service rates and the gas supply will be purchased by the same individuals buying supply for Columbia's other sales customers. This is consistent with planning, where Columbia would look at the entire pool of sales customers and not make a separation between the groups. Streaming, on the other hand, involves the identification and dedication of a specific gas supply to customers electing the service. To stream the gas to PPS and NSS they would then split the entire group into three groups and make separate purchases for identical time periods. This causes the streamed approach to be duplicative and to create unnecessary additional work. By using a common pool, this duplication of work is avoided.

Q. What steps will Columbia take to separate the costs of these services from the GCA?

A. Since Rates PPS and NSS are alternatives to the GCA, Columbia will provide credits to the GCA for gas costs that reflect the use of a common pool of gas supply. This will be accomplished by using Columbia's WACOG in calculating credits provided to the GCA by Rates PPS and NSS. The effect is to credit the GCA for commodity gas costs to serve PPS customers on the same average basis as GCA customers, thereby avoiding any subsidization of PPS service. The GCA credits will be described in detail later in my testimony.

With regard to PPS usage, Columbia proposes to use an "average day" ($1/365^{th}$ of a customer's projected annual usage) methodology. The average day approach recognizes that Columbia purchases gas for firm customers on a relatively consistent basis throughout the year and that storage is used to manage daily and seasonal swings in gas usage. By pricing out the average day volumes at the WACOG, the credits provided to the GCA are consistent with the gas supply costs incurred to serve GCA and PPS sales customers.

For usage under NSS, Columbia will calculate the credit to the GCA utilizing the customer's monthly sales volumes times the WACOG. By using monthly sales volumes, Columbia will provide credits to the GCA that reflect the fact that NSS monthly requirements were met by purchases within the month. Again, I will describe the credits provided to the GCA for NSS later in my testimony.

Q. How will Columbia manage the risk associated with changes in the price of natural gas?

A. Columbia will enter into financial hedges for the volumes associated with Rate PPS and NSS. None of the costs of these hedges will be charged to the GCA or included in Columbia's base rates.

Q. So far you have focused on the GCA. How will the Gas Cost Demand be treated for PPS?

A. This is one of the premier design features of the proposed services. PPS, as a firm sales service, will pay the same demand costs as GCA customers. Therefore, there is no subsidization by the GCA of PPS demand costs.

Q. What about demand costs for NSS service?

A. NSS customers will have several capacity (demand cost) options. The customers may elect firm capacity, and pay the same demand cost as firm sales customers. The customers may also elect a specified level of firm capacity, and pay the demand rates specified under Columbia's Standby Service Rate Schedule. I note that this is a rate currently available to larger transportation service customers who desire the ability to purchase gas up to a specified daily volume without interruption. Finally, the NSS customer may elect interruptible service. In that event, credits will be provided to the GCA for use of interstate FT to deliver supplies in the month. Columbia also is proposing that the GCA receive a further credit for use of FS assets. I will detail these credits later in my testimony.

GCA Credits

Q. Please explain the crediting mechanism to the GCA.

A. While the overall concept of providing credits to the GCA for PPS and NSS is similar, it is not identical. Therefore, I will explain each crediting calculation separately.

Rate PPS Credits to GCA

Columbia's decision to use the common pool of supply methodology and average day program for gas supplies for PPS requires that the rate provide a monthly credit to the GCA mechanism. The initial credit (an example is provided as Attachment EAE-1) to the GCA will be calculated in the following manner:

(Projected requirements) x (WACOG at the city gate)

- "Projected requirements" are defined as the annual estimated demand, divided by 365, multiplied by the number of days in the month.
- "WACOG at the city gate" is defined as the weighted average commodity cost of all purchases, excluding any purchases under fixed price commodity or financial hedge contracts entered into for GCA customers for which the price was determined more than thirty days before the beginning of the calendar month.

Since Columbia will be using the average day approach in determining the GCA credit, there will need to be a true up to the actual volumes used by the PPS customers. This true up will keep the GCA whole by making the credit to the GCA equal to the actual volumes used under PPS multiplied by the corresponding WACOG. This will not effect the customer's fixed rate, but rather will allow the GCA to be kept whole while the customer receives a non-reconcilable fixed rate. Columbia's proposed tariff provides for an annual true up each June calculated as follows:

(Actual Consumption – Average day volumes) x WACOG

An example of how this true up will work is provided as Attachment EAE-2 to my testimony.

NSS Credits to GCA

Based on the common pool of supply methodology, NSS will provide a monthly credit to the GCA to be calculated as follows:

(Monthly requirements) x (Monthly WACOG)

Q. Earlier, you mentioned that interruptible NSS would provide a demand credit based on the 100% load factor of TCO's firm transportation rate. Please explain why this is an appropriate basis for demand related costs to be credited to the GCA.

A. The 100% load factor rate is the "maximum rate" allowed by FERC for daily capacity releases. By using TCO's rate in this calculation, Columbia is providing no less value to the GCA than could be garnered by releasing the same capacity in the secondary market.

Q. Does Columbia anticipate needing to acquire incremental capacity for interruptible sales under NSS?

A. No. However, if required, Columbia commits that the cost any of such incremental capacity charged to the GCA will not exceed the demand cost credit provided from interruptible sales under NSS.

Program Administration

Q. How does Columbia plan to administer these services?

A. Columbia will administer these services with existing personnel. To the extent that personnel provide an administrative service related to these offerings, Columbia will charge those costs to the specific services causing the cost incurrence. In addition, costs to market the services will also be charged to the services. Moreover, Columbia is assuming the costs of risk management (hedging) these programs as part of its assumption of the risk of losses or of the potential for gain. Any costs of the gas hedges for the services will be excluded from the GCA or base rate recovery by Columbia.

Q. How would NSS price offers be treated?

A. All NSS price offers will be negotiated between Columbia and the customer. NSS customers will sign individual contracts which will contain the specifics of those negotiations.

Q. What is the purpose of the early termination fee under PPS?

A. Columbia will incur costs to hedge its risks for a given term, and the early termination fee is intended to compensate Columbia for customers that do not fulfill their obligations under the contract by leaving prior to the expiration of their term.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, however, I reserve the right to file rebuttal testimony if necessary.

Columbia Gas of Kentucky, Inc.

Illustrative Example of the
Proposed Credit to the GCA for PPS Program

Line No.	Date	PPS WACOG ($/Mcf)	PPS Customer Count	Average Day Volumes	Total PPS Average Day Volumes	Actual Volumes	Difference	PGCC Monthly Credit
		(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)=(4)-(5)	(7)=-(1)*(4)
	Year 1							
1	July Activity	$6.4932	3,800	12.5	47,500.0	32,000.0	15,500.0	$ (308,427)
2	August Activity	$7.7440	4,150	13.0	53,950.0	32,800.0	21,150.0	$ (417,789)
3	September Activity	$7.2602	4,225	12.7	53,657.5	66,400.0	(12,742.5)	$ (389,564)
4	October Activity	$5.7927	4,200	13.2	55,440.0	116,200.0	(60,760.0)	$ (321,147)
5	November Activity	$10.6035	4,200	13.1	55,020.0	71,400.0	(16,380.0)	$ (583,405)
6	December Activity	$9.1845	4,800	12.2	58,560.0	17,600.0	40,960.0	$ (537,844)
7	January Activity	$6.4765	4,650	12.8	59,520.0	38,700.0	20,820.0	$ (385,481)
8	February Activity	$9.0236	4,700	12.9	60,630.0	12,600.0	48,030.0	$ (547,101)
9	March Activity	$8.2924	4,600	12.7	58,420.0	16,400.0	42,020.0	$ (484,442)
10	April Activity	$8.3342	4,550	13.0	59,150.0	12,450.0	46,700.0	$ (492,968)
11	May Activity	$7.8988	5,000	13.5	67,500.0	20,000.0	47,500.0	$ (533,169)
12	June Activity	$7.9180	5,100	13.6	69,360.0	45,900.0	23,460.0	$ (549,192)

Columbia Gas of Kentucky, Inc.

Illustrative Example of the
Proposed Annual True Up Credit to the GCA for PPS Program

Line No.	Date	PPS WACOG ($/Mcf)	PPS Customer Count	Average Day Volumes	Total PPS Average Day Volumes	Actual Volumes	Difference	GCA Monthly Credit	Annual Adjust.	Total PGCC Credit
		(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)=(4)-(5)	(7)=-(1)*(4)	(8)=-(1)*(6)	(9)=(7)+(8)
	Year 1									
1	July Activity	$6.4932	3,800	12.5	47,500.0	32,000.0	15,500.0	$ (308,427)	$ (100,645)	$ (409,072)
2	August Activity	$7.7440	4,150	13.0	53,950.0	32,800.0	21,150.0	$ (417,789)	$ (163,786)	$ (581,574)
3	September Activity	$7.2602	4,225	12.7	53,657.5	66,400.0	(12,742.5)	$ (389,564)	$ 92,513	$ (297,051)
4	October Activity	$5.7927	4,200	13.2	55,440.0	116,200.0	(60,760.0)	$ (321,147)	$ 351,964	$ 30,817
5	November Activity	$10.6035	4,200	13.1	55,020.0	71,400.0	(16,380.0)	$ (583,405)	$ 173,685	$ (409,719)
6	December Activity	$9.1845	4,800	12.2	58,560.0	17,600.0	40,960.0	$ (537,844)	$ (376,197)	$ (914,041)
7	January Activity	$6.4765	4,650	12.8	59,520.0	38,700.0	20,820.0	$ (385,481)	$ (134,841)	$ (520,322)
8	February Activity	$9.0236	4,700	12.9	60,630.0	12,600.0	48,030.0	$ (547,101)	$ (433,404)	$ (980,504)
9	March Activity	$8.2924	4,600	12.7	58,420.0	16,400.0	42,020.0	$ (484,442)	$ (348,447)	$ (832,889)
10	April Activity	$8.3342	4,550	13.0	59,150.0	12,450.0	46,700.0	$ (492,968)	$ (389,207)	$ (882,175)
11	May Activity	$7.8988	5,000	13.5	67,500.0	20,000.0	47,500.0	$ (533,169)	$ (375,193)	$ (908,362)
12	June Activity	$7.9180	5,100	13.6	69,360.0	45,900.0	23,460.0	$ (549,192)	$ (185,756)	$ (734,949)
13	TME June							$ (5,550,530)	$ (1,889,312)	$ (7,439,841)

Annual Reconciliation

True-up occurs in June to make the credit to the PGC equivalent to the actual volumes less the sum of the average day volumes multiplied by the WACCOG for the 12 months ended June:

Sum of monthly credits to the GCA (Ln 13, Col 7)	($5,550,530)
Plus: Annual Adjustment (Ln 13, Col 8)	($1,889,312)
Total Annual Credit to the GCA	($3,661,218)