

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT
OF GAS RATES OF COLUMBIA GAS
OF KENTUCKY, INC.

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CASE NO. 2007-00008

VOLUME 7

DIRECT TESTIMONY

Columbia Gas of Kentucky
Case No. 2007-00008
Table of Contents
Volume 7

Tab	Filing Requirement	Volume	Description	Responsible Witness
			Policy, depreciation funding of CAP and main replacement program, areas covered by other witnesses, and elimination of merger order filing requirements	
Herbert A. Miller Jr.	Testimony	7		Herbert A. Miller Jr.
James M. Webb	Testimony	7	Accelerated main replacement program	James M. Webb
Edwin Humphries	Testimony	7	Accelerated main replacement program	Edwin Humphries
			Tariff changes, energy assistance program, and rate design, merger savings and rate mechanism	
Judy M. Cooper	Testimony	7		Judy M. Cooper
			Expense adjustments, rate base, and revenue requirement calculation	
Kelly L. Humrichouse	Testimony	7		Kelly L. Humrichouse
			Rate of return, capital structure, and cost of capital	
Paul R. Moul	Testimony	7		Paul R. Moul
Mark P. Balmert	Testimony	7	Revenue adjustments	Mark P. Balmert
Ronald D. Gibbons	Testimony	7	Cost of service study	Ronald D. Gibbons
William M. Gresham	Testimony	7	Sales volume/weather normalized	William M. Gresham
			Corporate allocations and allocation of merger transaction costs to CKY	
Susanne M. Taylor	Testimony	7		Susanne M. Taylor
Panpilas W. Fischer	Testimony	7	Taxes	Panpilas W. Fischer
John J. Spanos	Testimony	7	Depreciation studies	John J. Spanos
June M. Konold	Testimony	7	OPEB	June M. Konold

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia)
Gas of Kentucky, Inc.) Case No. 2007-00008

**PREPARED DIRECT TESTIMONY OF
HERBERT A. MILLER, JR.
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February 1, 2007

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COLUMBIA GAS OF KENTUCKY, INC.

1 **PREPARED DIRECT TESTIMONY OF HERBERT A. MILLER, JR.**

2 Q: Please state your name and business address.

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

5
6 Q: What is your current position and responsibilities?

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

11
12 Q: What is your educational background?

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

15
16 Q: Please describe your employment history.

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

1 From 1993 to 1998, I practiced law in Lexington as a partner in what is now the
2 firm of Stoll Keenon Ogden. My clients included financial institutions, utilities, real
3 estate developers, governmental entities and non-profit organizations. During this time
4 period, I also served as an adjunct professor at the University of Kentucky College of
5 Business and Economics teaching classes in the *Regulatory and Ethical Environment of*
6 *Business*.

7 From 1980 until 1993, I was the Senior Vice-President, General Counsel and
8 Corporate Secretary of First Security Corporation, a multi-bank holding company
9 headquartered in Lexington, Kentucky. In this position, I managed the legal, regulatory
10 compliance and loss control departments and was responsible for the SEC reporting and
11 disclosure functions.

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

15
16 Q: Have you previously testified before the Kentucky Public Service Commission or any
17 other Kentucky regulatory commissions?

18 A: While I have filed reports, submitted responses to regulatory inquiries and appeared as
19 counsel before the Commission in various matters, I have not testified as a witness before
20 the Kentucky Public Service Commission or other Kentucky regulatory commissions.

21

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

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

6

7 Q: Please briefly summarize the history and business of Columbia Gas of Kentucky and its
8 parent company, NiSource Inc. ("NiSource").

9 A: Columbia Gas of Kentucky began in 1905 as Central Kentucky Gas Company, with
10 producing wells in Menifee, Powell and Montgomery counties and franchise rights in
11 Lexington, Mt. Sterling and Winchester. In 1928 the company became part of the gas
12 system of Columbia Gas & Electric Corporation. The company's name was changed to
13 Columbia Gas of Kentucky, Inc. in 1958 and is now, following the merger of NiSource
14 and Columbia Energy Group in 2000, one of ten (10) natural gas local distribution
15 companies in the NiSource family of companies.

16 Columbia has been headquartered in Lexington, Kentucky since 1905 and our 134
17 employees now serve nearly 140,000 residential, commercial and industrial customers in
18 approximately 30 Kentucky counties and operate more than 2500 miles of natural gas
19 pipelines. This service area includes the communities of Ashland (and surrounding
20 communities), Cynthiana, Frankfort, Georgetown, Hindman, Inez, Irvine, Lexington,
21 Louisa, Maysville, Midway, Mt. Sterling, Paris, South Shore, Versailles and Winchester.

22 NiSource, headquartered in Merrillville, Indiana, is an energy holding company
23 whose subsidiaries provide natural gas, electricity and other products and services to

1 approximately 3.8 million customers located within a corridor that runs from the Gulf
2 Coast through the Midwest to New England. NiSource is the successor to an Indiana
3 corporation organized in 1987 under the name of NIPSCO Industries, Inc., which
4 changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition
5 of the Columbia Energy Group (“CEG”) on November 1, 2000, NiSource became a
6 Delaware corporation registered under the Public Utility Holding Company Act of 1935
7 (now known as the Public Utility Holding Company Act of 2005). NiSource is also
8 subject to the jurisdiction of the Securities and Exchange Commission (“SEC”) and is
9 traded on the New York Stock Exchange with the symbol “NI.” The NiSource core
10 operating companies engage in natural gas transmission, storage and distribution, as well
11 as electric generation, transmission and distribution. Its natural gas distribution
12 operations serve at retail over 3 million residential, commercial and industrial customers
13 with approximately 57,000 miles of pipeline in 9 states (Indiana, Kentucky, Maine,
14 Maryland, Massachusetts, New Hampshire, Ohio, Pennsylvania and Virginia).

15 The NiSource gas distribution companies are: Bay State Gas Company, Northern
16 Utilities, Inc. (a subsidiary of Bay State), Columbia Gas of Kentucky, Columbia Gas of
17 Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of
18 Virginia, Kokomo Gas and Fuel Company, Northern Indiana Fuel and Light Company
19 and Northern Indiana Public Service Company.

20
21 Q: Please summarize Columbia’s major objectives in this proceeding.

22 A: Columbia’s filing today provides the information necessary to approve several initiatives
23 that Columbia believes are required to enable it to continue to provide safe and reliable

1 natural gas service at the lowest reasonable cost to its customers. Columbia proposes an
2 Accelerated Main Replacement Program (“AMRP”) to recover the costs to accelerate the
3 replacement of approximately 540 miles of its unprotected (bare) steel and cast iron
4 infrastructure over a period of 20 years. This request for the approval of a mechanism to
5 expediently recover the required additional capital outlay will allow Columbia to avoid
6 the adverse effects of corrosion in its system and reduce the regulatory expense of more
7 frequent rate increase requests. To overcome its operating revenue deficiency, Columbia
8 seeks an increase in operating revenues of \$12,645,522 which represents a 7.99%
9 increase from the 12-month period ending September 30, 2006. Columbia’s request
10 includes certain adjustments in certain miscellaneous charges, such as returned check fees
11 and reconnection fees to adequately recover the costs associated with these activities and
12 various organizational amendments to its tariff.

13 Columbia is also introducing important regulatory concepts in this filing, such as
14 the issues of declining customer usage and growth and the challenges they present for
15 natural gas distribution utilities. In that vein, Columbia is proposing an adjustment in the
16 Minimum (or Base Rate) Charge (and will refer to it as a “Customer Charge”), which
17 concerns the recovery of the fixed costs required to ensure that natural gas service is
18 available to the customer, and a mechanism for the accounting treatment of post in-
19 service carrying charges, called PISCC, by recognizing certain costs as a regulatory asset.

1 Q: Please give a summary explanation of the proposed Accelerated Main Replacement
2 Program (“AMRP”).

3 A: As described in greater detail by Columbia witness Webb, Columbia is facing
4 accelerating corrosive deterioration of its unprotected steel and cast iron mains and other
5 infrastructure facilities. By “unprotected” I mean that the facilities are without cathodic
6 protection and susceptible to corrosion (Mr. Webb will address this with more specificity
7 in his testimony). This situation requires Columbia to accelerate its replacement of these
8 affected facilities. Columbia proposes to invest approximately \$9.9 million annually
9 during a period of 20 years to accelerate replacement of these facilities. This amount
10 represents Columbia’s annual investment in certain infrastructure as described in the
11 testimony of Columbia witness Webb.

12
13 Q: Is there a precedent for the Commission’s approval for this type of program for the
14 acceleration of replacement of unprotected infrastructure?

15 A: Yes. The Commission approved a request of The Union Light, Heat and Power
16 Company (ULH&P) in Case No. 2001-092 in an Order dated January 31, 2002 for an
17 initial three-year term, and approved continued use of the rider through the remaining
18 years of the AMRP in Case No. 2005-00042 in an Order dated December 22, 2005.
19 ULH&P is now called Duke Energy Kentucky, Inc. and will hereafter be referred to as
20 Duke Energy. The Duke Energy program addresses the replacement of 150 miles of
21 unprotected cast iron and steel mains over a 10-year period. In comparison, Columbia
22 proposes a program of replacing approximately 540 miles of such facilities over 20 years.

23

1 Q: Does the Commission have the statutory authority to approve such a program?

2 A: Yes. Kentucky Revised Statutes Chapter 278.509 provides that

3 “Notwithstanding any other provision of law to the contrary, upon application by a
4 regulated utility, the Commission may allow recovery of costs for investment in natural
5 gas pipeline replacement programs which are not recovered in the existing rates of a
6 regulated utility. No recovery shall be allowed unless the costs shall have been deemed
7 by the Commission to be fair, just and reasonable.”
8

9 Q: Please provide a general description of the AMRP recovery mechanism.

10 A: As described in greater detail by Columbia witness Judy Cooper, Columbia proposes a
11 tracking mechanism to recover the costs of this system improvement on a more timely
12 basis than provided by the traditional ratemaking process. The cost recovery mechanism
13 is contained in Columbia’s proposed tariffs and identified as the Accelerated Main
14 Replacement Program Rider (Proposed Tariff Sheet No. 59). Specifically, Columbia
15 proposes to annually submit to the Commission its proposed construction plans for the
16 coming year, the actual construction results and corresponding costs for the prior 12-
17 month period and a calculation to derive a monthly customer charge and a MCF charge.
18 If approved, Columbia will apply the charges to its customers’ bills. The details of how
19 the tracker is designed to work are included in the testimony of Columbia witness
20 Cooper.

21
22 Q: What benefits will result from the approval of the AMRP?

23 A: The AMRP will result in an accelerated replacement of approximately 540 miles of
24 Columbia’s pipeline system that are not adequately cathodically protected at a faster rate
25 than Columbia’s process of identifying and replacing the worst performing segments of
26 the system each year. Columbia witness Webb’s testimony describes in detail the safety

1 and reliability benefits of this program. Similar to the Duke Energy program, if there are
2 inside gas meters moved to outside locations at the same time the unprotected lines are
3 replaced, we propose to include this as part of the AMRP. Beyond the features of safety
4 and pipeline reliability, the AMRP will also permit Columbia to reduce costs by
5 identifying geographic areas for more efficient construction scheduling and work and by
6 planning fewer disruptions in traffic flow and to customers. Lastly, by the approval of
7 the AMRP, Columbia, and its customers, will avoid the extensive regulatory costs
8 associated with a series of more frequent rate filings to recover these replacement costs.
9 KRS 278.509 recognizes that programs such as proposed today enhance regulatory
10 efficiency and can avoid the costs of repeated rate filings while preserving economy and
11 efficiency for the Commission and its staff.

12
13 Q: What are the primary factors causing the revenue deficiency?

14 A: The last time the Commission approved a rate increase for Columbia was in Case
15 Number 1994-179. That case permitted a gradual increase in rates with the final rate
16 increase from that case occurring in October of 1996. Since 1996 Columbia has invested
17 approximately \$94 million to serve its customers in Kentucky. Over this same period
18 Columbia absorbed increased costs for labor and employee benefits, materials, supplies
19 and other general operating and maintenance expenses. Finally, as explained in the
20 testimony of Columbia witness William Gresham, Columbia has experienced a
21 significant decline in average customer gas usage and a decline in its overall number of
22 customers. This experience directly impacts Columbia's ability to continue to meet its
23 service obligations to its remaining customer base.

1 Columbia's 2002 rate case following the NiSource/CEG merger reduced rates by
2 approximately \$7.8 million. Since then Columbia has experienced a significant increase
3 in rate base. The rate base level in Columbia's 2002 rate case was \$128.6 million, and it
4 has grown to \$171.4 million (See Schedule B-1, Sheet 1 of 1). The key drivers in the
5 increase are net plant and gas in underground storage. Columbia's net plant increased
6 \$15.6 million and gas in underground storage increased \$35.9 million from \$11.9 million
7 to \$47.8 million on a thirteen month average basis (See Schedule B-5, Sheet 1 of 1). The
8 increase in gas in underground storage is due to the significant increase in the cost of gas
9 that the industry has experience since 2001.

10
11 Q: What is Columbia doing to attempt to offset the impact of these items?

12
13 A: Since the 2002 rate case, Columbia has been able to hold down its Operations and
14 Maintenance ("O&M") costs to offset the impact. Unadjusted O&M expenses have
15 *decreased* by nearly 11%, down from \$28.6 million to \$25.5 million since Columbia's
16 2002 rate case. This decrease in Columbia's O&M costs compares favorably to the
17 *increase* in the Consumer Price Index (CPI) of 10.152% from March of 2003 to
18 September of 2006 (as measured by the U.S. Bureau of Labor Statistics for the U.S. city
19 average).

20 Also, as part of this case, Columbia is proposing a program that will enable
21 customer growth by allowing the recovery of certain costs associated with system
22 expansion to be shared over an expanding customer base. Under this proposal, Columbia
23 is asking the Commission to allow Columbia to record certain charges associated with

1 new development extensions as a regulatory asset. Columbia witness Judy Cooper will
2 provide a more complete description of this proposal.

3 Columbia recognizes that customer growth is a combination of both price and
4 service. In addition to controlling costs, Columbia has enhanced its New Business
5 function by recently adding a new employee in Lexington. This individual has more than
6 17 years of experience with Columbia and is dedicated to serving applicants for new
7 business throughout our territory and looking for customer growth opportunities.

8
9 Q: How did Columbia determine the revenue requirement necessary for this case?

10 A: As described in the testimony of Columbia witness Humrichouse, Columbia reviewed its
11 costs to serve its customers, using a historical test period ending September 30, 2006, pro
12 formed and adjusted for known and measurable changes. Columbia then compared this
13 cost to serve to its test year revenues, as adjusted, which produced a revenue deficiency,
14 and the corresponding revenue requirements that Columbia will require to make up this
15 deficiency with a fair rate of return on the investments devoted to serving the public.

16
17 Q: Why is the proposed rate increase necessary to eliminate the revenue deficiency?

18 A: Columbia's current rates do not provide the opportunity to recover its costs to serve
19 customers, including a reasonable rate of return on the capital invested to provide
20 distribution service to the public. The revenue deficiency amounts to \$12,645,522 per
21 year. Proposed rates have been developed to cure this deficiency and Columbia witness
22 Moul will support Columbia's rate of return on common equity in his direct testimony.

1 Q: What portion of a customer's monthly bill will be impacted by the proposed rate changes
2 in this filing?

3 A: The affected portions of a customer's monthly bill are the Minimum Charge (proposed in
4 this case to be called the Customer Charge) and the Gas Delivery Cost (these components
5 are also sometimes collectively referred to as the gas delivery charges). These
6 components are two of the three primary parts of a customer's bill and typically amount
7 to approximately 25% to 30% of a customer's total monthly gas bill. These two
8 components are charges for having natural gas available to customers, including main
9 installations, line inspections, repair and maintenance, customer service, emergency
10 services and other operations. The largest component of a customer's bill, the Gas
11 Supply Cost, is not affected by the request in this case. The Gas Supply Cost is the
12 amount paid for the natural gas commodity itself and its transportation along interstate
13 pipelines and storage. It is adjusted quarterly to reflect market conditions and passed on
14 to customers at cost without any markup. Again, this portion of the bill is not affected by
15 this request.

16
17 Q: What was Columbia's overall return during the historical test year in this case?

18 A: After eliminating non-base rate items, Columbia's overall rate of return was 4.26% (See
19 Schedule C, Sheet 1 of 1) for the period ending September 30, 2006, the historical test
20 period for this case.

21

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

3 A: Mr. Moul's testimony states that Columbia's overall return should be 8.71% and, after
4 stating a range of 11.25% to 11.75%, concludes that its rate of return on common equity
5 should be 11.50%.

6

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

8 A: Columbia's current rates were approved by the Commission in its Order dated December
9 13, 2002 (Case No. 2002-00145), which, following a Joint Stipulation and
10 Recommendation, called for a reduction in Columbia's base rates to result in a decrease
11 in annual operating revenues of \$7,800,000 effective March 1, 2003. In that case,
12 Columbia had originally requested the Commission to adjust its rates to produce
13 additional annual revenues of \$2,503,221, or approximately 2.3%.

14

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

17 A: The case was settled and the parties submitted to the Commission a stipulated revenue
18 decrease. The Commission approved the stipulated revenue decrease, and as a result,
19 there is no authorized rate of return in the Order of December 13, 2002.

20

21 Q: What have been Columbia's objectives regarding rate cases?

22 A: Prior to Columbia's last base rate increase in 1996, I have been advised that Columbia
23 was a frequent filer of rate cases. Since 1996, and in a more competitive energy market,

1 Columbia has employed other means such as comprehensive cost control measures to
2 attempt to meet its earnings objectives rather than filing rate cases. Since 1996,
3 Columbia's only rate case was Case No. 2002-00145, which resulted in Columbia's
4 revenue decrease effective March 1, 2003. That case was filed by Columbia as a result
5 of its commitment set forth in the Commission's Order in Case No. 2000-129 dated June
6 30, 2000, approving the merger of NiSource and the Columbia Energy Group.

7
8 Q: Please describe areas since 2003 in which Columbia has improved its operations and
9 service while taking cost control steps to avoid rate cases?

10 A: Columbia has organized its operations and invested significantly in technology to
11 improve service and control costs in a number of areas. The following are examples of
12 these efforts. While both our service technicians (those employees who repair service
13 lines, test meters, make customer connections and light gas appliances) and our "plant"
14 employees (those employees who install and repair mains, regulators and other
15 underground facilities) live and work throughout Columbia's service territory, the
16 scheduling for plant operations is now centralized in Lexington. This allows our
17 supervisory staff to better identify problem areas in our system, and predict, adjust and
18 distribute employee workloads to address main inspections, repairs and leak inspections.
19 In addition, our highest grade level field employees are now trained for both plant and
20 service work. This allows for more efficient responses and allocation of human
21 resources and reduces overtime.

22 Since 2003 Columbia has installed mobile data terminals ("MDTs") in the trucks
23 of its plant personnel (service technicians have used MDTs since before 1996). Using

1 this communication technology, these Columbia employees can begin their work day by
2 going directly to the job site and can be re-directed in the field to respond to emergency
3 calls and other priorities more quickly and reduces the potential for overtime work.
4 Columbia's system maps have also now been installed on the MDTs. Our Field
5 Operations leaders ("FOLs") use their MDTs as computers and have available in their
6 vehicles all of the Columbia data as if they were at their desks. In 2006 we began a
7 program of monthly telephone conferences between our FOLs and our customer call
8 center to identify and resolve issues related to both system-wide and customer-specific
9 problems. In addition to the daily communication that occurs on specific issues, this
10 program promotes a sharing of knowledge and information for improved customer
11 service.

12
13 Q: What steps has Columbia taken to promote quality control over its improved services?

14 A: The independent public opinion survey firm of Wilkinson & Associates conducts random
15 sample telephone interviews of customers who have had interactions with Columbia
16 through its customer call center. The survey asks customers to rate their experience with
17 both call center representatives and field service personnel. Customers are asked about
18 the level of the employee's skill and knowledge, his or her courteousness, timely
19 response and overall performance. Poor responses generate "red flag" reports that are
20 reviewed monthly with Columbia's Field Operations Leaders and trends are identified for
21 corrective action. Since my appointment date of September 1, 2006, I have made it a
22 priority to personally review the survey results and other customer service issues with our

1 call center personnel, our local staff in Lexington and our field teams throughout our
2 service territory to address problems and improve our customer service

3
4 Q: Has Columbia compromised service, safety or reliability while controlling costs?

5 A: Absolutely not. Columbia will not compromise on those areas. Its request for an
6 Accelerated Main Replacement Program (AMRP) in today's filing is an example of a
7 forward looking plan to serve its customers safely into the future. I would also direct
8 your attention to the testimony of Columbia witness Webb for an explanation of
9 Columbia's safety record.

10
11 Q: Columbia proposes adjustments in various fees and charges in its filed tariffs. Please
12 briefly explain these changes.

13 A: Since its last rate increase 10 years ago, Columbia has experienced increased costs in
14 performing certain services and handling certain transactions as part of providing
15 customer service and for which the current amount is insufficient to cover the costs
16 associated with the services. The fees and charges outlined in this response are those
17 which the rate-making process has historically identified as costs that should be borne by
18 those specific customers using the service or causing the cost to be incurred, rather than
19 being allocated among all ratepayers. While Columbia witness Cooper will detail these
20 changes, the following are two examples:

- 21 (a) an increase to the fee for Reconnections of Service resulting from disconnections
22 due to nonpayment of bills or violations of Columbia's rules and regulations from
23 \$15 to \$55.00.

1 (b) an increase to the Returned Check Fee from \$8 to \$15.00. This cost includes the
2 labor and equipment necessary to make attempts to reach the customer, issue new
3 termination orders, and enter the appropriate computer codes for processing the
4 transactions.

5
6 Q: Please summarize the proposed Customer Charge and the proposed changes to the Gas
7 Delivery Charges.

8 A: Columbia proposes to change its residential rate design from the existing term referred to
9 as "Minimum Charge" to a term called a "Customer Charge" and proposes to lower the
10 volumetric rates associated with the gas delivery charge. Please refer to the testimony of
11 Columbia witnesses Gibbons and Cooper for a complete explanation. The adjustment in
12 the Customer Charge is a closer reflection of the actual, non-usage sensitive costs to
13 provide service to customers and will allow Columbia the opportunity to earn a fair
14 return. Customers seeking ways to conserve energy will continue to be able to affect the
15 size the largest portion of their gas bill -- the cost of the gas commodity itself -- by
16 controlling the volume of gas they purchase, the efficiency of the appliances they use and
17 the extent to which they insulate their homes or businesses. Energy assistance funding,
18 payment plans and budget billing are available for customers who want or need financial
19 assistance or other planning to pay their bills.

20
21 Q: Does Columbia propose any changes in its energy assistance funding programs?

22 A: No. Columbia, its shareholders, employees and customers will continue to support
23 several forms of energy assistance funds, including WinterCare and the Energy

1 Assistance Program, which are administered by the Community Action Council. This
2 support totals approximately \$675,000 annually. In addition, federal programs such as
3 the Low-Income Home Energy Assistance Program (“LIHEAP”) are available for
4 families with income below 150% of the federal poverty level.

5
6 Q: Does Columbia propose any changes to its customer CHOICE program?

7 A: No. At December 31, 2006 there were 29,310 Columbia customers participating in the
8 CHOICE program. This program allows customers to choose to purchase their gas
9 supplies from an unregulated third party supplier at the rate agreed upon by the customer
10 and the third party supplier.

11
12 Q: Please introduce Columbia’s witnesses and generally describe their testimony.

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

- 15 • James M. “Mike” Webb: who will present testimony regarding the Accelerated
16 Main Replacement Program (AMRP), the safety and reliability of our pipelines and
17 other operational issues;
- 18 • Edwin Humphries: an expert witness from Stone & Webster Management
19 Consultants, Inc., who will support the independent review of Columbia’s AMRP;
- 20 • Judy Cooper: who will present testimony regarding tariff modifications, the AMRP
21 recovery program and the program regarding the accounting treatment of the post
22 in-service carrying costs (PISCC);

- 1 • Kelly Humrichouse: who will present testimony regarding support for the revenue
2 requirement request;
- 3 • Paul Moul: an expert witness who will provide testimony concerning the
4 appropriate rate of return for Columbia;
- 5 • Mark Balmert: who will present testimony regarding various billing determinants;
- 6 • Ron Gibbons: who will present testimony to support Columbia's rate design and
7 class cost of service;
- 8 • William Gresham: who will present testimony related to sales volumes and weather
9 normalization as well as customer usage and growth;
- 10 • Susan Taylor: who will present testimony about the level of service charges from
11 the NiSource Corporate Services Company;
- 12 • Panpilas Fischer: who will present testimony regarding tax issues;
- 13 • John Spanos: an expert witness who will provide testimony regarding the
14 depreciation study for Columbia; and
- 15 • June Konold: who will present testimony regarding the request for the accounting
16 treatment of the expenses for pensions/OPEBs and PSICC.

17

18 Q: Does this complete your Prepared Direct testimony?

19 A: Yes, subject to my ability to respond as necessary to issues raised in discovery or on
20 rebuttal.

Columbia Exhibit No. _____.

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PREPARED DIRECT TESTIMONY OF
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February 1, 2007

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COLUMBIA GAS OF KENTUCKY, INC.

1 Q: Please describe your membership in, or affiliation with, any industry organizations.

2 A: My industry affiliations include(d) the National Association of Corrosion Engineers
3 (“NACE”). I have been active in the Kentucky Gas Association (“KGA”) serving on the
4 KGA Education Committee (late 80’s early 90’s) and conducted Corrosion training for
5 the KGA. I also served as Secretary and Chairman of the Kentucky Corrosion
6 Coordinating Committee during parts of this timeframe. Through parts of the 90’s, I
7 served on the Board of Directors for Kentucky Underground Protection Inc..

8

9 Q: What is the purpose of your testimony today?

10 A: I will describe Columbia Gas of Kentucky’s distribution system, its historic operating
11 performance; and its proposed Accelerated Main Replacement Program (“AMRP”). In
12 addition to my testimony, Columbia has retained Edwin Humphries of Stone & Webster
13 Management Consultants Inc., an energy consulting firm, to render an independent
14 opinion regarding the appropriateness of an AMRP.

15

16 Q: Please summarize your testimony.

17 A: I first provide some background on Columbia’s natural gas distribution system. Followed
18 by an explanation of Columbia’s strong operational and maintenance history, and I
19 explain why Columbia’s ability to manage leakage in its system cannot maintain pace
20 with the level of deterioration in its unprotected steel mains and services.¹ It is these
21 facilities that require replacement through the AMRP. The following section describes
22 the need for the AMRP and how Columbia’s aging unprotected steel facilities are

¹ The terms “bare steel”, “unprotected coated steel” and “unprotected steel,” as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

1 progressively experiencing corrosion, pitting and rusting. These facilities must now be
2 replaced, in spite of Columbia's strong record of leak surveying, maintenance and repair
3 of these facilities.

4
5 Q: Please describe Columbia's distribution system.

6 A: Columbia Gas of Kentucky was incorporated in 1958 from consolidations over time of
7 many companies. These companies include Central Kentucky Natural Gas Company,
8 Lexington Gas Company, Huntington Gas Company, Frankfort Kentucky Natural Gas
9 Company, United Fuel Gas Company, Inland Gas Company, and Limestone Gas. As a
10 result of these combinations, Columbia's distribution system consists of many types of
11 pipe. Attachment 1 breaks down Columbia's infrastructure utilized to deliver natural gas
12 to nearly 140,000 residential, commercial, and industrial customers.

13
14 Q: What geographic areas does Columbia serve today?

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

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

2 A: Columbia's distribution infrastructure constitutes the final step in the delivery of natural
3 gas to customers from the producing regions of the southern United States and eastern
4 Kentucky. Columbia distributes natural gas by taking it from delivery points (or "city
5 gates") along interstate and intrastate pipelines, then transporting it through over 2,500
6 miles of relatively small-diameter distribution main and nearly 140,000 services that
7 network underground between and through cities, towns and neighborhoods in order to
8 meet the demands of residential, commercial and industrial end-use customers. Columbia
9 takes title of the natural gas commodity at the city gate and then steps down the
10 transmission pressure to local distribution pressure, and in some cases, adds an odorant
11 known as mercaptan to the natural gas before it is put into the distribution system. The
12 gas then goes into the Columbia distribution system where the pressure is often further
13 reduced to delivery pressure in a series of district regulator stations, before being
14 delivered to each customer. Once the gas is delivered on the customer's side of the meter,
15 it is owned by the customer and becomes the responsibility of the customer. In sum,
16 Columbia's distribution system moves relatively small volumes of natural gas at lower
17 pressures over shorter distances to a far greater number of individual users than its
18 interstate pipeline counterparts.

19
20 Q: Does Columbia meet or exceed state and federal requirements for operating its natural
21 gas system?

22 A: Yes. Columbia performs numerous safety related inspections and tests of its facilities
23 according to the U.S. Department of Transportation ("DOT") and the Kentucky PSC

1 regulations. In particular, DOT Part 192.723 requires operators to conduct comprehensive
2 leakage surveys in business districts at intervals not exceeding fifteen (15) months, but at
3 least once per calendar year. In non-business districts, DOT requires leak surveys at
4 intervals not exceeding five (5) years unless the pipes involved are unprotected steel, in
5 which case it is every three (3) years

6
7 Q: In what way does Columbia manage or classify its leak backlog and repairs?

8 A: Columbia classifies each gas leak according to its severity: Grade “1”, Grade “2
9 Priority”, Grade “2” or Grade “3”. A Grade “1” leak is hazardous and requires immediate
10 remediation and repair. A Grade “2 Priority” gas leak is a non-hazardous leak but
11 requires attention within a few days. A Grade “2” gas leak is non-hazardous at the time of
12 detection, but requires a scheduled repair based on the potential for becoming a hazard.
13 Although Columbia’s procedures allow for up to 15 months to repair these leaks, grade 2
14 leaks are typically repaired within 2 months. A Grade “3” gas leak is defined as “non-
15 hazardous at the time of detection and can be reasonably expected to remain non-
16 hazardous.” Grade “1”, Grade “2 Priority” and Grade “2” leaks must be reported to the
17 DOT, however Grade “3” leaks are typically not reported to the DOT in the annual DOT
18 7100 system reports. These gas leak classifications are defined in the Gas Piping
19 Technology Committee (“GPTC”) ANSI Z380.1 “Guide for Gas Transmission and
20 Distribution Piping Systems.” The Guide is commonly utilized by gas operators and state
21 pipeline regulators, including the Commonwealth of Kentucky, as an interpretation of
22 “DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By
23 Pipeline: Minimum Federal Safety Standards.”

1 Q: Please discuss Columbia's experience with service interruptions.

2 A: Columbia's Service Outage reports indicate a consistent reduction in the number of
3 multiple customer outages. In fact, during 2005, Columbia experienced only 2 instances
4 with multiple customer outages.

5

6 Q: Please discuss Columbia's emergency response performance.

7 A: Even with Columbia's large geographic service territory, our emergency response efforts
8 continue to be strong. Approximately 88% of our priorities are responded to in less than
9 45 minutes. Columbia has maintained its commitment to a safe and reliable system for its
10 customers.

11

12 Q: What kinds of pipe have been installed in the Columbia Gas of Kentucky system?

13 A: As stated earlier, the system comprises many different types of pipe. From the late 1800s
14 to the 1950s, Columbia, its predecessor companies and the rest of the gas industry
15 installed cast iron, wrought iron and bare steel throughout the early distribution systems.
16 Cast iron and wrought iron were among the first materials available, and was the pipe of
17 choice in the late 1800s and early 1900s. Cast iron had the advantage in that it was
18 relatively strong and was easy to install. However, it was vulnerable to breakage from
19 ground movement when the soil beneath the pipe or to its side was disturbed and pressure
20 exerted on the pipe, it could crack. Further, cast iron pipe utilized the bell and spigot joint
21 method to join each section of pipe. This joint method is prone to leakage. Finally, it was
22 determined that cast iron pipe was unsuitable for long-distance transportation of gas
23 because it was unable to withstand high pressures.

1 Q: How did the industry react to the problems present with the use of cast iron?

2 A: By the 1920s, the industry had adopted steel and wrought iron piping for mains. These
3 were deemed to be stronger than cast iron and able to withstand greater pressure. During
4 this time, bare steel and wrought iron began replacing cast iron pipe as the material of
5 choice for building a natural gas distribution system. During the post-World War II
6 construction boom, Columbia installed a significant amount of bare steel mains and
7 services. Bare steel is steel pipe that has no exterior coating. The use of bare steel and
8 wrought iron was common until the 1950s and 1960s when the industry began to realize
9 that despite its strength, bare steel was subject to on-going deterioration of pipe wall from
10 galvanic corrosion.

11

12 Q: Are there more safety and reliability risks associated with the use of bare steel and cast
13 iron?

14 A: Yes, bare steel pipe is subject to galvanic corrosion, which reduces the wall thickness and
15 increases the risk of leakage or fracture. Cast iron mains are more susceptible to being
16 pulled apart or to leakage at the joints due to surface conditions such as traffic, soil
17 subsidence and movement in the soil from freezing or drought conditions, and
18 construction activity. Bare steel and cast iron are thus subject to leaks at a greater rate
19 than cathodically protected coated steel or polyethylene mains, leading to higher
20 operating and maintenance expenses, greater line losses, and safety and reliability risks.

21

22

23

1 Q: Explain the process of corrosion.

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

- 7 1. Dissimilar metals (metal surfaces with different electrical potentials);
- 8 2. An electrical contact between the metal surfaces with dissimilar electrical
9 potentials; and,
- 10 3. Both surfaces must be in contact with an electrolyte (a non metallic
11 conductor of electricity such as soil).

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

16 The requirements for galvanic corrosion to occur exist on all buried steel
17 pipelines. Electrical potential differences exist between the surfaces of individual joints
18 of steel and can exist on the same section of pipe due to a variety of factors such as
19 handling, manufacturing inconsistencies, and joining techniques. Additionally other
20 metals having varying electrical potential are necessary to build a pipeline such as joint
21 couplings, welding rod steel, and tap fittings. All underground pipelines are surrounded

1 by soil which is an electrolyte. Because all the requirements exist in buried pipelines,
2 galvanic corrosion, starts as soon as the newly constructed pipeline is backfilled and
3 continues without interruption until anodic areas of the pipeline are consumed by the
4 process. The speed at which this process takes place is controlled by a number of factors,
5 the relationship in size of anodic areas to cathodic areas along the pipeline, the magnitude
6 of difference in the electrical potential of metals used to build the pipeline, and the
7 electrical resistance of the electrolyte (or soil) in contact with the surfaces of the pipeline.

8 Columbia's first generation of steel piping systems, bare steel; have been
9 continuously subjected to the deteriorating effects of galvanic corrosion since their first
10 installation in the early 1900s. These pipelines have been in operation for up to 100 years.

11 Q: What did the industry do to combat the problem of corrosion in bare steel?

12 A: LDCs began using coated steel. Coated steel refers to steel pipe with an exterior dielectric
13 coating. The coating is intended to electrically isolate the steel from the surrounding soil
14 (electrolyte) to remove one of the requirements for galvanic corrosion to take place.

15
16 Q: Did the use of coated steel solve the problem?

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

23

1 Q: What material replaced bare steel and coated steel?

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

4

5 Q: What is “cathodic protection?”

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

18

19 Q: Has the industry further improved the functionality of its piping since the introduction of
20 cathodically protected steel?

21 A: Yes, it has. The major advancements have been in development of better pipeline
22 coatings and joint coatings. Coatings are now available with better adhesion to the pipe,
23 more durability in the underground environment, and better handling capabilities. Joint

1 coatings have improved in the same areas and the applications processes are much
2 improved. Cathodically-protected coated steel has all the advantages of steel in terms of
3 strength and, because of its impressed electrical current, is highly corrosion resistant.
4 However, it is more costly to purchase, install, and maintain than the next generation of
5 pipe, which is plastic or polyethylene.

6
7 Q: What are the benefits of plastic pipe?

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

12
13 Q: Does plastic pipe have any drawbacks?

14 A: The single significant drawback to plastic is its relative vulnerability to third party
15 damage compared to cast iron or steel. Cast iron and steel piping have greater tensile
16 strength and a greater resistance to external impact. As a result, excavators who do not
17 dig by hand (as required by Kentucky One-Call) in the vicinity of plastic facilities are
18 more likely to damage plastic pipe. However, Columbia's damage prevention program
19 meets or exceeds industry standards and significantly reduces the risk of damage to its
20 infrastructure.

21

1 Q: How does Columbia install pipe in its underground distribution system?

2 A: The installation of natural gas distribution pipe usually requires the excavation of a
3 trench, often under or adjacent to a public street into which the pipe is laid. Sometimes,
4 various boring techniques can be performed to minimize the surface disruption, but this
5 technology must be carefully chosen. Because of the need to excavate, installation of
6 natural gas distribution pipe can be inconvenient for residents, business owners and
7 municipalities.

8

9 Q: Why does Columbia need an AMRP?

10 A: As stated earlier, Columbia's distribution system consists of a large amount of
11 unprotected bare steel and cast iron mains and services that are continuously subjected to
12 corrosion. Although the replacement of the unprotected steel and cast iron will require
13 substantial financial and operational commitment by Columbia, the AMRP is being
14 implemented in the best interests of our customers. This program will further improve
15 Columbia's safety and reliability record by significantly reducing our leak incident rates
16 and enable much higher efficiencies to be achieved in the long term.

17

18 Q: Please describe the manner in which Columbia has been addressing the replacement of its
19 unprotected steel facilities.

20 A: Columbia has continuously replaced and retired unprotected steel in its system since the
21 late 1960s and early 1970s. Columbia currently replaces pipe segments following an
22 analysis of the segment's historical leak rate, along with a number of other internally
23 defined risk criteria. Columbia attempts to identify the likely worst performing segments

1 and replaces those each year. These may be wrought or cast iron; they may also be bare
2 steel; they may be unprotected coated steel (“UPCS”). If the base metal is steel and the
3 segment is not cathodically protected, the segment is considered “unprotected steel.”

4 Columbia also replaces short segments of pipe on an emergency bases when it is
5 determined at a leak repair jobsite that an effective repair cannot be made.

6
7 Q: Why is Columbia now so concerned with unprotected steel that it has decided to bring
8 this issue to the Commission?

9 A: Columbia has approximately 540 miles of unprotected steel and cast iron mains
10 remaining in its system along with over 15,000 bare steel service lines. This pipe has
11 been exposed to the effects of galvanic corrosion since its installation. In spite of
12 Columbia’s solid operational practices, Columbia is averaging over 1,360 corrosion leaks
13 per year over the past 5 years. In addition, over the past four years, Columbia has seen a
14 rise in the frequency of leakage. The deterioration of pipe wall at many leak sites has
15 increased significantly resulting in more frequent number of emergency replacements of
16 short sections of pipe. Because of these factors and others stated earlier, Columbia
17 believes it is in the best interest of its customers to initiate a planned and efficient
18 replacement program for the remaining inventory of bare steel and cast iron.

19
20 Q: How do you know that the cause of these leaks is corrosion?

21 A: Columbia trains its field technicians to identify corrosion conditions whenever a main or
22 service line is exposed and report these conditions on a leak report and main exposure
23 forms. While other causes can create leaks, such as third party damage (e.g. KY One-Call

1 violation), outside forces (frost, traffic loads), construction defect (damage on pipe during
2 installation), or material defect (faulty manufacturing), I have examined Columbia's leak
3 history by type, and excluding third party damage, more than 66 percent of all main leaks
4 are the result of corrosion on bare steel mains. The third party testimony submitted by
5 Edwin Humphries of Stone & Webster provides detailed analysis of Columbia's recent
6 leak history.

7
8 Q: Is replacement the only remedy? Is there any other way to retard or arrest the corrosion
9 problem inherent in unprotected steel?

10 A: In theory a cathodic protection current could be applied to the surface of a bare steel
11 piping system to protect it from galvanic corrosion. In practice, cathodic protection of
12 bare steel systems is not a practical approach. Since the amount of direct current that
13 must be applied to a bare steel surface to achieve protection is directly proportional to the
14 surface area of the steel being protected, current requirements for a bare steel system are
15 very high compared to the current requirements of a coated steel system. Introduction of
16 high levels of direct current into the soil in urban areas often results in damage to other
17 underground metal structures such as water systems, underground tanks, and metal
18 shielded cable systems, through a process called stray current corrosion. Even if cathodic
19 protection were a possibility to mitigate the ongoing deterioration caused by galvanic
20 corrosion, there is no process that could undo or replace the damage that has already
21 occurred on a bare steel system. The first generation of cast iron, wrought iron, and bare
22 steel pipe is reaching the end of its useful life and must be replaced in a timely, cost-
23 effective manner.

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Q: What method of replacement is the most cost-effective?

A: The most cost effective method of replacement is an area-based replacement strategy that will permit Columbia to bid the work competitively. The area-based replacement strategy is a program predicated on a consistent, systematic implementation that targets discrete areas, neighborhood-by-neighborhood, and block-by-block, in a geographically continuous fashion. The AMRP will be efficient because construction crews can stage work continuously by shifting the worksite along the pipe being replaced, day in and day out, rather than what is often the case now where crews open and close worksites and relocate labor and equipment across town or across the service territory. The AMRP should result in a per foot installation cost less than would be achieved by bidding smaller and more discrete tasks on a per project basis. In addition, there are the public benefits of minimizing disruptions in traffic flow by concentrating work in one section of a municipality.

Q: Where is the most pronounced corrosion problem?

A: Corrosion leakage exists in all of Columbia's system, but is particularly severe in the Lexington and Frankfort distribution systems, which have the most unprotected steel pipe per mile in any of the Columbia service territories.

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

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

5

6 Q: What public safety issues are raised?

7 A: Natural gas is an important clean energy source, but it is also a volatile commodity that is
8 unpredictable if it accumulates undetected and then comes in contact with an ignition
9 source. When it is released openly in the air, it quickly rises and dissipates safely. This
10 type of leak presents a relatively slight risk and the gas can be shut off until repairs are
11 made safely.

12 Underground leaking of natural gas can have varying consequences. Some natural
13 gas may actually migrate through the soil and escape into open air (unless soil frost or
14 water on the surface prohibits its escape), if there is a path of less resistance, such as
15 along a buried water or sewer pipeline it will follow that path. If the path allows the gas
16 to migrate into an enclosed location, such as the basement of a commercial building or
17 residence, and the natural gas accumulates there undetected, the risk increases for a
18 significant leak event where the accumulating gas may be ignited by a spark or electrical
19 charge of some kind, causing an explosion. Loss of life and property are possible in such
20 an event.

21

22 Q. How will the AMRP allow you to meet the expected requirements of a Distribution Integ-
23 rity Management Program (DIMP)?

1 A. DIMP regulation is driven by the Office of Pipeline Safety (OPS) which is scheduled to
2 release a proposed rule for Distribution Operators by April 2007. It is anticipated that
3 Distribution Operators will be required to have a written DIMP by December of 2008.
4 The rule will likely increase LDC capital investments of spend to address highest risk
5 portions of gas distribution systems. DIMP regulation will include seven (7) key ele-
6 ments:

- 7 1.) Develop and implement a written integrity management plan
- 8 2.) Know your infrastructure
- 9 3.) Identify threats, both existing and of potential future importance
- 10 4.) Assess and prioritize risks
- 11 5.) Identify and implement appropriate measures to mitigate risks
- 12 6.) Measure performance, monitor results, and evaluate the effectiveness of its
13 programs, making changes where needed
- 14 7.) Periodically report a limited set of performance measures to your regulator

15 Most of these elements will be key to establishing and maintaining a successful
16 AMRP. By implementing the AMRP now, Columbia will be addressing both the safety
17 and reliability of its infrastructure and helping fulfill the requirements of DIMP.
18

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

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

1

2 Q: Are you saying Columbia's system is unsafe?

3 A: No, the system is safe right now, as evidenced by Columbia's ability to address all
4 Grades "1", Grade "2 Priority" and Grade "2" leaks in a timely fashion. The system is
5 comprised of hundreds of miles of wrought iron, cast iron, bare steel, and unprotected
6 coated steel, with another two thousand miles of cathodically-protected steel, and plastic
7 pipe. The material initially at risk is first generation wrought iron, cast iron and bare steel.
8 This material will continue to corrode and will gradually have more leaks with increasing
9 severity. While the system is currently safe, Columbia must, as a prudent, safety-
10 conscious operator, address the systemic problem of replacing its unprotected steel and
11 cast iron facilities before the problem impacts safety and reliability. That is why
12 Columbia is implementing the AMRP now.

13

14 Q: What is the annual investment for the AMRP?

15 A: Columbia's annual investment will be approximately \$ 9.9 Million per year.

16

1 Q: Is this expected to be the continuing level of accelerated investment in the AMRP?

2 A: Yes, Columbia anticipates that the annual investment over the twenty-year program will
3 be at that level.

4
5 Q: What are the operational and field management requirements of the AMRP?

6 A: The requirements are fairly straightforward in order to drive the AMRP efficiencies. The
7 AMRP is established within a defined period of twenty years, in order to produce the
8 maximum efficiencies from the project, reduce the construction cost, minimize public
9 inconvenience and ensure public safety.

10

11 Q: How will those efficiencies and reductions in construction cost be achieved through the
12 management of the AMRP?

13 A: The AMRP will replace all unprotected steel and cast iron mains and other related
14 facilities, referred to throughout Columbia's application as Eligible Facilities, based on
15 the needs driven by the distribution system, in accordance with the basic tenets of system
16 engineering and planning. Replacements will be determined based on risk assessment; the
17 condition and age of the pipe; geographical proximity; the capacity needs of the area;
18 and, expected growth in system demand requirements. Efficiencies will be maximized
19 and costs minimized by addressing large segments of the system for replacement on a
20 planned, systematic basis. By identifying large segments of the system that require
21 attention, Columbia can focus resources and complete full segment replacements in an
22 orderly and predictable fashion.

1 Replacing pipe involves cutting of the street surface (if the main underlies a
2 street), excavating a trench a foot or so wider than the pipe to be installed, installing the
3 size and type of new pipe consistent with engineering and operations system design
4 requirements, pressure testing it, proceeding to tie-in the existing or new services and
5 mains into the new line, and finally, once the new line is tied in to all the customers, the
6 old line is abandoned, purged of remaining natural gas, and capped by welding or
7 cementing.

8

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

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

12

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

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

19

20 Q: How will the AMRP affect leak repair experience?

21 A: Columbia anticipates a significant reduction in leakage and the associated operations and
22 maintenance expenses over the duration of the proposed AMRP. As stated earlier, two
23 thirds of our leaks are due to corrosion on bare steel mains. Initially, Columbia will

1 prioritize areas and pipe segments with its worst performing pipe. This will have the
2 quickest and most beneficial impacts for Columbia's customers and its system.

3
4 Q: In planning the AMRP, were alternatively defined lengths of the program considered, and
5 why was a twenty year period selected?

6 A: Various program lengths were evaluated, but given our operational and safety objectives,
7 Columbia decided to replace the facilities in as short a timeframe as practical, i.e. twenty
8 years. Customer and municipal impacts and program implementation feasibility also were
9 taken into account in this decision. Columbia will continually monitor and evaluate the
10 program to ensure safe and reliable delivery of service.

11
12 Q: What assumptions are behind the cost estimate of \$9.9 million per year?

13 A: This dollar estimate captures all of the AMRP's Eligible Facilities, including the
14 retirement of approximately 27 miles of unprotected steel and cast iron mains each year, ,
15 as well as, the need to annually replace or reconnect an estimated 2,300 services, which
16 are connected to these mains. The program also includes costs to relocate affected meters
17 and regulators to an outside location, if necessary. Certain cost efficiencies are assumed
18 in design and construction due to advantages of project scale.

19
20 Q: What direct costs per foot or unit are you currently estimating for the Eligible Facilities?

21 A: I am estimating an average of \$53 per foot for all main installations, \$1,629 per service
22 replacement; \$200 for plastic service reconnects, \$250 in order to move any meters to an
23 outside location and \$50 to relight each of the affected customers.

1 Q: What are the benefits of the AMRP, compared with Columbia's historical steel
2 replacement program?

3 A: For municipalities and state highway departments, the AMRP provides a systematic and
4 predictable schedule of construction activities and minimizes disruption to traffic, roads
5 and highways. Greater continuity of service is also assured than if the program were
6 administered on an opportunistic basis, which is how Columbia currently addresses the
7 segments of the distribution system that require replacement due to municipal
8 improvements. As mentioned previously, by commencing an AMRP now, Columbia will
9 also be getting a head start on meeting the requirements of an anticipated DIMP.

10
11 Q: Please be specific about the community awareness benefits of the AMRP.

12 A: Under the proposed program, Columbia will be able to sectionalize the system based on
13 the worst performing areas and target replacements by neighborhood and town. During
14 the winter and early spring preceding each construction season, Columbia will meet with
15 municipal and DOT officials in the affected towns and cities from the departments of
16 public works, mayor's offices, state highway engineers, and other important contacts for
17 community outreach. It is Columbia's intent to work in concert with the municipalities to
18 achieve this end. Columbia will explain the program, discuss the planned reconstruction,
19 and work in close coordination with its Communications Department. In advance of
20 construction in each locale, Columbia will mail letters to both customers and other
21 residents along each affected street and place ads in local newspapers advising citizens of
22 the purpose for any temporary disruption and inconvenience. With a concentration of
23 resources, Columbia expects each crew to replace, on average, 250 feet of unprotected

1 steel main per day, using a geographic approach so that these crews are not forced to
2 constantly close sites and remobilize to a new location, but rather are able to concentrate
3 work in one area. This approach will result in the retirement of approximately 27 miles of
4 bare steel and cast iron mains annually for 20 years.

5
6 Q: What are the economic benefits of the AMRP?

7 A: By commencing a systematic geographic approach to replacement that integrates
8 Columbia AMRP work with state and municipal improvements, costs will be minimized.
9 A systematic replacement approach produces efficiency gains allowing more main to be
10 replaced for the same price. Columbia should also be able to work through its pipeline
11 supplier to purchase larger quantities of construction materials, resulting in lower cost.

12
13 Q: How does the customer benefit from Columbia's AMRP?

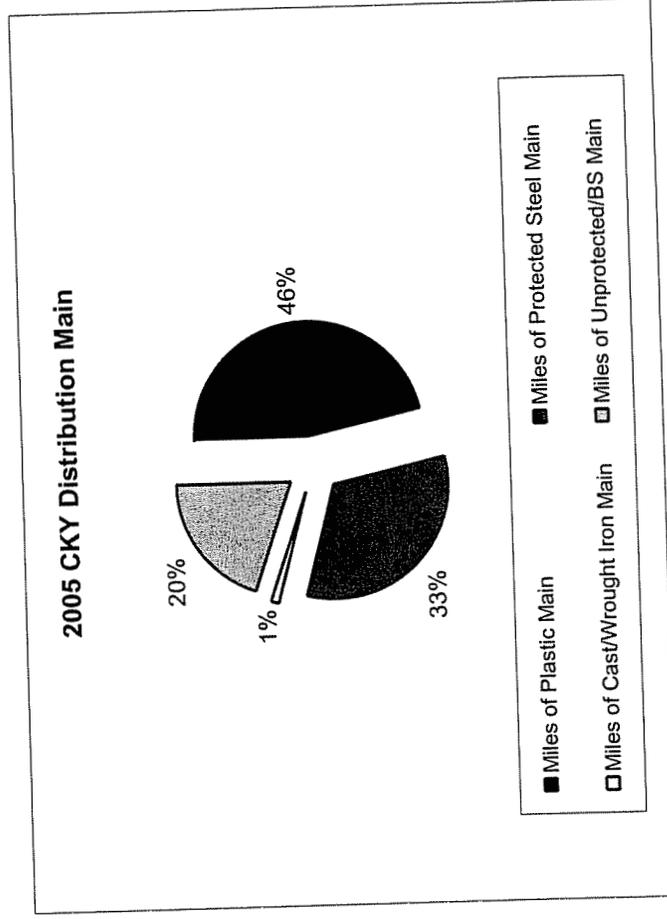
14 A: Columbia will replace deteriorating pipe and enhance the safety of its system by ensuring
15 replacement of facilities with new, longer lasting and safer materials. Its system will
16 continue to be able to provide deliverability at its Maximum Allowable Operating
17 Pressure ("MAOP"). The public will receive safe and reliable delivery of service with
18 fewer unscheduled interruptions.

19
20 Q: Does this conclude your Prepared Direct Testimony?

21 A: Subject to my reserving my right to respond to issues that may be raised in the course of
22 discovery or hearings, yes.

Exhibit #1: Breakdown of Columbia's Infrastructure

Columbia Gas of Kentucky Infrastructure Breakdown	
Miles of Plastic Main	1,207
Miles of Protected/Coated Steel Main	854
Miles of Cast/Wrought Iron Main	25
Miles of Unprotected/BS Main	516
Miles of Other Main	2
Total Miles: Distribution Main	2,604
Total Miles: Transmission Main	37
Miles in High Consequence Areas	2
District Regulator Stations	482
PODs (Town Border Stations)	119
Local Gas Producers	5
Customers (All Types)	141,277



COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia)
Gas of Kentucky, Inc.) Case No. 2007-00008

**PREPARED DIRECT TESTIMONY OF
EDWIN HUMPHRIES
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.**

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

1 **PREPARED DIRECT TESTIMONY OF EDWIN HUMPHRIES**

2 Q: Please state your name and business address for the record.

3 A: My name is Edwin Humphries. My business address is One Main Street, Cambridge,
4 MA.

5
6 Q: For whom do you work and in what capacity?

7 A: I work for Stone & Webster Management Consultants, Inc, ("Stone & Webster
8 Consultants") as an Executive Consultant.

9
10 Q: Please describe Stone & Webster Consultants.

11 A: Stone & Webster Consultants, a Shaw Group Company, is an international consulting
12 firm in the power, process, infrastructure and government sectors. We serve power, gas
13 and water utility companies; oil and gas exploration, production and pipeline firms;
14 petroleum refineries, terminals and transportation firms; petrochemical and inorganic
15 chemical companies; investment and commercial banks; multilateral institutions;
16 regulatory agencies; and governments worldwide. Stone & Webster Consultants is a
17 subsidiary to Stone & Webster, Inc. ("Stone & Webster"), a Shaw Group Company that
18 specializes in engineering and construction. Originally founded in 1889 as an electrical
19 testing laboratory and consulting firm, Stone & Webster grew into a network of
20 companies employing over 6,000 people worldwide. Stone & Webster provides
21 planning, engineering, design, procurement, construction, operations and maintenance
22 services to power, process, government, and industrial clients.

23 Q: Please describe your work and educational experience.

24 A: I graduated from London University with an honors degree in Mechanical Engineering in
25 1965. In 1970 I immigrated to Montreal, Canada due to my job with Rolls Royce.
26 During 1975 I moved to Calgary where I worked on the Arctic Gas and Foothills
27 Pipelines. During this time I completed parts one and two of the Natural Gas Processing
28 Principles and Technology at Calgary University. During 1983 I joined Stone & Webster
29 Engineering Corporation and was transferred to Boston where I helped to establish the
30 Pipeline Services Group. During 2004 I transferred to Stone & Webster Consultants. For
31 the past thirty years I have been engaged almost exclusively in natural gas pipeline and
32 storage assignments.

33

34 Q: Please describe your membership in, or affiliations with any industry organizations.

35 A: I have been a member of the American Society of Mechanical Engineers ("ASME") for
36 the past 27 years. During 1986-1988, I served as Chairman of the Pipelines and
37 Applications Committee of the Gas Turbine Institute. I have also been admitted to the
38 following organizations:

- 39 1. Member, Institution of Mechanical Engineers, 1972
 - 40 2. Chartered Engineer, 1974
 - 41 3. Association of Professional Engineers of Alberta, 1976
 - 42 4. Association of Professional Engineers of Massachusetts, 1993
- 43
44
45

46 Q: What is the purpose of today's testimony?

47 A: The purpose of my testimony is to support the independent review of Columbia Gas of
48 Kentucky's ("Columbia") cast iron and bare steel replacement program.

49

50 Q: Describe Columbia's current distribution infrastructure.

51 A: The Columbia records go back over 100 years. The build up of Columbia's distribution
52 infrastructure is depicted on Figure 1, Columbia's Current Distribution Infrastructure.

53 This figure shows the evolution of the gas mains installation. Columbia's current
54 distribution system consists of treated steel, plastic, bare steel and cast iron.

55

56 Q: How can you be sure that the results of your study are accurate and that the
57 recommendations provided are soundly based?

58 A: Columbia keeps detailed records of the operation of their system. This includes records
59 of every section of gas main that has been inspected, replaced and repaired over many
60 years. These records have been provided to Stone & Webster Consultants for analysis.

61 The results of the analysis have been plotted on curves that characterize Columbia mains
62 leakage over the past eight years. The Columbia curves have also been plotted against
63 similar curves for different gas companies, such that a meaningful comparison can be
64 made. In the cases of the other companies', the data was obtained from the Department
65 of Transportation database for the same eight year period.

56 Q: What does the analysis of the Columbia data show?

67 A: In analyzing the data Stone & Webster Consultants has grouped the bare steel mains and
68 coated mains but not cathodically protected mains together and segregated them from the
69 cast iron mains. The reasoning here is to demonstrate that although cast iron is not as
70 prone to corrosion compared to bare steel it does have other weaknesses that need to be
71 addressed. The results of the analysis are presented in Figure 2, which sorts the leak data
72 from the past 15 years into causes associated with piping material types. The primary
73 findings confirm the statements made in Mr. Webb's testimony. Stone & Webster
74 Consultants can confirm that the statement, "excluding third party damage, 66% of all
75 leaks is the result of corrosion on bare steel mains" is correct based on the data analyzed.
76 See Figure 3. Over the past 15 years a total of 6,018 corrosion leaks have been repaired.
77 It should be noted that although Columbia installed coated piping, without cathodic
78 protection in the 1950s and 1960s as a preferred alternative to bare steel, the effects of
79 time have demonstrated that in many respects the coating does not offer any tangible
80 benefits against the attack of corrosion. So, although approximately 10% of the
81 unprotected steel pipe is coated, functionally it is regarded as bare steel. The effects of
82 leakage due to corrosion were plotted on Figure 4. Also plotted are the annual repair
83 rates for other leaks divided by miles of protected piping and the total leaks divided by
84 the total piping. The curve of the effects of corrosion on bare steel mains compared to
85 the effects of other causes on other types of mains are clearly shown.

86 The leakage occurring in cast iron pipe is also shown in Figure 2. In this case the
87 number of instances of cast iron corrosion is considerably less than that of bare steel but
88 other characteristics makes cast iron more vulnerable to leaks than other forms of pipe.

89 In total 246 leaks were repaired, 35 due to corrosion, 211 due to other causes, for an
90 annual average of 0.606 leaks per mile per year. The annual incidents of corrosion
91 leakage for bare steel and for all causes on cast iron are plotted in Figure 5. The curves
92 are based on the actual number of miles of bare steel and cast iron main. Also shown on
93 Figure 5 is the curve of the leakage rates of plastic and cathodically protected coated
94 steel. This demonstrates that the leakage rates are approximately six times higher in the
95 cases of bare steel and cast iron compared to coated protected steel and plastic.

96

97 Q: How does the number of corrosion leaks occur in general in the gas industry?

98 A: The best definitive data available is contained in the report “Integrity Management for
99 Gas Distribution” issued December, 2005 as depicted in Figure 6. This was prepared by
00 joint work/study groups including representation of:

- 101 1. Stakeholder Public
- 102
- 103 2. Gas Distribution Pipeline Industry
- 104
- 105 3. State Pipeline Safety Representatives
- 106
- 107 4. Pipeline and Hazardous Materials Safety Administration
- 108

109 This report states that the national average of leaks removed for cause, are as follows:

Corrosion	36%
Natural Forces	8%
Excavation	16%
Other Outside Forces	2%
Materials or Welds	8%
Equipment	4%

Operations	1%
Other ¹	26%

110

111 ¹Other is used when it can not be determined what contributed to the failure. It
112 appears that incidents in this category involve customer piping or appliances that are not
113 operated and maintained by the gas distribution company.

114 On this basis it can be seen that the corrosion leaks experienced by Columbia are
115 considerably higher than the national average.

116

117 Q: How do the corrosion leakage rates vary from location to location?

118 A: The analysis considered the six service territories of Lexington, Frankfort, Winchester,
119 Ashland, Maysville and Lancer. The results are given in Figure 7. Historically in the
120 locations of Lexington and Frankfort the leakage due to corrosion reached peak values of
121 77% and 78% of the total respectively. In 1993 and 1996 Lancer, a small community
122 reached 93%.

123

124 Q: What other companies were used for comparison and why were they chosen?

125 A: Comparative Companies are:

- 126 1. Cincinnati Gas & Electric - OH
- 127 2. Union Light Heat & Power - KY
- 128 3. Peoples Gas/Aquila - NE
- 129 4. Montana Power/Northwestern Energy - MT
- 130 5. Northwestern Energy - NE & SD
- 131 6. Montana-Dakota - ND
- 132 7. Vectren (Vedi-North) - IN

133

34 All of these companies have been studied by Stone & Webster Consultants in
135 previous Gas Distribution Company Projects. They represent a balanced cross section of
136 companies from which a comparison can be made. Cincinnati Gas & Electric, Union
137 Light Heat & Power and Vectren are companies that also serve geographical areas in
138 relatively close proximity to the Columbia territory. Starting in the early 2000s these
139 three companies have engaged in a fairly aggressive campaign to purge out their bare
140 steel and cast iron mains. The other four systems are all located some distance from
141 Kentucky but are considered to be good benchmarks.

142

143 Q: How do these other Distribution Companies compare to Columbia with respect to
144 corrosion?

45 A: The pipeline parameters for all pipelines are given in Figure 8. This shows the history of
146 each gas distribution company from 1998 through the end of 2005 including the leakage
147 due to corrosion for Columbia, Peoples Gas, Union Light Heat & Power, Cincinnati Gas
148 & Electric and Vectren. The difference between Columbia and the other four gas
149 companies is very pronounced. Leaks due to corrosion are two to three times higher in
150 the case of Columbia. Since Columbia does not have an accelerated main replacement
151 program the rate of bare steel and cast iron replacement on a relative basis is lower than
152 the other gas distribution companies that have recently implemented an accelerated main
153 replacement program. Without an accelerated main replacement program it will take
154 Columbia twice as long as Peoples Gas and three times as long as Cincinnati Gas &
155 Electric to completely remove all the bare steel mains at the current rate of removal.
56 Peoples Gas, Union Light Heat & Power, Cincinnati Gas & Electric and Vectren have

57 implemented an accelerated main replacement program. The following table summarizes
158 the current removal rate of representative gas distribution companies:

Gas Company	Current Removal Rate	Time to Completely Remove
Peoples Gas	7.75 miles/year	27.5 years to totally remove
Union Light, Heat & Power	17.25 miles/year	5-6 years to totally remove
Cincinnati Gas & Electric	7.75 miles/year	19.0 years to totally remove
Vectren	91.4 miles/year	12.0 years to totally remove
Columbia	9.0 miles/year	60.0 years to totally remove

159
160 As pipelines age the relentless attack by corrosive forces on unprotected bare steel
161 continues unabated. There is no point at which corrosion stops, or slows down. Given
162 enough time the bare steel mains will turn completely to rust. The examples given above
163 show how other gas distribution companies are dealing with the problem. Vectren has
164 just implemented a very aggressive schedule which will average over 91 miles of main
165 replacement per year. If this rate is sustained they will clear their system in
166 approximately 12 years. Cinergy the parent of Union Gas formulated a ten year plan in
167 2000. They are progressing close to their plan and will have its system free of bare steel
168 and cast iron in another five to six years. The rate of corrosion repairs has declined from
169 0.40 repairs per mile down to 0.25 repairs per mile over the past seven years. Cincinnati
170 Gas is working to a 19-20 year schedule. This is a very manageable schedule and is

71 recommended for Columbia. This would require a tripling of the present rate of piping
172 replaced to 27 miles per year as shown in the table below.

Gas Company	Proposed Removal Rate	Time to Completely Remove
Columbia	27.0 miles/year	20.0 years to totally remove

173

174 Q. How does the non corrosion rate of repair compare?

175 A: The repair rates for non corrosion related leaks are compared in Figure 9. Columbia's
176 leak repair rate has been declining steadily since 1999 from 0.10 leaks/mile to 0.065
177 leaks/mile in 2005. This is well above the four comparative companies from Western
178 States, but appears to be converging with them. Both Union Gas and Cincinnati Gas
179 have undergone some gyrations but are also now appearing to converge on a value of
180 0.10-0.12 leaks/mile.

181

182 Q: What are Stone & Webster Consultants' recommendations?

183 A: Many utilities nationwide and internationally are recognizing the need for the
184 replacement of ageing unprotected metallic system mains. A recent study prepared for
185 the American Gas Foundation titled "Safety Performance and Integrity of the Natural Gas
186 Distribution Infrastructure" found that of the distribution companies surveyed, 65% have
187 a planned replacement program for their cast iron mains and 74% have a planned
188 replacement program for their bare steel mains system. The operators of these companies
189 have identified higher risk segments of their distribution infrastructure in their bare steel
190 and cast iron mains and are taking prevention and mitigation measures to insure the
191 safety and integrity of their systems. Columbia's distribution system has approximately
192 540 miles of unprotected bare steel and cast iron mains remaining in its system along

93 with over 15,000 bare steel service lines. Given the fact that 66% of all leaks are a result
194 of corrosion on bare steel mains Stone & Webster Consultants recommends that an
195 accelerated mains replacement program be established to replace all bare steel and cast
196 iron mains.

197

198 Q: Does this conclude your Prepared Direct Testimony?

199 A: Yes.

Figures

Figure 1 – Columbia's Current Distribution Infrastructure
Miles Installed by Year

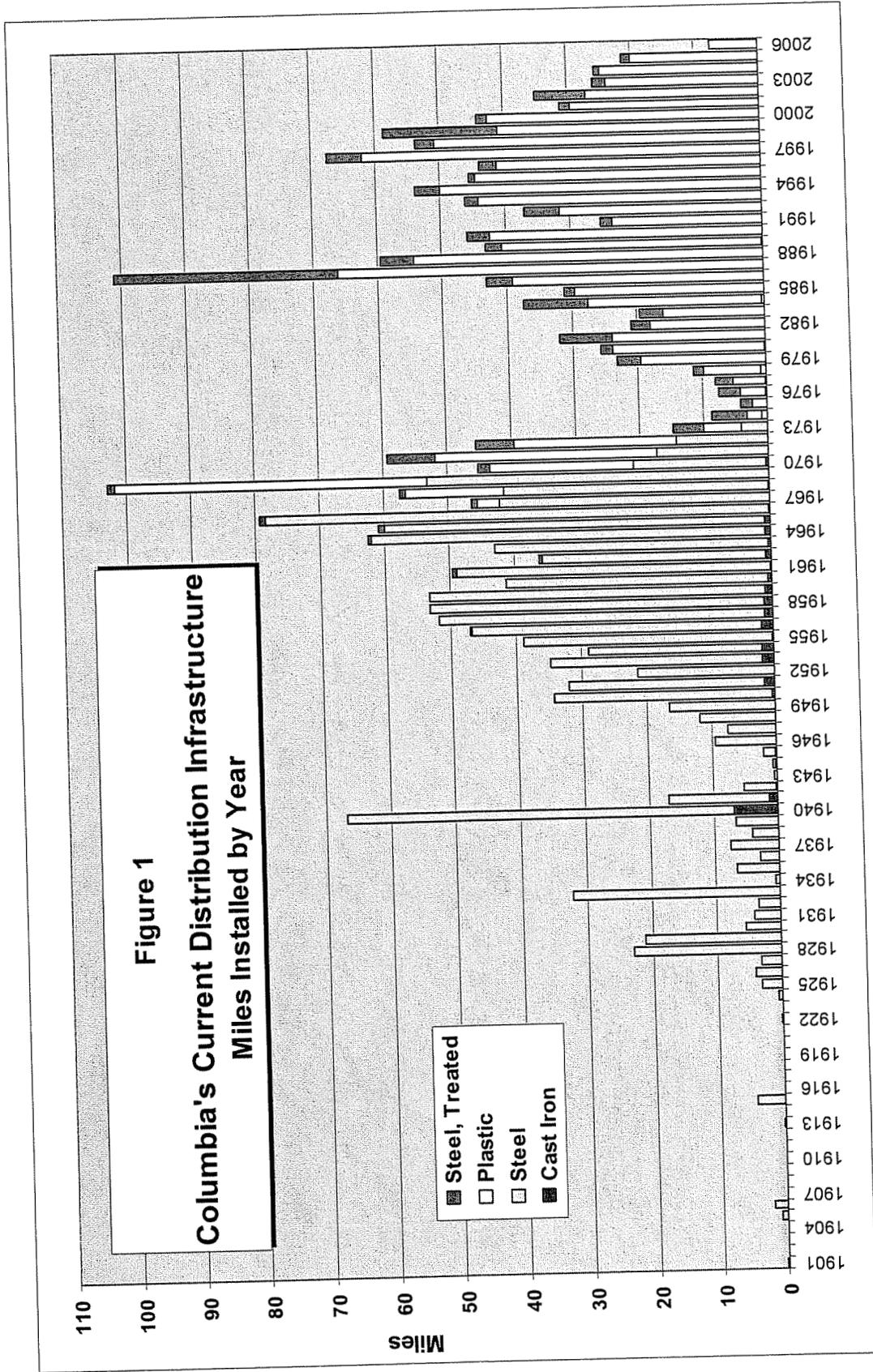


Figure 2 – Gas Main Leaks by Material & Causes

Columbia

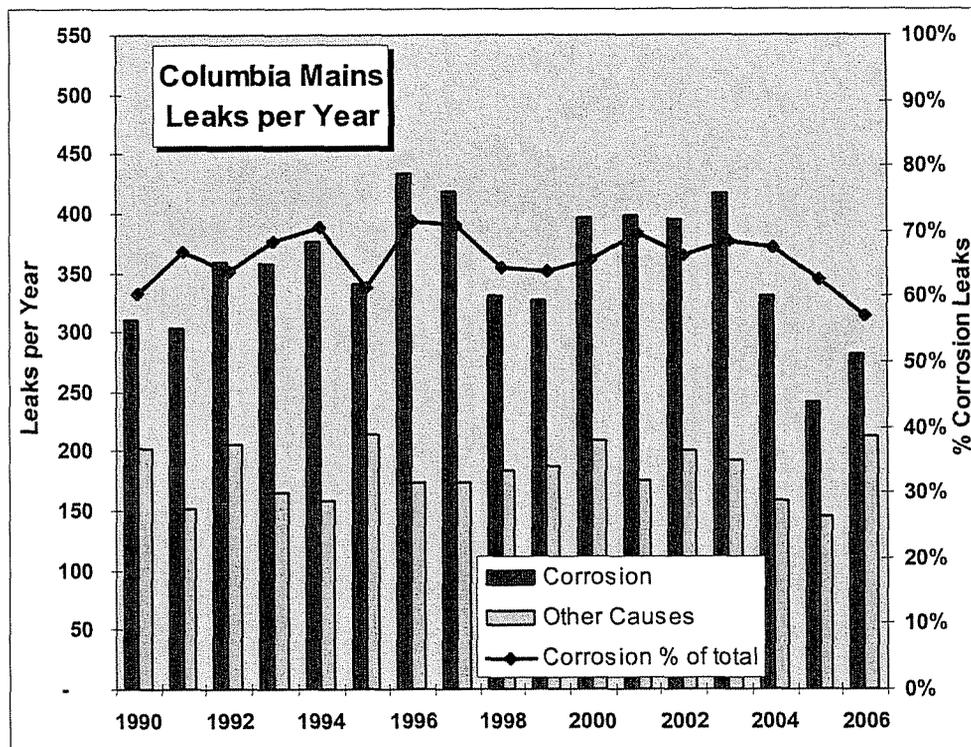
Year	Corrosion				Other Causes						Total Other Causes	Total Lea	
	Cast Iron	Treated Steel	Bare Steel	Unknown	Total Corrosion	Cast Iron	Other	Plastic	Treated Steel	Bare Steel			Unknown
1990	1		309		310	3		55		88	107	253	56
1991	1		302		303	10	1	74		64	71	220	52
1992	2	1	356	1	360	14	1	87	1	79	102	284	64
1993	2	10	345		357	12		100	7	66	58	243	60
1994	3	4	369		376	8		111	2	77	38	236	61
1995	1	3	336		340	13		124	10	132	24	303	64
1996	5	9	420		434	8	8	122	4	106	23	271	70
1997	5	13	400	1	419	16	2	147	6	111	9	291	71
1998	1	9	320	1	331	14		129	6	104	14	267	59
1999	1	10	317		328	11	2	147	8	120	16	304	63
2000	2	5	390		397	24	2	149	12	111	11	309	70
2001	1	5	398		399	15	1	123	1	109	14	263	66
2002	3	8	383	1	395	16		132	3	117	22	290	68
2003	2	20	393	1	416	16	1	144	10	88	18	277	69
2004	1	18	311		330	12		131	16	77	2	238	56
2005	2	18	221		241	4	2	102	21	63	32	224	46
2006	2	14	265	1	282	15		90	27	53	91	276	55
Total	35	142	5,835	6	6,018	211	20	1,967	134	1,565	652	4,549	10,5

Figure 2 – Continued

Year	Bare Steel		Cast Iron			Total Other Pipe	Total Leaks
	Other Causes	Corrosion	Total Bare Steel	Other Causes	Corrosion		
1990	2	309	311	3	1	4	563
1991	3	302	305	10	1	11	523
1992	11	358	369	14	2	16	644
1993	34	355	389	12	2	14	600
1994	35	373	408	8	3	11	612
1995	36	339	375	13	1	14	643
1996	40	429	469	8	5	13	705
1997	52	414	466	16	5	21	710
1998	32	330	362	14	1	15	598
1999	49	327	376	11	1	12	632
2000	43	395	438	24	2	26	706
2001	48	398	446	15	1	16	662
2002	44	392	436	16	3	19	685
2003	40	414	454	16	2	18	693
2004	32	329	361	12	1	13	568
2005	21	239	260	4	2	6	465
2006	27	280	307	15	2	17	558
Total	549	5,982	6,532	211	35	246	10,567

Figure 3 – Gas Main Leaks/Year
Columbia
Excluding Third Party

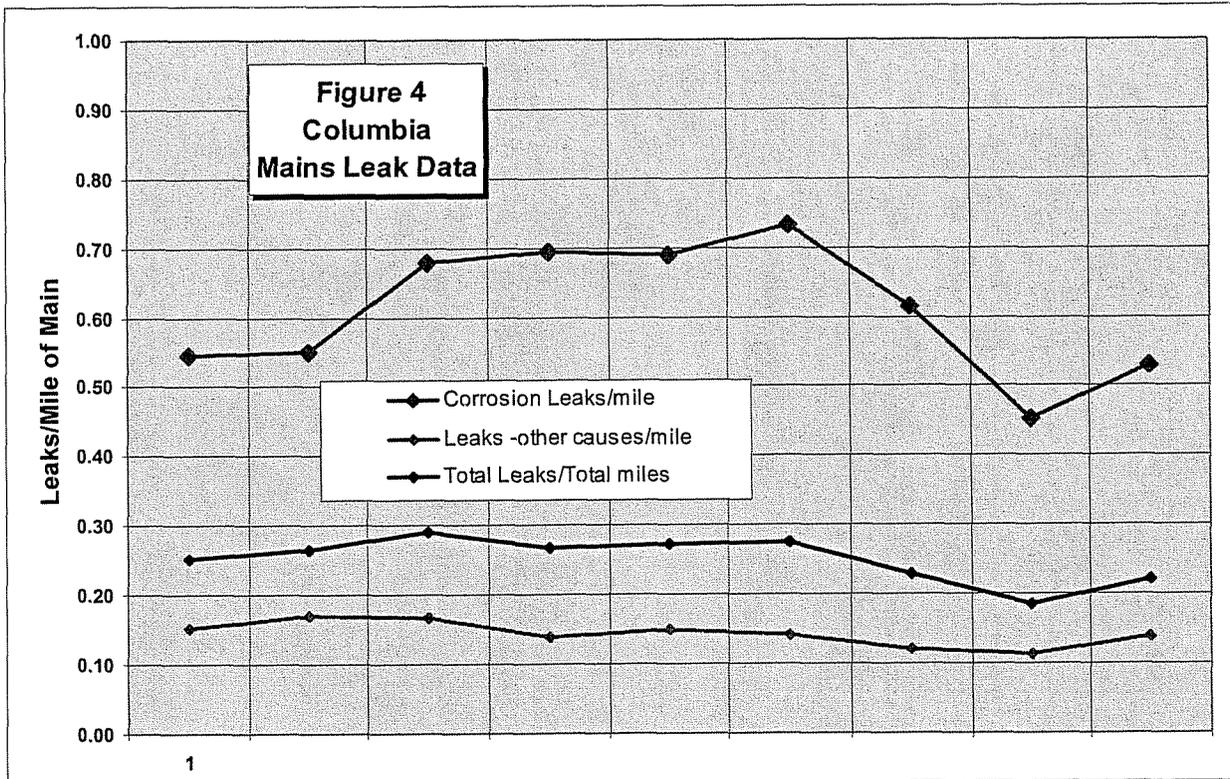
<u>Year</u>	<u>3rd Party</u>	<u>Other Causes</u>	<u>Corrosion</u>	<u>Total</u>	<u>Total excl 3rd Party</u>	<u>Corrosion % of total</u>
1990	50	203	310	563	513	60%
1991	69	151	303	523	454	67%
1992	79	205	360	644	565	64%
1993	78	165	357	600	522	68%
1994	78	158	376	612	534	70%
1995	88	215	340	643	555	61%
1996	98	173	434	705	607	71%
1997	118	173	419	710	592	71%
1998	83	184	331	598	515	64%
1999	117	187	328	632	515	64%
2000	100	209	397	706	606	66%
2001	88	175	399	662	574	70%
2002	89	201	395	685	596	66%
2003	84	193	416	693	609	68%
2004	80	158	330	568	488	68%
2005	79	145	241	465	386	62%
2006	<u>63</u>	<u>213</u>	<u>282</u>	<u>558</u>	<u>495</u>	<u>57%</u>
	1,441	3,108	6,018	10,567	9,126	66%



Proprietary & Confidential

Figure 4 – Columbia Mains Leak Data

Columbia									
	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>
<u>Miles of unprotected mains</u>									
Bare Steel	507	503	477	490	488	542	513	509	509
Coated steel (BS)	71	66	80	58	59	-	-	-	-
Cast Iron	<u>28</u>	<u>28</u>	<u>27</u>	<u>27</u>	<u>26</u>	<u>26</u>	<u>24</u>	<u>24</u>	<u>24</u>
Total miles of unprotected mains	606	597	584	575	573	568	537	533	533
Total miles of unprotected mains	<u>1,760</u>	<u>1,799</u>	<u>1,843</u>	<u>1,896</u>	<u>1,933</u>	<u>1,957</u>	<u>1,956</u>	<u>1,984</u>	<u>1,984</u>
Total miles of mains	2,366	2,396	2,427	2,471	2,506	2,525	2,493	2,517	2,517
Leaks -Corrosion	331	328	397	399	395	416	330	241	282
Leaks -other causes	<u>267</u>	<u>304</u>	<u>309</u>	<u>263</u>	<u>290</u>	<u>277</u>	<u>238</u>	<u>224</u>	<u>275</u>
Total Leaks	598	632	706	662	685	693	568	465	557
Corrosion Leaks/mile	0.546	0.549	0.680	0.694	0.689	0.732	0.615	0.452	0.529
Leaks -other causes/mile	0.152	0.169	0.168	0.139	0.150	0.142	0.122	0.113	0.139
Total Leaks/Total miles	0.253	0.264	0.291	0.268	0.273	0.274	0.228	0.185	0.221



**Figure 5 – Gas Main Leaks – Bare Steel & Cast Iron
 Columbia**

	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>
<u>Cast Iron</u>									
Leaks -other causes	14	11	24	15	16	16	12	4	15
Leaks -Corrosion	<u>1</u>	<u>1</u>	<u>2</u>	<u>1</u>	<u>3</u>	<u>2</u>	<u>1</u>	<u>2</u>	<u>2</u>
CI - All Leaks	15	12	26	16	19	18	13	6	17
CI - Miles	28	28	27	27	26	26	24	24	24
CI - All Leaks/Mile	0.536	0.429	0.963	0.593	0.731	0.692	0.542	0.250	0.708
<u>Bare Steel</u>									
Leaks -other causes	32	49	43	48	44	40	32	21	27
Leaks -Corrosion	<u>330</u>	<u>327</u>	<u>395</u>	<u>398</u>	<u>392</u>	<u>414</u>	<u>329</u>	<u>239</u>	<u>280</u>
BS - All Leaks	362	376	438	446	436	454	361	260	307
BS - Miles	578	569	557	548	547	542	513	509	509
BS - All Leaks/Mile	0.626	0.661	0.786	0.814	0.797	0.838	0.704	0.511	0.603
<u>All Other Pipe</u>									
Other Pipe - All Leaks	221	244	242	200	230	221	194	199	233
Other Pipe - Miles	1,760	1,799	1,843	1,896	1,933	1,957	1,956	1,984	1,984
Other Pipe - All Leaks/Mile	0.126	0.136	0.131	0.105	0.119	0.113	0.099	0.100	0.117
<u>Bare Steel & Cast Iron</u>									
BS & CI - All Leaks	377	388	464	462	455	472	374	266	324
BS & CI - Miles	606	597	584	575	573	568	537	533	533
BS & CI - All Leaks/Mile	0.622	0.650	0.795	0.803	0.794	0.831	0.696	0.499	0.608

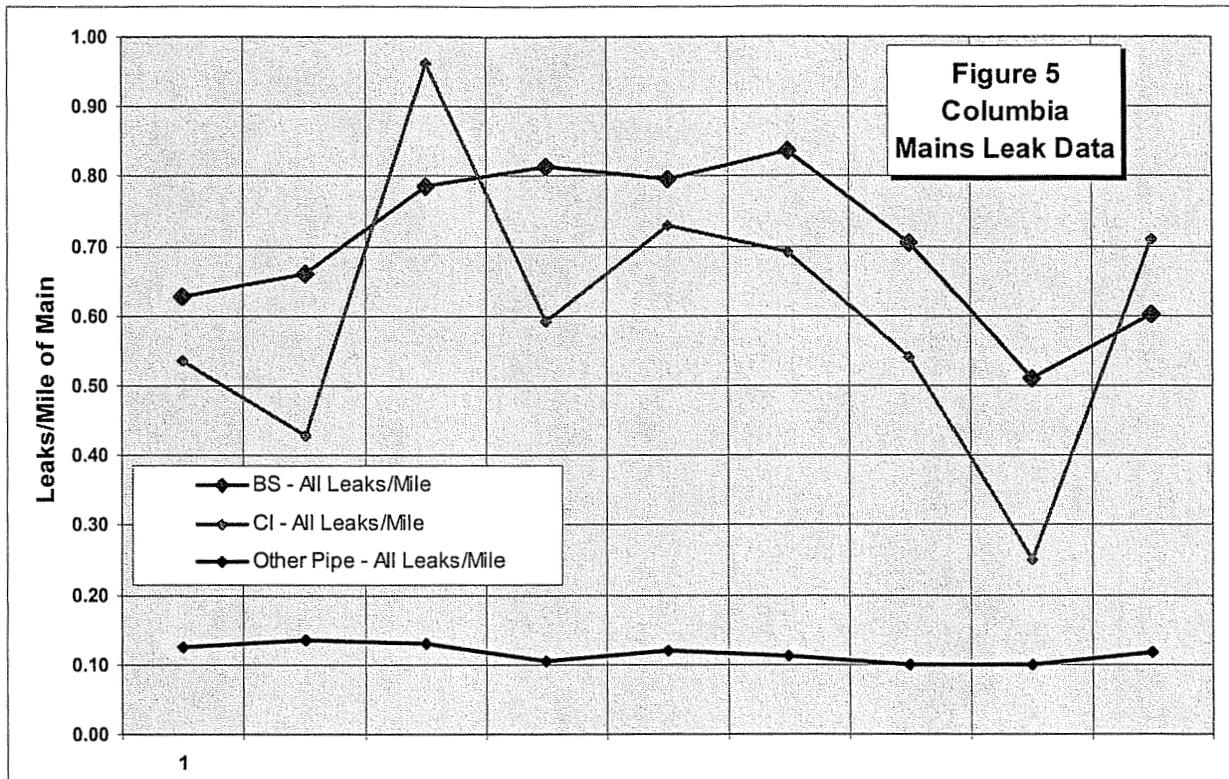
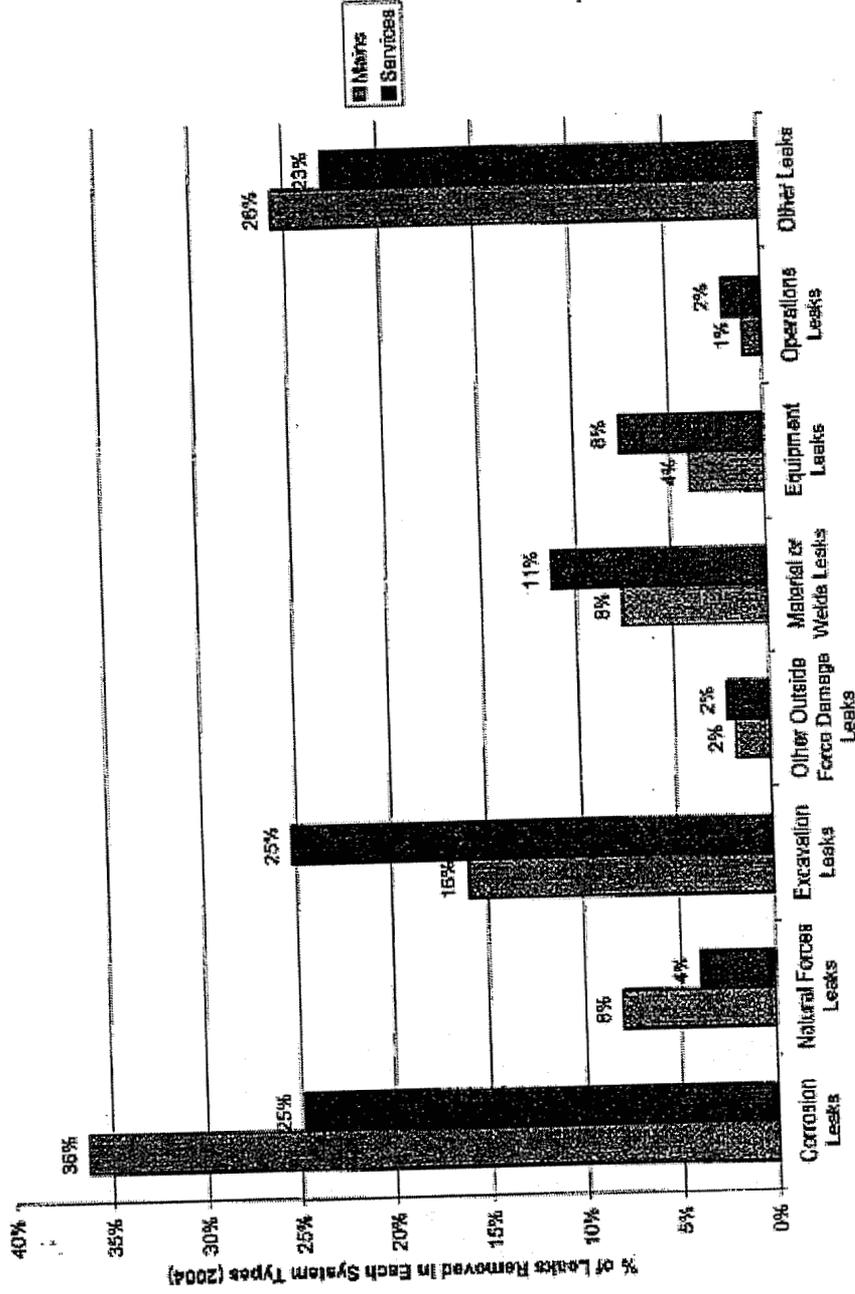


Figure 6 – 2004 Leaks Removed by Causes and System Types



2004 Annual data reported as of 09/15/2005.

Figure 7 – Gas Main Leaks by Service Territories

Columbia

Location	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Grand Total
Corrosion Leaks	123	116	135	159	143	108	189	154	112	131	161	152	158	180	170	115	126	2,432
2621 LEXINGTON																		986
2623 FRANKFORT	53	63	54	41	35	44	61	74	43	26	76	91	104	75	51	47	48	942
2629 WINCHESTER	64	49	63	43	75	63	50	56	60	69	68	59	63	62	42	31	25	1,345
2631 ASHLAND	51	59	83	98	94	104	110	118	101	83	80	73	50	85	53	36	67	99
2632 MAYSVILLE	8	5	13	3	3	4	10	12	10	6	5	3	6	3	4	1	3	214
2633 LANCER	11	11	12	13	26	17	14	5	5	13	7	21	14	11	10	11	13	6,018
Total Corrosion Leaks	310	303	360	357	376	340	434	419	331	328	397	399	395	416	330	241	282	
All Leaks	207	171	242	241	186	174	249	206	182	189	221	198	233	250	227	165	207	3,548
2621 LEXINGTON																		1,452
2623 FRANKFORT	72	82	73	53	57	74	79	95	67	51	126	130	153	113	78	73	75	1,515
2629 WINCHESTER	127	74	92	77	127	108	82	89	95	103	109	86	99	89	58	52	48	2,087
2631 ASHLAND	82	98	119	129	127	160	161	175	146	140	116	129	80	133	92	70	130	220
2632 MAYSVILLE	13	16	26	8	8	18	21	19	17	8	20	5	10	5	11	4	11	304
2633 LANCER	12	13	13	14	29	21	15	8	8	24	14	26	21	19	22	22	23	494
Total All Leaks	513	454	565	522	534	555	607	592	515	515	606	574	596	609	488	386	494	9,126
Corrosion Leaks	59%	68%	56%	66%	77%	62%	76%	75%	62%	69%	73%	77%	68%	72%	75%	70%	61%	69%
2621 LEXINGTON																		68%
2623 FRANKFORT	74%	77%	74%	77%	61%	59%	77%	78%	78%	51%	60%	70%	68%	66%	65%	64%	64%	62%
2629 WINCHESTER	50%	66%	68%	56%	59%	58%	61%	63%	63%	67%	62%	69%	69%	70%	72%	60%	52%	64%
2631 ASHLAND	62%	60%	70%	76%	74%	65%	68%	67%	69%	59%	69%	57%	63%	64%	58%	51%	52%	45%
2632 MAYSVILLE	62%	31%	50%	38%	38%	22%	48%	63%	59%	75%	25%	60%	60%	60%	45%	50%	57%	70%
2633 LANCER	92%	85%	92%	93%	90%	81%	93%	63%	63%	54%	50%	81%	67%	58%	68%	62%	57%	66%
Total Corrosion Leaks	60%	67%	64%	68%	70%	61%	71%	71%	64%	64%	66%	70%	66%	68%	68%	68%	62%	57%

Location	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Grand Total	
Corrosion Leaks/Mile																			
2621 LEXINGTON											0.71	0.67	0.71	0.72	0.67	0.46	0.50	0.63	
2623 FRANKFORT											1.31	1.60	1.77	1.23	0.83	0.78	0.79	1.19	
2629 WINCHESTER											0.87	0.77	0.86	0.86	0.58	0.66	0.53	0.73	
2631 ASHLAND											0.64	0.60	0.42	0.66	0.44	0.30	0.55	0.52	
2632 MAYSVILLE											0.59	0.35	0.70	0.18	0.25	0.06	0.18	0.33	
2633 LANCER											0.43	1.35	0.97	0.78	0.72	0.82	0.97	0.86	
Total											0.77	0.79	0.79	0.77	0.61	0.47	0.55	0.68	

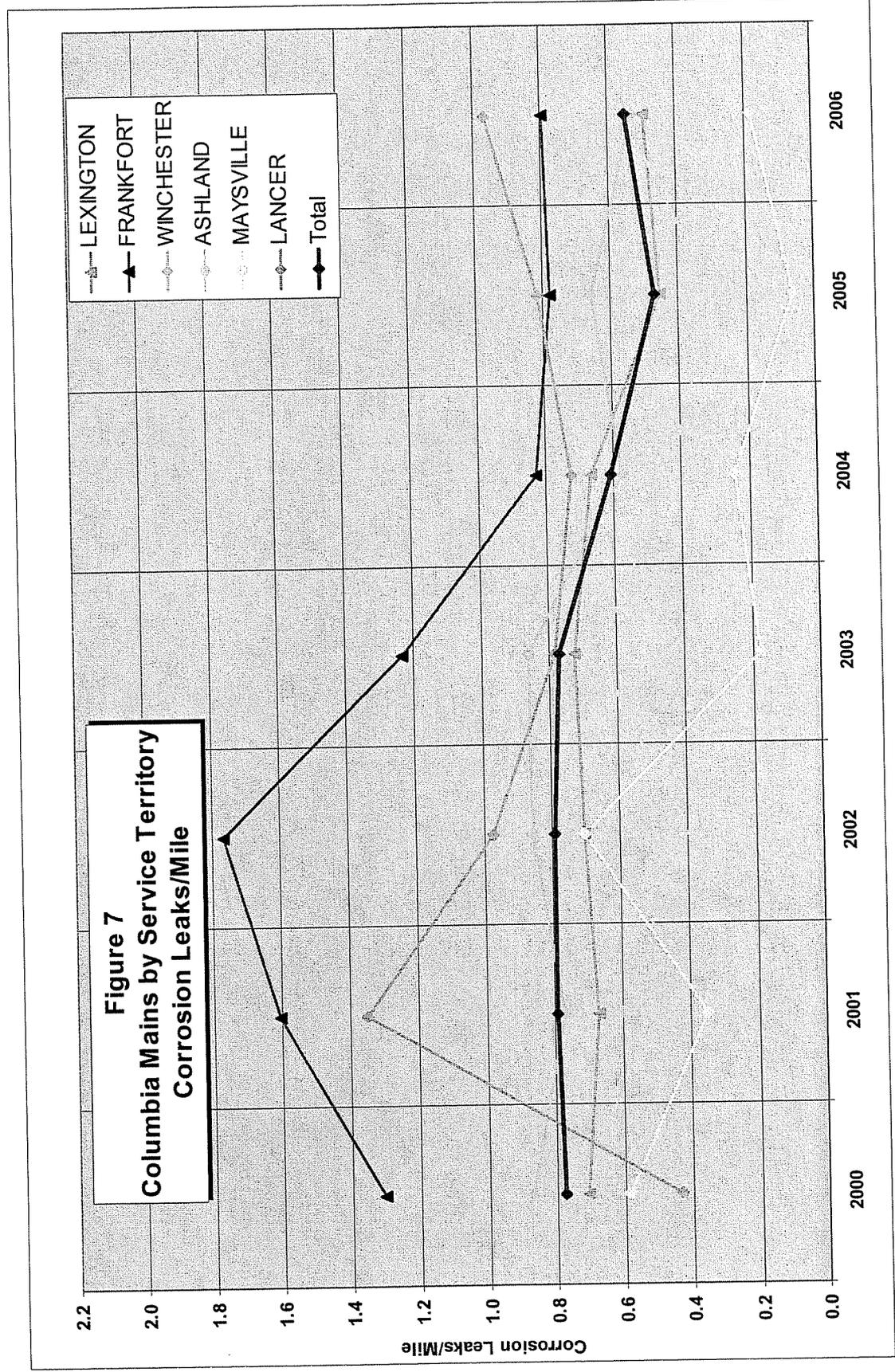


Figure 8 – Gas Main Leaks/Unprotected Mile Comparison to Other Utilities
Columbia

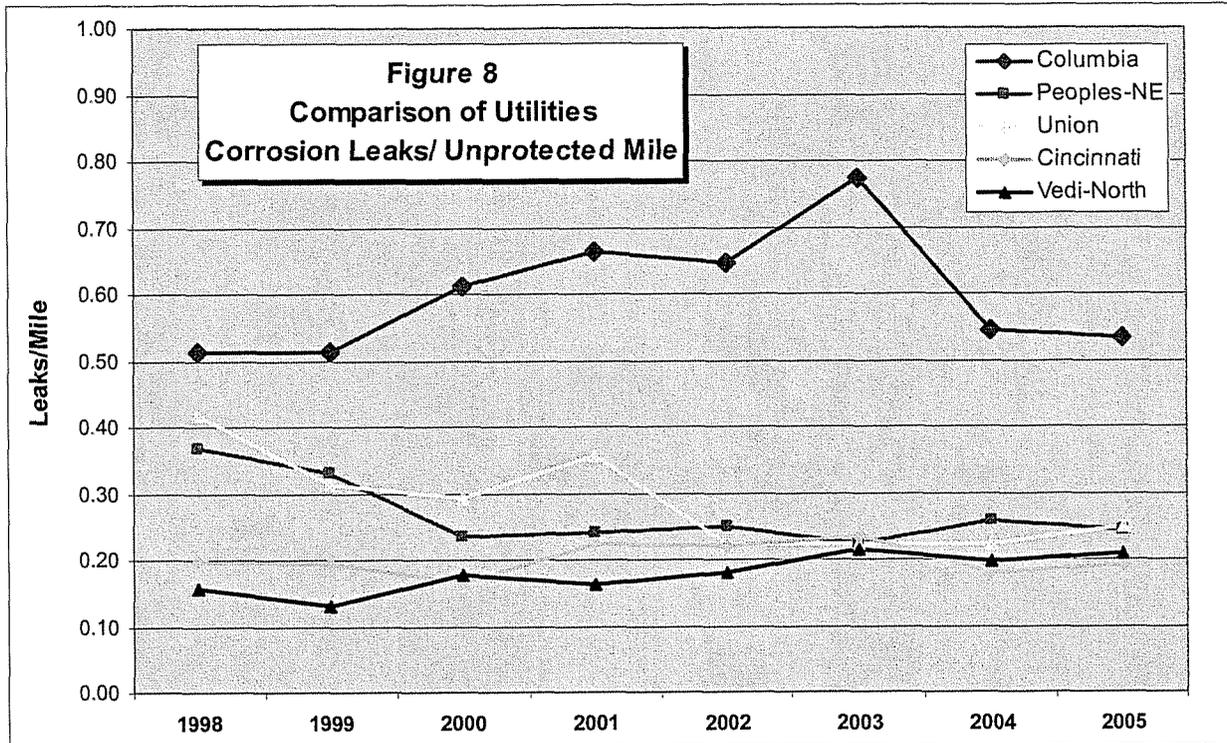
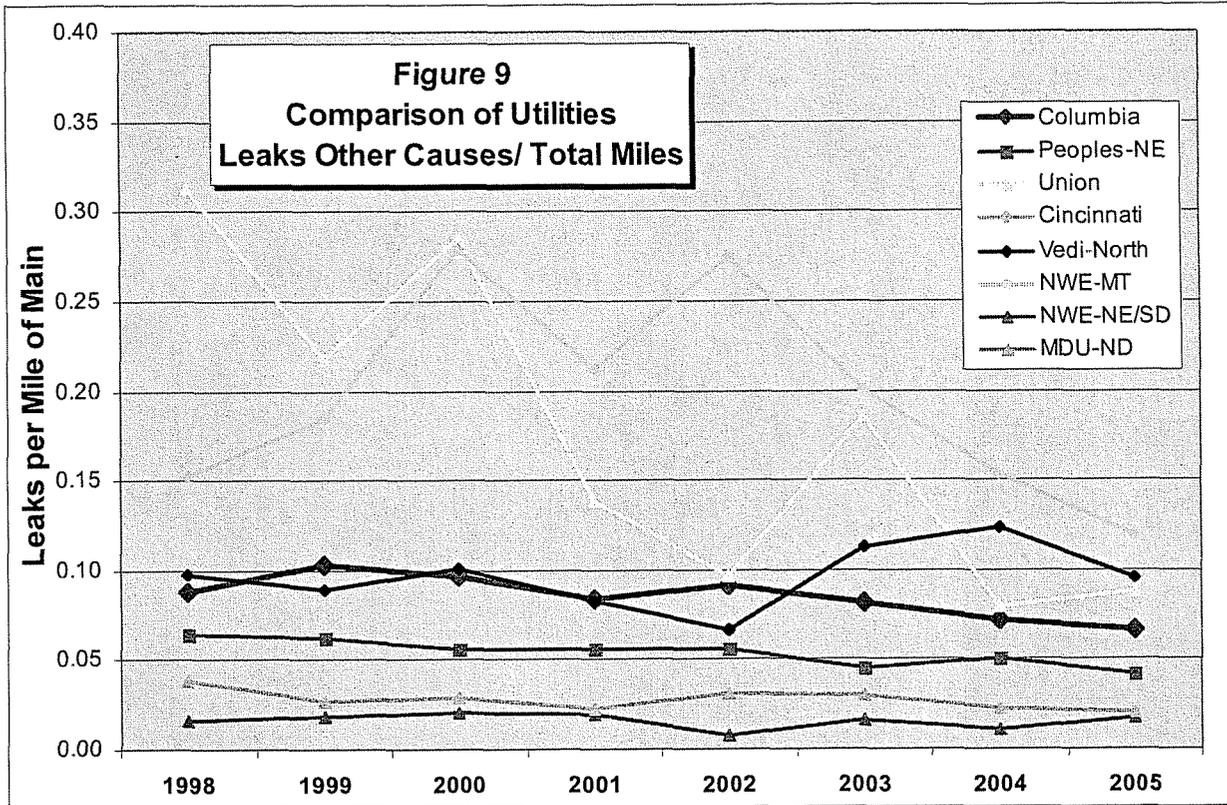


Figure 9 – Gas Mains Leaks/Mile Comparison to Other Utilities
 Columbia



Leaks Other Causes / Total Miles

Year	NWE-MT	NWE-NE/SD	MDU-ND	Peoples-NE	Union	Columbia	Cincinnati	Vedi-North
1998	0.030	0.016	0.039	0.064	0.313	0.088	0.152	0.098
1999	0.025	0.018	0.027	0.062	0.218	0.103	0.184	0.089
2000	0.033	0.020	0.029	0.056	0.285	0.096	0.279	0.100
2001	0.028	0.019	0.022	0.056	0.138	0.084	0.212	0.082
2002	0.036	0.008	0.031	0.056	0.096	0.091	0.274	0.066
2003	0.036	0.016	0.030	0.045	0.186	0.081	0.201	0.112
2004	0.028	0.011	0.022	0.050	0.079	0.072	0.153	0.123
2005	0.029	0.017	0.020	0.042	0.088	0.066	0.119	0.096

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia)
Gas of Kentucky, Inc.) Case No. 2007-00008

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

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February 1, 2007

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

PREPARED DIRECT TESTIMONY OF JUDY M. COOPER

1 Q: Please state your name and business address.

2 A: Judy M. Cooper. 2001 Mercer Road, Lexington, KY 40512.

3

4 Q: By whom are you employed?

5 A: I am employed by Columbia Gas of Kentucky, Inc. (“Columbia”).

6

7 Q: What is your current position with Columbia?

8 A: I am the Director of Regulatory Policy.

9

10 Q: What is your educational background?

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

14

15 Q: Please describe your employment history.

16 A: I was employed by the Kentucky Public Service Commission (“Commission”) as an audi-
17 tor in 1982. Subsequently, I was employed as a rate analyst, Energy Policy Advisor,
18 Branch Manager of Electric and Gas Rate Design, and Director of Rates, Tariffs and Fi-
19 nancial Analysis. In July of 1998 I left the Commission and joined Columbia as Manager
20 of Regulatory Services. My job title has since been revised to that of Director, Regula-
21 tory Policy.

22

1 Q. What are your responsibilities as Director of Regulatory Policy?

2 A. I am responsible for the management of Columbia's regulatory affairs, tariffs and filings
3 with the Commission, including quarterly Gas Cost Adjustments. I am also responsible
4 for Columbia's local customer service functions.

5
6 Q. Have you previously testified before this or any other regulatory commissions?

7 A: Yes, I have testified once before the Kentucky Public Service Commission in Case No.
8 2002-00117, "The Filing by Columbia Gas of Kentucky, Inc. to Require that Marketers in
9 the Small Volume Gas Transportation Program be Required to Accept a Mandatory As-
10 signment of Capacity".

11
12 Q: What is the purpose of your testimony in this proceeding?

13 A: The purpose of my testimony is to sponsor the proposed modifications to Columbia's
14 tariff pages 1, 2, 3, 5, 6, 7, 7a, 11, 13, 14, 15, 17, 18, 22, 31, 38- 41, 58, 59, 70, 74, 78,
15 83, 89-92, 95-98 and 100-101 set forth in Schedule L according to 807 KAR 5:001 Sec-
16 tion 10(1)(b)(7) and 807 KAR 5:001 Section 10(1)(b)(8). I will also address proposals
17 designed to address the issues of declining customer additions and accelerated replace-
18 ment of bare steel, cast and wrought iron pipe.

19
20 Q: Please provide a general description of the proposed tariff modifications contained in
21 Schedule L of the company's application.

22 A: The rate changes shown on tariff pages 5 through 41 are base rate changes. These
23 changes are supported by the revenue requirement contained in the testimony of Colum-

1 bia witness Humrichouse and the rate design contained in the testimony of Columbia
2 witness Gibbons. Other revisions are proposed to update certain special charges, to im-
3 prove consistency throughout the tariff in dates and terms, to eliminate a page that is no
4 longer applicable, to reorganize the tariff to better segment sales services and transporta-
5 tion services, and to update the form of service agreements required for certain rate
6 schedules. Revisions are proposed to certain elements of Columbia’s Banking and Bal-
7 ancing Service and revised Daily Cash-Out Rates for transportation customers that do not
8 subscribe to Columbia’s Banking and Balancing Service. In addition, I will be support-
9 ing the tariff modification for the proposed Accelerated Main Replacement Program
10 (“AMRP”) Rider.

11
12 Q: It appears Columbia has made many revisions to its tariff. Please explain.

13 A: The revisions appear numerous because Columbia has repositioned many sections of its
14 tariff in an effort to better organize the tariff while making it more user-friendly. Con-
15 ceptually, the tariff basically provides for two types of services – sales service and trans-
16 portation services. There are different classifications of service and customer classes
17 within these two types of services, but all customers fall within one of these categories.
18 Columbia’s tariffs for transportation services originated with the advent of natural gas
19 transportation in the 1980s. The transportation market and customers utilizing transporta-
20 tion services have evolved significantly in the last quarter of a century. Over the years,
21 Columbia has made tariff changes to address some of that evolution, an example being
22 the introduction of the Customer CHOICESM program in 2000. However, Columbia has
23 not previously undertaken an effort to consolidate all elements of transportation service in

1 its tariff. The transportation tariffs originated as subsidiary to the customer's primary
2 designation under a sales service rate schedule. With the proposed revisions, Columbia is
3 eliminating the historic link between sales service and transportation service. The revi-
4 sions allow a customer to more easily identify the options, terms and conditions associ-
5 ated with the services provided by Columbia.

6 Rate Schedule GS (pages 11-12), Rate Schedule IS (pages 13-16) and Rate
7 Schedule IUS 9 pages 22-24 will become sales service tariffs exclusively. Rate Schedule
8 SS (pages 17-18) will be applicable only to rate schedules for transportation services.
9 Rate Schedules for transportation services will each include the title, "Delivery Service"
10 (pages 38-41) and will provide specifically for Grandfathered Delivery Service ("GDS")
11 and Main Line Delivery Service (MLDS").

12
13 Q: What revisions does Columbia propose to its Small Volume Gas Transportation Service
14 Rate Schedule SVGTS and Small Volume Aggregation Service Rate Schedule SVAS?

15 A: Rate Schedule SVGTS (tariff pages 30-32) and Rate Schedule SVAS (tariff pages 33-37)
16 comprise the essential elements of Columbia's Customer CHOICESM program. The
17 Customer CHOICESM program was originated as a pilot by Columbia in Case No. 1999-
18 0165 and expired on March 31, 2005. Upon its expiration, a new CHOICESM pilot pro-
19 gram was authorized by the Commission in Case No. 2004-00462 effective April 1, 2005
20 for a period of four years. Therefore, the only changes proposed at this time are to the
21 Delivery Charges for Rate Schedule SVGTS. The Delivery Charges were established to
22 be identical to the base rate charges for Rate Schedule GS as Columbia's cost to serve a
23 customer is not dependent upon the customer's supplier of the natural gas commodity it-

1 self. Thus, the proposed revisions to Rate Schedule SVGTS (tariff page 31) are the same
2 as those proposed for Rate Schedule GS.

3
4 Q: Columbia proposes adjustments to various special fees and charges in the General Terms,
5 Conditions, Rules and Regulations section of its tariff. Please explain the proposed revi-
6 sions.

7 A: Columbia has experienced an increase in costs for performing certain services and han-
8 dling certain transactions in providing customer service. The fees and charges detailed in
9 this response are those which have historically been identified in the rate-making process
10 as costs that should be borne by those specific customers using the service or causing the
11 cost to be incurred, rather than being allocated among all ratepayers. Columbia identified
12 two special charges as fees that are currently well below associated costs and that are
13 billed a significant number of times. These charges are the reconnect fee set forth on
14 Tariff Sheet 70 and the returned check fee set forth on tariff Sheet 74 of Columbia's tar-
15 iff. The intent of special charges is to assign the cost that the company incurs to the cost-
16 causer. The revisions being proposed are intended to more correctly align the amount of
17 the charge with the actual cost, thus assigning the appropriate costs to the appropriate
18 customers. This is a ratemaking principle to which the Commission has historically ad-
19 hered.

20 The fee for reconnection of service due to disconnection for non-payment of bills
21 or violations of Columbia's rules and regulations was established at the current \$15 in
22 1983, and while Columbia's cost to reconnect service has gone up, the rate has not. Co-
23 lumbia proposes to increase the fee for reconnection of service, except where service was

1 discontinued at the request of the customer, from \$15 to \$55. This revision is set forth on
2 Sheet 70 of Columbia's tariff. Columbia's current Returned Check Fee of \$8 dates back
3 to 1994. Columbia proposes to increase the Returned Check Fee to \$15. This revision is
4 set forth on Sheet 74 of Columbia's tariff.

5 Attachment JMC-1 shows Columbia's cost to provide each of these services. The
6 reconnect fee is based on the full labor and vehicle costs of a one-hour reconnection order
7 which is \$59.52. The returned check fee is based on the average processing time of
8 slightly more than one-half of an hour. This time includes the labor and equipment nec-
9 essary to make attempts to reach the customer, issue new termination orders and enter the
10 appropriate computer codes for processing, the total cost of which is \$17.33.

11
12 Q: What is the impact of Columbia's proposed changes in special fees to its annual revenues
13 for these miscellaneous services?

14 A: Attachment JMC – 2 shows the comparison of Columbia's charges at present and pro-
15 posed rates. Based upon the cost incurred to provide each service, I set the price for each
16 and calculated the increase in each fee. The next column shows the actual number of oc-
17 currences during 2005. Anticipating that the increased charges will impact customer be-
18 havior and reduce the number of future occurrences for each of the charges, I applied a
19 behavioral factor of 75% to the number of occurrences in order to determine the total
20 revenues to be generated by the proposed reconnect and returned check charges.

21
22 Q: Does Columbia propose any revision to its fee to reconnect service that was discontinued
23 at the request of the customer?

1 A: Yes. This charge is applicable to a customer that requests reconnection of service at the
2 same premises within eight months of having requested discontinuance of service at the
3 same location. The intent of this charge is to properly assign costs to those customers
4 who engage in seasonal disconnection of gas service and thereby eliminate an unintended
5 incentive to do so by virtue of a reconnect fee that is less than the aggregate minimum
6 monthly charge. The current fees of \$65 for residential customers and \$176 for other
7 customers were established in 1994 and set forth on Sheet 70 of Columbia's tariff as Co-
8 lumbia's minimum monthly charge for each customer class times eight. Columbia pro-
9 poses to apply the same logic in this application. The resulting reconnect fees are pro-
10 posed to be \$102 ($\12.75×8) for residential customers and \$224 ($\28×8) for commercial
11 and industrial customers.

12
13 Q: Please describe the Banking and Balancing Service currently offered by Columbia and
14 the proposed revisions.

15 A: Columbia currently allows its larger industrial and commercial customers to secure their
16 gas supplies from sources other than Columbia and Columbia has offered related trans-
17 portation, banking and balancing and daily cash-out services. These services enable cus-
18 tomers to bring their own supplies to Columbia with Columbia "balancing" any differ-
19 ences between their actual daily demand and supply on an interruptible basis. Colum-
20 bia's Banking and Balancing Service is an optional service, available under Rate Sched-
21 ule DS, that enables subscribing customers to "bank" differences between the volumes
22 received by Columbia on the customer's behalf and the actual volumes consumed by a
23 customer on a daily basis, subject to limitation on the size of a customer's volume bank.

1 The service provides a bank tolerance of 5% of the Customer's Annual Transportation
2 Volume (Tariff Sheet No. 39) and banked volumes are available for subsequent use by
3 customers on a no-notice basis at the discretion of Columbia. The rate for this service is
4 calculated as set forth in Columbia's quarterly Gas Cost Adjustment to represent Colum-
5 bia's underlying storage cost to provide the service.

6 Columbia does not propose to change the bank tolerance or rate calculation.
7 However, Columbia does propose to rename the section of its tariff (page 91) currently
8 entitled, "Volume Bank" to "Banking and Balancing Service" and transfer the language
9 from Tariff Sheet No. 39 along with certain other changes to insure that the service pro-
10 vided is that offered. The substantive changes are:

- 11 - The first paragraph of this section is revised to reflect the language offered in the
12 Settlement Agreement filed with the Commission in Case No. 2005-00184, cur-
13 rently pending before the Commission.
- 14 - The second paragraph to be labeled, "Cash Out", revises the current cash-out pro-
15 vision, presently based on Columbia's weighted average commodity cost of gas,
16 to tie the cash-out to an indexed market price to better reflect the appropriate price
17 during volatile market periods.
- 18 - The fourth paragraph to be labeled, "Imbalances", is modified to provide an eco-
19 nomic incentive for customers to better manage their volume banks within the
20 prescribed monthly limitations of Columbia's tariff with variances outside of the
21 monthly limitations cashed out at an indexed market price.
- 22 - The paragraph labeled, "Balancing Service Interruption ("BSI") picks up the ex-
23 act language pending before the Commission in Case No. 2005-00184 but

1 changes the term “Daily Delivery Interruption (“DDI”) to Balancing Service In-
2 terruption (“BSI”). BSI is a more descriptive term of the actual measure imple-
3 mented by Columbia to manage its Banking and Balancing Service, because dur-
4 ing a DDI/BSI the customer’s delivery service is not interrupted, only the balanc-
5 ing service is. The penalty charges in this section are the same as the existing
6 penalties and the 3% tolerance for determining compliance is also unchanged.

- 7 - Finally, a new provision is being added, labeled “Monthly Bank Transfers”. This
8 is a practice historically provided by Columbia that should be more properly de-
9 fined and included in its tariff.

10
11 Q: How many of Columbia’s eligible customers currently subscribe to its Banking and Bal-
12 ancing Service and how many have chosen the daily cash-out provision of the existing
13 tariff?

14 A: All of the eligible customers have elected Banking and Balancing Service resulting in no
15 customers on the daily cash-out provision.

16
17 Q: Does Columbia propose any other changes to its tariff?

18 A: Yes. All of the changes are evident in Schedule L to Columbia’s application that con-
19 tains the comparison of current and proposed tariffs. The changes include the following:

- 20 - Establish use of the term and concept of “Customer Charge” to replace the “First 1
21 Mcf or less” rate block of Rate Schedule GS and Rate Schedule SVGTS and add a
22 Customer Charge to Rate Schedule IUS consistent with the proposed rate design of
23 Columbia witness Gibbons. This adjustment in rate design is a step to separate the

1 recovery of fixed system costs from the variable volume of gas delivered to custom-
2 ers and modernize the Company's rate design.

- 3 - Consistently utilizing the date April 1 throughout the tariff as a notification date
4 where a notification date is required.
- 5 - Establish Rate Schedule IS as a sales service rate schedule. This could be considered
6 large-volume sales service as it is available to customers utilizing a minimum of
7 25,000 Mcf annually. There are currently no customers taking sales service under
8 this tariff. The customers have all elected transportation service. The applicable
9 elements of transportation service will be duplicated in Rate Schedule DS for trans-
10 portation customers.
- 11 - Eliminate Tariff Sheet No. 58 – Stranded Cost/Recovery Pool. This page is no longer
12 applicable.
- 13 - Establish Tariff Sheet No. 59 as Columbia's AMRP Rider.

14
15 Q: What is the purpose of Columbia's proposed AMRP Rider?

16 A: The purpose of the AMRP Rider is to establish a mechanism to recover the cost of the
17 Accelerated Main Replacement Program ("AMRP"). This mechanism is identified in
18 Columbia's proposed tariffs as the Accelerated Main Replacement Program Rider (Sheet
19 No.59). As described in the testimony of Columbia witnesses Webb and Humphries, the
20 proposed AMRP is in the public interest, and the financial impact of the program on Co-
21 lumbia over the next 20 years is significant, as described in the testimony of Columbia
22 witness Miller. The mechanism will recognize cost changes and rate base changes di-

1 rectly related to the company's investment in the AMRP and establish a charge, or credit,
2 to customers for the net change in revenue requirement attributable to the AMRP.

3
4 Q: Please describe how Columbia's proposed AMRP Rider will work.

5 A: The AMRP Rider is a tracking mechanism that will allow Columbia to make annual rate
6 adjustments over a 20 year period, in order to recognize cost changes and rate base
7 changes directly related to the proposed AMRP.

8
9 Q: Have similar mechanisms been approved for other distribution utilities?

10 A: Yes. The Commission authorized Duke Energy Kentucky, Inc. (formerly The Union
11 Light, Heat & Power Company) to implement a similar mechanism in Case Nos. 2001-
12 00092 and 2005-00042. Columbia has modeled its mechanism on that approved for
13 Duke Energy - Kentucky. Columbia's program spans 20 years as compared to the 10
14 year program of Duke and includes the replacement of approximately 540 miles of pipe
15 and associated customer service lines. The expected annual investment under the pro-
16 gram is approximately \$9.9 Million per year.

17
18 Q: What are the filing requirements associated with the proposed revenue adjustment for
19 Rider AMRP?

20 A: Columbia proposes to submit its annual adjustment of the AMRP Rider on or about
21 March 1 to be effective with bills rendered in its June billing cycle. The adjustment
22 would be calculated to reflect activity for the prior calendar year and would be subject to
23 Commission review. Columbia proposes to utilize filing formats similar to those pre-

1 scribed by the Commission in Case Nos. 2002-00107 and 2003-00103 for The Union
2 Light, Heat & Power Company in its annual adjustment filings.

3
4 Q: Please describe the calculation of the annual adjustment for the AMRP.

5 A: The computation is a calculation of the return on, and return of, the net change in plant
6 investment attributable to the program converted to an annual revenue requirement
7 amount using traditional ratemaking theory and financial data to be approved in this pro-
8 ceeding. The annual adjustment will be calculated by determining the changes in return
9 on rate base and recovery of expense. The first part of the annual adjustment calculation
10 will determine the change in return on rate base associated with AMRP related invest-
11 ments. The authorized rate of return, adjusted for income taxes as determined in this
12 case, will be applied to the new cumulative AMRP net rate base to calculate the allowed
13 return on AMRP related rate base. The second part of the annual adjustment calculation
14 will determine the change in operating expenses associated with AMRP related invest-
15 ments. This change is a comparison of Depreciation Expense for the various categories
16 of mains, services, meter relocations and customer service lines and Maintenance Ex-
17 pense – Account 887. The net change in return on rate base and recovery of expense as-
18 sociated with the AMRP will be reflected in the AMRP Rider.

19
20 Q: How are the effects of the AMRP on Columbia's operating and maintenance costs treated
21 in the proposed mechanism?

22 A: It is expected that, over time, the AMRP will result in a reduction in Columbia's opera-
23 tion and maintenance expense to repair and maintain the cast iron, bare steel and other

1 mains and services as these facilities are replaced. The annual revenue requirement
2 mechanism proposes to immediately pass on to customers the net reduction in mainte-
3 nance costs which result from the program by comparing the actual amount in Account
4 887-Maintenance of Mains for the prior year to the amount allowed in Account 887-
5 Maintenance of Mains in the Commission's Order in this case.

6
7 Q: How will depreciation expense be treated under Rider AMRP?

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

13
14 Q: Does the tracking mechanism in Rider AMRP mean that Columbia will adjust its revenue
15 requirement to recover its expected investment of \$9.9 Million per year in each year?

16 A: No. The cost of the program is not recovered in each year, or even over 20 years. Here
17 is an example of the calculation provided in Rider AMRP. Assume the previous year's
18 investment under the AMRP is \$9.9 Million. This amount would be reduced by the addi-
19 tional reserve for depreciation (assume this is \$216,810 annually) and deferred income
20 taxes related to the \$9.9 Million investment (assume this amount is \$108,216). Subtract-
21 ing \$216,810 and \$108,216 from \$9,900,000 yields the sum \$9,574,974 which we term
22 the "net rate base for AMRP purposes". The rate of return authorized in this case, ad-
23 justed for taxes, is applied to the net rate base to calculate the return on AMRP related in-

1 vestment. In our example, that means \$9,574,974 times 12.52% (Columbia's proposed
2 return adjusted for taxes) or \$1,198,786. The change in operating expenses associated
3 with the AMRP is the next step. For this example, assume the change in depreciation ex-
4 pense associated with the AMRP plant is \$216,810 and assume that Account 887 – Main-
5 tenance Expense is reduced by \$25,000 in the calendar year. The amount of these
6 changes is summed with the return component to determine the change in Columbia's
7 revenue requirement. In our example, $\$1,198,786 + \$216,810 - \$1,000 = \$1,390,596$.
8 Thus, the Rider AMRP annual adjustment would be \$1,390,596.

9
10 Q: Are there any financial benefits of the AMRP that are not quantified in the proposed rate
11 mechanism?

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

15
16 Q: When does Columbia propose to file its first AMRP Rider filing?

17 A: Columbia proposes to make its first filing by March 1, 2008. This filing would cover
18 AMRP investments during the first year of the program and upon approval, Columbia
19 proposes to follow the certificate process as outlined in the Duke Energy Kentucky, Inc.
20 case.

21
22 Q: How does Columbia propose to handle the gap that will exist in investment between its
23 test year, used to establish the base rates in this case, and the initial AMRP?

1 A: The end of the test year in this proceeding is September 30, 2006. Columbia proposes to
2 include in its first AMRP Rider filing the information concerning plant, accumulated de-
3preciation and deferred income taxes relating to retirements and replacements occurring
4between September 30, 2006 and the beginning of the AMRP in order to avoid including
5in the AMRP Rider the effect of any retirements or replacements of cast iron and unpro-
6tected steel pipe not a part of the AMRP.

7

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

9 A: As indicated in Columbia witness Miller's testimony, the ability to recover the deprecia-
10tion and carrying costs related to the capital investment, less operating expense reduc-
11tions, diminishes Columbia's need to file frequent rate case applications. However,
12should a general rate case be filed during the AMRP period, the program investment and
13reduced operating expense should be included in base rates and the Rider AMRP reset to
14zero.

15

16 Q: Have you estimated the annual revenue requirement attributable to the AMRP for each of
17the next 20 years?

18 A: Yes. Attachment JMC-3 reflects an estimated revenue requirement attributable to the
19AMRP for each of the next 20 years. The numbers are for illustration only as no amounts
20are included for the savings in Account 887-Maintenance of Mains expense and the per
21customer impact is calculated based on a straight per number of customers basis. Co-
22lumbia proposes to actually allocate the AMRP related revenue requirement among cus-
23tomer classes based on the overall base revenue distribution approved in this case. The

1 revenue adjustment allocated to each class would be converted to a per customer charge
2 based on the number of customers in each class. No revenue adjustments would be allo-
3 cated to customers served under Rate Schedule MLDS or the Flex Provision of Rate
4 Schedule DS. This is consistent with the rate design testimony of Columbia witness Gib-
5 bons and the company's effort to align fixed costs with fixed charge recovery.

6
7 Q. Does Columbia have any other proposals to address the changes Columbia has experi-
8 enced on its system?

9 A. Yes, as Columbia witnesses Miller and Moul state, Columbia has experienced a decline
10 in the number of new customers who are choosing to connect to Columbia's lines. This
11 means that any increase in fixed costs will fall on the existing customer base, thereby
12 placing an upward pressure on those customers' rates. As a general rule, when a utility's
13 costs increase it is desirable to have a larger customer base over which to spread the
14 costs, in order to keep a downward pressure on rates. In order to maintain reasonable
15 rates for its customers, Columbia developed a method which will encourage customer
16 growth in a cost-effective manner.

17
18 Q: What proposal does Columbia have to encourage customer growth?

19 A: Columbia is committed to addressing and understanding its declining customer growth
20 and seeks an innovative program to allow it to defer certain costs associated with invest-
21 ment in facilities to serve new customers. This would better position the company to in-
22 vest in additional capital needed to serve new customers by eliminating the negative im-
23 pact of regulatory lag between rate cases when the company is incurring expenses related

1 to plant investments that have not yet been included in rate base. Specifically, Columbia
2 proposes to capitalize interest after plant is placed in service until it is placed in rate base,
3 and to defer depreciation expense and property tax on the same plant additions until it is
4 placed in rate base. Columbia terms this accounting treatment, "PISCC" which stands for
5 Post In-Service Carrying Charges. Columbia envisions that, over time, with this program
6 it will see an improved growth in number of customers.

7
8 Q: What facilities investment would be eligible for PISCC accounting treatment?

9 A: PISCC would be applicable only to the original cost of plant additions for new business
10 projects. PISCC would not apply to any AMRP-related investments. Plant additions eli-
11 gible for PISCC accounting treatment would be tracked by Job Order and are identified in
12 Attachment JMC - 4. Eligible investments would be new business job orders initiated on
13 and after the date of the Commission's Order approving the proposed PISCC and con-
14 tinuing for new business projects initiated in subsequent calendar years.

15
16 Q: How does Columbia propose to determine the rate at which it will capitalize interest?

17 A: Columbia proposes to define the interest rate at which it will capitalize interest on eligible
18 investments as the "PISCC Rate". The rate will be determined in this case as the
19 weighted average cost of debt authorized in the Commission's Order in this case. The
20 PISCC rate excludes equity and there is no compounding. See Attachment JMC-5 for the
21 calculation of Columbia's proposed PISCC rate. The rate would remain in effect until a
22 new rate is determined in the next applicable regulatory Q: How does Columbia propose
23 to calculate the depreciation deferral?

1 A: The depreciation deferral will be calculated on eligible investment at the depreciation
2 rates authorized by the Commission in this case.

3

4 Q: How does Columbia propose to calculate the deferral for property tax?

5 A: Property taxes shall be calculated on all eligible property at Columbia's estimated com-
6 posite property tax rate for the applicable calendar year and deferred in special sub-
7 accounts of Account 182 - Other Regulatory Assets. This rate shall be estimated for the
8 current year with appropriate adjustments as actual data becomes available. The tax base
9 upon which this rate shall be applied is defined as the ratio of the net book value of eligi-
10 ble property to the net book value of all property located in Kentucky times the total as-
11 sessed value of the company's assets located in Kentucky.

12

13 Q: How will Columbia track PISCC?

14 A: PISCC will be calculated and segregated into special sub-accounts by the Accounting
15 Department as completed construction orders are received and accrue until the assets are
16 placed into rate base in a regulatory proceeding.

17

18 Q: What is Columbia's proposal regarding recovery of PISCC?

19 A: Recovery of PISCC would be in the context of the normal rate case process. With Co-
20 lumbia's next rate case, the assets will be included in rate base to be amortized over the
21 life of the asset and include a return on the cost of the investment. The Commission
22 would review and verify the PISCC accounts on Columbia's books. PISCC accrued on
23 eligible new business investments would be included in rate base, except to the extent

1 that any portion of the associated investment would be excluded from rate base as impru-
2 dent or unreasonable in the Commission's Order. Columbia's witness Konold discusses
3 the accounting entries that will be applicable to PISCC.

4

5 Q: Is Columbia aware of any other state regulatory bodies that have authorized a PISCC
6 program?

7 A: Yes. Columbia Gas of Ohio has a similar accounting treatment. However, the Ohio pro-
8 gram is broader in scope as it is applicable to almost all capital expenditures, not just new
9 business projects.

10

11 Q: Does this complete your Prepared Direct Testimony?

12 A: Yes, it does.

COLUMBIA GAS OF KENTUCKY
COST ANALYSIS
SPECIAL CHARGESReconnect Fee (Other than at Customer request)

CKY Service Technician - Base Labor (1 Hour)	\$23.00
Overheads and Vehicle Charges	<u>36.52</u>
Total Cost	\$59.52

Returned Check Fee

Clerical Base Labor - 1/2 Hour @ \$19 per hour	\$9.50
Data Processing Labor Entry	\$0.83
Overheads to base labor @ \$14 per hour	<u>7.00</u>
Total Cost	\$17.33

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

Ln. No.	Year	2007	2008	2009	2010	2011	2012	2013	2015	2016	2017
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
1	Cumulative Spend	9,900,000	19,800,000	29,700,000	39,600,000	49,500,000	59,400,000	69,300,000	79,200,000	89,100,000	99,000,000
2	Reserve for Depreciation	216,810	650,430	1,300,860	2,168,100	3,252,150	4,553,010	6,070,680	7,805,160	9,756,450	11,924,550
3	Deferred income taxes	108,216	497,947	1,132,608	1,979,465	2,960,725	4,009,726	5,129,472	6,333,441	7,633,803	9,040,648
4	Net rate base (Ln. 1 less Lns. 2 & 3)	9,574,974	19,474,974	28,551,623	37,166,532	45,352,435	53,187,125	60,737,264	67,999,848	74,961,399	81,609,747
5	Depreciation - Annual @ 2.19% (Ln. 1 * 2.19%)	216,810	433,620	650,430	867,240	1,084,050	1,300,860	1,517,670	1,734,480	1,951,290	2,168,100
6	Return @ pretax rate of return (Ln. 4 * ROR below)	1,198,930	2,438,559	3,575,091	4,653,807	5,678,805	6,659,826	7,605,217	8,514,601	9,386,292	10,218,764
7	Property Taxes, uncollectibles & PSC Fees	-	-	-	-	-	-	-	-	-	-
8	Savings - Reductions in Account 887.	-	-	-	-	-	-	-	-	-	-
9	Annual Costs	1,415,740	2,872,179	4,225,521	5,521,047	6,762,855	7,960,686	9,122,887	10,249,081	11,337,582	12,386,864
10	Customers @ 9/30/06	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981
11	Annual Customer costs (Ln. 8/Ln. 9)	10.41	21.12	31.07	40.6	49.73	58.54	67.09	75.37	83.38	91.09
12	Monthly Customer costs	0.87	1.76	2.59	3.38	4.14	4.88	5.59	6.28	6.95	7.59

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

Ln. No.	Year	2018 (\$)	2019 (\$)	2020 (\$)	2021 (\$)	2022 (\$)	2023 (\$)	2024 (\$)	2025 (\$)	2026 (\$)	2027 (\$)
1	Cumulative Spend	108,900,000	118,800,000	128,700,000	138,600,000	148,500,000	158,400,000	168,300,000	178,200,000	188,100,000	198,000,000
2	Reserve for Depreciation	11,425,558	14,027,278	16,845,808	19,881,148	23,133,288	26,602,258	30,288,028	34,190,608	38,309,998	42,646,198
3	Deferred income taxes	10,551,781	12,152,722	13,841,160	15,617,056	17,480,449	19,317,693	21,014,834	22,572,219	23,989,501	25,380,634
4	Net rate base (Ln. 1 less Lns. 2 & 3)	86,922,661	96,822,661	102,520,000	107,913,032	113,001,796	117,786,253	122,380,049	126,897,138	131,337,173	135,700,501
5	Depreciation - Annual @ 2.19% (Ln. 1 * 2.19%)	2,384,910	2,601,720	2,818,530	3,035,340	3,252,150	3,468,960	3,685,770	3,902,580	4,119,390	4,336,200
6	Return @ pretax rate of return (Ln. 4 * ROR below)	10,884,021	12,123,649	12,837,042	13,512,330	14,149,520	14,748,606	15,323,818	15,889,425	16,445,384	16,991,738
7	Property Taxes, uncollectibles & PSC Fees	-	-	-	-	-	-	-	-	-	-
8	Savings - Reductions in Account 887.	-	-	-	-	-	-	-	-	-	-
9	Annual Costs	13,268,931	14,725,369	15,655,572	16,547,670	17,401,670	18,217,566	19,009,588	19,792,005	20,564,774	21,327,938
10	Customers @ 9/30/06	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981	135,981
11	Annual Customer costs (Ln. 8/Ln. 9)	97.58	108.29	115.13	121.69	127.97	133.97	139.8	145.55	151.23	156.84
12	Monthly Customer costs	8.13	9.02	9.59	10.14	10.66	11.16	11.65	12.13	12.6	13.07
13	Capital Structure										
14	Short term Debt										
15	Long term Debt										
16	Equity										
17	Total										
		<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>	<u>Pre-Tax @ 38.90%</u>						
		5.296%	5.60%	0.30%	0.30%						
		42.617%	5.69%	2.42%	2.42%						
		<u>52.087%</u>	<u>11.50%</u>	<u>5.99%</u>	<u>9.80%</u>						
		100.00%	8.71%	8.71%	12.52%						

CKY Distribution Plant

The following Budget Accounts are eligible for PISCC treatment

Budget

547	<u>Electronic Flow – Computers/ Correctors – New Business</u>
549	<u>Automatic Meter Reading Devices – New Business</u>
555	<u>Mains - New Business</u>
563	<u>Service Lines - New Business:</u>
567	<u>Meters – New Business</u>
569	<u>Meter Installations – New Business</u>
571	<u>House Regulators – New Business</u>
573	<u>Plant Regulators – New Business</u>
575	<u>Regular Sites – New Business</u>
577	<u>Regular Structures – New Business</u>

Columbia Gas of Kentucky Computation of the PISCC Rate

		Amount	Capitalization Ratio	Cost Rate	Weighted Cost
Short-term Debt	*	8,052,233	11.05%	5.60%	0.62%
Long-term Debt	*	<u>64,791,243</u>	<u>88.95%</u>	5.69%	<u>5.06%</u>
Total Debt		72,843,476	100.00%		5.68%

* Based on Columbia Gas of Kentucky's application in Case No. 2007-00008

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia)
Gas of Kentucky, Inc.) Case No. 2007- 00008

**PREPARED DIRECT TESTIMONY OF
KELLY HUMRICHOUSE
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.**

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February 1, 2007

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

1 **PREPARED DIRECT TESTIMONY OF KELLY HUMRICHOUSE**

2 Q: Please state your name and business address.

3 A: Kelly Humrichouse, 200 Civic Center Drive, Columbus, Ohio 43215.

4

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

6 A: I am employed by NiSource Corporate Services Company (“Corporate Services”). My
7 current title is Director of Regulatory Accounting.

8

9 Q: What are your responsibilities as Director?

10 A: As Director, my principal responsibilities include overseeing regulatory-related services for
11 NiSource subsidiaries, including regulatory compliance filings such as gas cost recovery
12 filings, and base rate case support as requested by the NiSource energy distribution
13 companies.

14

15 Q: What is your educational and professional background?

16 A: I received a Bachelor of Science degree in Accounting in 1985 from Franklin University
17 located in Columbus, Ohio. I also received a Master of Business Administration from the
18 University of Dayton in 1994.

19

20 Q: What are your professional credentials?

21 A: I am a Certified Public Accountant, and am currently a member of both the Ohio Society
22 of Certified Public Accountants (“OSCPA”) and the American Institute of Certified
23 Public Accountants (“AICPA”).

1 Q: Please briefly describe your professional experience.

2 A: I have been employed in various positions within the Columbia Energy Group and its
3 successor, NiSource Inc., in capacities related to regulatory compliance, regulatory and
4 general accounting, auditing, financial planning and forecasting since May 1986. In
5 February 2004, I was named Director of Regulatory Accounting, which is the position I
6 currently hold.

7

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

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

14

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

16 A: The test period contains the actual twelve months ended September 30, 2006, adjusted for
17 known and measurable changes, and the plant valuation is as of September 30, 2006.

18

19 Q: Please refer to Schedule A and describe the information presented there.

20 A: Schedule A provides Columbia's Overall Financial Summary. Schedule A, Line 8 shows
21 the calculation of the revenue deficiency in this case of \$12,645,522. This amount
22 represents the increase in revenue that is required by Columbia Gas of Kentucky, Inc.
23 ("Columbia" or "the Company") to earn an overall rate of return on rate base of 8.71%,

1 the return recommended by Columbia witness Moul. On Line 9, the requested revenue
2 increase of approximately \$12.6 million is presented. This is the level of revenue that is
3 supported by Columbia's proposed rates, and is therefore the adjustment to revenue that
4 Columbia is requesting in its Application.

5
6 Q: Please describe the schedules presented in Schedule B of Columbia's Application.

7 A: Schedule B presents the Company's rate base and consists of eight schedules.

8 The information shown on Schedule B-1 is the rate base summary supported by various
9 schedules in Section B of Columbia's Application. The plant in service and reserve for
10 accumulated depreciation and amortization as of September 30, 2006 are summarized on
11 Schedules B-2, B-3 and B-4. The working capital component is summarized on Schedule
12 B-5, and other rate base items are shown on Schedule B-6. Schedule B-7 reports the
13 allocation factors and Schedule B-8 contains comparative balance sheet information.

14
15 Q: Please describe in detail the individual supporting schedules.

16 A: Schedule B-2 shows the investment in gas plant in service by major property grouping as
17 of the plant valuation date of September 30, 2006. The amount in the column labeled
18 "Based Period Adjusted Jurisdictional" represents plant in service that is used and useful
19 in providing gas service to Columbia's customers. Schedules B-2.1 through B-2.7
20 provide a more detailed presentation of the gas plant in service, including a breakdown
21 by FERC account and detail of plant additions and retirement.

22 Schedule B-3 shows the total plant investment and the Reserve for Accumulated
23 Depreciation and Amortization by FERC Account groupings as of September 30, 2006.

1 Schedule B-3.1 summarizes adjustments to the reserve. Columbia has not proposed any
2 adjustments in this case.

3 Schedule B-3.2 lists the jurisdictional plant investment and reserve balance at
4 September 30, 2006 for each FERC Account within each major property grouping. It also
5 shows the proposed depreciation accrual rates, calculated annual depreciation and
6 amortization expense on plant in service as of September 30, 2006 excluding construction
7 work in progress in service, percentage of net salvage, average service life and curve
8 form, as applicable, for each account. In this Application, Columbia is filing with the
9 Commission proposed depreciation accrual rates and amortization accrual rates for
10 tangible property. Except for the amortization rates on intangible property, the proposed
11 depreciation and amortization accrual rates, as shown in Column G are supported by Mr.
12 Spanos and are included in his study as provided in response to the Commission's
13 standard filing requirement 6-N. The amortization rates for intangible property, which
14 consist mostly of software costs, are established by the company consistent with its
15 policy on amortization of intangible property. The calculated depreciation and
16 amortization expense are provided by Mr. Spanos except for the amount of intangible
17 property which is the test year level of expense.

18 Schedule B-4 is a list of construction work in progress by major property
19 grouping at September 30, 2006. Certain balances remain in Account 107 – Construction
20 Work in Progress; however, the plant has been placed in service. These amounts have
21 been identified on Schedule B-4 and have been included in rate base.

22

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

3 A: There are many reasons that plant may be placed in service, but for accounting purposes,
4 has not been transferred to Account 101 or Account 106. For instance, items that are
5 purchased on a blanket work order, such as office equipment, computers, tools, meters,
6 etc., are “in service” at the time of purchase. A second example includes specific projects
7 that may have been flagged as “in or ready for service” however, for accounting purposes
8 have not been moved to Account 101 or Account 106 because all invoices have not been
9 received or billings have not been completed. In general, it takes two to three months to
10 map and close projects from Account 107 to Account 101 or Account 106.

11
12 Q: Please describe the calculation of cash working capital and other working capital
13 allowances as shown on Schedules B-5 and B-5.1.

14 A: The total level of working capital that I am supporting in this case is shown on Schedule
15 B-5, Sheet 1. The working capital is made up of a component for cash working capital
16 shown on Line 1, Materials and Supplies shown on Line 3, Storage Balance on Line 4,
17 and Prepayments shown on Line 5.

18
19 Q: How was the Cash Working Capital Allowance developed?

20 A: Cash Working Capital is calculated by taking total operation and maintenance expenses
21 for the twelve months ended September 30, 2006 (excluding gas costs) and multiplying
22 by 1/8 or 12.25%. This method, commonly referred to as the “formula method,” is the

1 traditional methodology that has been approved by the Commission in Columbia's
2 previous rate filings.

3

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

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

11

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

13 A: All of the other working capital items were calculated on Schedule B-5.1 by taking an
14 average of the monthly balances for the thirteen months ended September 30, 2006. Due
15 to the monthly fluctuations in these balances, I determined the working capital allowance
16 based on the thirteen-month average balance. Using a thirteen-month average balance
17 allows the entire test period activity to be considered in the rate base computation. The
18 Commission has accepted this method in prior rate proceedings.

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

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

6

7 Q: Please continue with Schedule B-7.

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

12

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

15 A: Yes, Schedule B-8 contains comparative balance sheet information required pursuant to
16 807 KAR 5:001, Section 10.

17

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

19 A: Schedule C-1 sets forth Columbia’s pro forma operating income summary for the twelve
20 months ended September 30, 2006. This schedule includes the operating income
21 summary at both current and proposed rates. The adjusted operating results at both
22 current and proposed rates are summarized on Schedule C-2. The revenue at proposed
23 rates was developed by adding the revenue increase to the current operating revenues.

1 The related increase to expenses and taxes on the proposed revenue increase was
2 subtracted from the current adjusted operating results to determine the jurisdictional pro-
3 forma amounts and the corresponding rate of return. The rate base as shown on this
4 schedule is calculated on Schedule B-1.

5
6 Q: What is presented in Schedule C-2?

7 A: Schedule C-2 sets forth the current operating results for the twelve months ended
8 September 30, 2006 at both unadjusted and adjusted levels. The unadjusted operating
9 results are summarized from Schedule C-2.1. Monthly and year over year comparison
10 information is provided on Schedule C-2.2 for the expense items included in Total
11 Operating Expense as provided on Schedule C-2.1 and the revenue items included in
12 Total Operating Revenue as provided on Schedule C-2.1. The adjusted amounts include
13 the effects of the adjustments summarized on Schedule D-1.

14
15 Q: Please describe Schedule C-2.1.

16 A: Schedule C-2.1 sets forth the detail of Columbia's operating results for the twelve months
17 ended September 30, 2006 and the jurisdictional allocation of those operations. The
18 operating results as shown on this Schedule C-2.1 are listed by account and are
19 summarized on Schedule C-2.

1 Q: Did you prepare a comparison of revenue and expenses for the test year and the prior
2 year?

3 A: Yes, Schedule C-2.2 contains a comparison of gas revenue and expense for the twelve
4 months ended September 30, 2006 to the twelve months ended September 30, 2005 by
5 FERC account. It also contains a similar monthly comparison for each month in the test
6 period. Variances from prior periods are given in dollars and percentages for the year.

7

8 Q: Have you made any adjustments to the Operation and Maintenance Expense levels that
9 are shown on Schedule C-2.1?

10 A: Yes, Schedule D-1 is a summary of the detailed adjustments to test period operating
11 revenues and operating expenses as set forth in Schedules D-2.1 through D-2.11. These
12 adjustments show the test period revenue and expense at the level that would have been
13 incurred if known and measurable changes had been in effect during the entire test
14 period. These adjustments are necessary so that prevailing revenue and expenses,
15 incurred during the twelve-month test period, are properly reflected in establishing the
16 appropriate level of rates. Rates should be set at a level that reflects the current, and on-
17 going, level of costs that are to be recovered during the period of time the rates are in
18 effect.

19

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

21 A: Taxes are adjusted to reflect those applicable changes resulting from the adjustments
22 described in my testimony, including taxes other than income taxes, and state and federal

1 income taxes. These tax adjustments along with the rates used to develop these
2 adjustments are shown for each individual adjustment on Schedule D-1.

3
4 Q: Did Columbia adjust revenue for the test year?

5 A: Yes, Schedule D-2.1 reflects an annualization of base revenues, which adjusts actual
6 revenues to a level that would have been recognized if the current rates and customers
7 had existed during the entire test period. It reflects several revenue and expense
8 adjustments. First, revenue has been adjusted for weather normalized sales volumes for
9 the twelve months ended September 30, 2006. Second, revenues and related gas costs for
10 the twelve months ended September 30, 2006 have been calibrated to reflect the
11 annualization of sales and transportation volumes from customer levels as of September
12 30, 2006. Finally, annualized revenue reflects an adjustment to reconcile the Energy
13 Assistance Program (“EAP”) surcharge revenue with EAP expense.

14 The calculations of the weather normalization and annualized year-end customer
15 adjustments were developed by Columbia witnesses Balmert and Gresham and are
16 supported by their testimonies. Schedule D-2.1 also reflects the annualization of gas cost
17 recovery revenue based on the most current gas cost recovery rate in effect. Operating
18 expenses and Taxes Other than Income have also been adjusted for the effect of
19 uncollectible accounts and the Kentucky Public Service Commission (“KPSC”)
20 assessment on the annualized test year revenue. These adjustments are summarized on
21 Schedule D-1, Sheet 1.

1 Q: Please summarize the impact of the adjustment included in Schedule D-2.1.

2 A: The adjustment results in a net revenue decrease of (\$29,390,256) including adjustments
3 for items as described above. The adjustment also results in a net decrease in operation
4 and maintenance expenses of (\$29,036,816) including adjustments for uncollectible, gas
5 purchase costs and KPSC fees.

6

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

9 A: Columbia's test year expense level does not include advertising expenditures for political,
10 promotional or institutional advertising as specifically disallowed.

11

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

13 A: Schedule D-2.2 reflects an adjustment to provide for recognition of annualized labor
14 costs based on employee count and labor rates at September 30, 2006. The schedule
15 reflects an adjustment to include expected merit increases for union employees, including
16 overtime and premium costs, effective with wages beginning December 1, 2006 and
17 December 1 2007. This schedule also reflects a 3.5% increase for all other employees.
18 This 3.5% increase is anticipated to be effective March 1, 2007. The total adjustment
19 increases operating expense by \$70,225 after consideration for capitalized costs.

20

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

22 A: Schedule D-2.3 develops an adjustment to increase the test year incentive compensation
23 level to an anticipated future level. This schedule removes an out of period adjustment

1 from Columbia's per books test year level and adjusts to an anticipated level using
2 Columbia's recent historic incentive program parameters.

3
4 Q: Has Columbia experienced an increase in the costs of its major employee benefits?

5 A: Yes, Schedule D-2.4 also reflects anticipated significant future increases. The total
6 benefit adjustment shown on Schedule D-2.4 is \$267,001 of which Other Post
7 Employment Benefit ("OPEB") costs are decreased by (\$56,248) for both medical and
8 group life, employee insurance plans are increased by \$203,753, pensions and retirement
9 income is increased by \$111,570 and thrift plan is increased by \$7,925.

10
11 Q: Please explain the rent expense adjustment shown on Schedule D-2.5.

12 A: Schedule D-2.5 provides an adjustment to remove the reversal of a General Office
13 building lease write-down made in a prior period. This reversing adjustment was made in
14 Columbia's test year as a reduction to rent expense of \$407,211. The original lease
15 write-down expense entry was made to recognize vacated floors not utilized as a result of
16 the 2000 merger between NiSource and Columbia Energy Group. These floors are now
17 being used. Schedule D-2.5 adjusts this amount to more appropriately reflect anticipated
18 and on-going rent expense by removing this non-recurring item.

19
20 Q: Have you reflected the new depreciation rates as proposed by Columbia witness Spanos?

21 A: Yes, Schedule D-2.6 reflects an increase in depreciation expense based on proposed
22 depreciation rates filed in this proceeding and plant in service at September 30, 2006.

1 The resulting adjustment is \$2,079,946. This adjustment includes no change to the
2 amortization levels as of September 30, 2006.

3
4 Q: Is Columbia proposing to recover costs incurred in preparing this case?

5 A: Schedule D-2.7 reflects an adjustment to operating expense to reflect the estimated costs
6 for the development of this case. This includes the costs of the legal notice, consultants
7 retained, legal fees, and miscellaneous costs such as travel and supplies expense. The
8 total estimated amount of \$255,000 has been divided by three years, which is the
9 proposed amortization period. This amortization period represents the average time
10 between rate cases since 1975 rounded up to the nearest full year. The resulting
11 adjustment is \$85,000.

12
13 Q: Have you made any adjustments to the test year level of NiSource Corporate Services
14 Company's ("NCSC") charges?

15 A: Yes. The company's test year level of NCSC costs charged to expense of \$9,265,162, as
16 shown on Line 3 of Schedule D-2.8, is not representative of Columbia's going level of
17 costs. The amounts includes Columbia's portion of one time costs incurred by NCSC to
18 implement the IBM contract. Also, the going level of IBM costs included in the test year
19 does not reflect the IBM level, under terms of contract, expected to be incurred during the
20 first full year new rates would be in effect.

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

2 A: As shown on Line 7 of Schedule D-2.8, I included \$8,974,936 of NCSC costs which
3 represents Columbia's projected calendar year 2007 level of NCSC costs, net of
4 capitalization. The projected level reflects the latest IBM cost level and the ongoing
5 NCSC costs increased for labor and benefits. These are supported by witness Susanne
6 Taylor.

7
8 Q: Did you make any other adjustments to the NCSC costs?

9 A: Yes, I made two other adjustments. The first relates to one time costs incurred by NCSC
10 to implement the IBM contract and other efficiency and cost containment efforts. These
11 costs were incurred commencing in the second quarter of 2005 and Columbia's portion of
12 the cumulative one-time costs are detailed on Sheet 2 of 2 of Schedule D-2.8 and total
13 \$3,333,558. I propose to amortize these costs over three years. The annual amount is
14 \$1,111,186 and is included on Line 8 of Schedule D-2.8. This adjustment includes
15 implementation costs related to Work Management System, Transition, Consulting, and
16 Restructuring costs as well as other one-time costs more minor in nature incurred to
17 provide future cost containment and efficiencies. These are further supported by witness
18 Susanne Taylor.

19 The second adjustment reflects the elimination of one-time costs incurred directly
20 by Columbia and included in O&M expense. These costs were incurred directly by
21 Columbia and not billed via NCSC, but were related to the implementation of the IBM
22 contract. The adjustments made were related to severances, out-placement services and

1 other costs to achieve. The credit adjustment included in O&M expense totals \$188,891
2 and is shown on Line 9 of Schedule D-2.8.

3

4 Q: How will Columbia treat the amortization of one time costs associated with the
5 implementation of the IBM contract?

6 A: Columbia through this filing is requesting that the Commission grant it authority to
7 recognize a regulatory asset to record these charges that would otherwise be expensed as
8 incurred. This treatment is pursuant to the provisions of SFAS No. 71, "Accounting for
9 the Effects of Certain Types of Regulation". Columbia is further requesting the ability to
10 amortize these costs over time in a manner which more closely matches recovery of such
11 costs with expense.

12

13 Q: What is the total NCSC adjustment to test year O&M expense?

14 A: The adjustments total \$1,009,851 and are shown on Lines 10 and 12 of Schedule D-2.8.

15

16 Q: What is the purpose of the adjustment shown on D-2.9?

17 A: Schedule D-2.9 reflects the annualization of property and liability insurance expense at
18 levels in effect at the end of the test year. Corporate insurance expense is expensed on a
19 fiscal year ending June. Therefore, the test year includes a partial year at prior rates and a
20 partial year at current rates. This adjustment of \$113,447 annualizes property and
21 liability insurance expense at the current level.

22

23

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

2 A: Yes, the adjustment captured on Schedule D-2.10 provides for recognition of test year-
3 end annualized FICA taxes in the development of the cost of service. This adjustment
4 also gives recognition to the taxes related to decreased payroll as shown on Schedule D-
5 2.2 and increased incentive compensation as shown on Schedule D-2.3. This reduction is
6 partially offset by recognizing an increase in the individual level of maximum pay subject
7 to Social Security. The total adjustment is \$21,891.

8

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

10 A: Schedule D-2.11 reflects the annualization of property levels in effect at the end of the
11 test year. This adjustment totals \$111,502. Columbia recently settled its property tax
12 valuation protests for tax years 2004 and 2005 with the Kentucky Department of Revenue
13 that resulted in out of period credit adjustments in the amount of \$118,256 for which
14 property tax expense should be increased. This should be partially offset by an
15 adjustment for a \$6,754 out of period charge for West Virginia property taxes on stored
16 gas for tax year 2005.

17

18 Q: Does this complete your Prepared Direct Testimony?

19 A: Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia)
Gas of Kentucky, Inc.) Case No. 2007-00008

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

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February 1, 2007

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

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

	<u>Page No.</u>
PREPARED DIRECT TESTIMONY OF PAUL R. MOUL.....	1
INTRODUCTION AND SUMMARY OF RECOMMENDATIONS	1
FUNDAMENTAL RISK ANALYSIS	12
CAPITAL STRUCTURE RATIOS.....	18
COST OF SENIOR CAPITAL.....	22
COST OF EQUITY – GENERAL APPROACH	22
DISCOUNTED CASH FLOW ANALYSIS	23
RISK PREMIUM ANALYSIS	41
CAPITAL ASSET PRICING MODEL	47
COMPARABLE EARNINGS APPROACH.....	51
CONCLUSION ON COST OF EQUITY.....	55
Appendix A - Educational Background, Business Experience and Qualifications	
Appendix B -- Ratesetting Principles	
Appendix C – Evaluation of Risk	
Appendix D - Cost of Equity - General Approach	
Appendix E - Discounted Cash Flow Analysis	
Appendix F - Flotation Cost Adjustment	
Appendix G - Interest Rates	
Appendix H - Risk Premium Analysis	
Appendix I - Capital Asset Pricing Model	
Appendix J - Comparable Earnings Approach	

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
FERC	Federal Energy Regulatory Commission
Flot.	Flotation costs
FOMC	Federal Open Market Committee
g	Growth rate
GDP	Gross Domestic Product
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
M&A	Merger & Acquisition
MLP	Master Limited Partnerships
PUC	Public Utility Commission
PUHC	Public Utility Holding Company
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth

PREPARED DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q: What is the purpose of your testimony?

A: My testimony presents evidence, analysis and a recommendation concerning the appropriate 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.

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

3 A: My conclusion is that the Company should be afforded an opportunity to earn a rate of
4 return on common equity within the range of 11.25% to 11.75%. From this range, I
5 recommend that the Company employ an 11.50% rate of return on common equity. With
6 this return, I have presented the weighted average cost of capital for the Company as shown
7 on Attachment PRM-1. The weighted average cost of capital is based upon Columbia of
8 Kentucky's capitalization adjusted for market based capital structure ratios (see page 1 of
9 Attachment PRM-5). The resulting overall cost of capital, which is the product of
10 weighting the individual capital costs by the proportion of each respective type of capital,
11 should establish a compensatory level of return for the use of capital and provides the
12 Company with the ability to attract capital on reasonable terms.

13

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

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

1 The Company provides natural gas distribution service to approximately 141,000
2 customers in central and eastern Kentucky. Throughput to these customers in 2005 was
3 represented by approximately 20% to residential customers, 10% to commercial customers,
4 2% to industrial, sales for resale and off-system customers, and 69% to transportation
5 customers. Industrial customers comprise just 112 customers, or approximately one-tenth
6 of one percent of the Company's customers. This means that the energy needs of a few
7 customers can have a significant impact on the Company's operations.

8 The Company's flowing gas is provided by transportation arrangements
9 with interstate pipelines and with local producers. The Company supplements its flowing
10 gas supplies with gas withdrawn from underground storage. Approximately 77% of the
11 Company's customers use natural gas for space heating purposes. Also, approximately
12 21% of its customers utilize the Company's transportation service.

13
14 Q: How have you determined the cost of common equity in this case?

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

21

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

3 A: The Commission should consider the rate-setting principles that I have set forth in
4 Appendix B. In this regard, the Commission's rate of return allowance must provide a
5 utility with the opportunity to cover its interest and dividend payments, provide a
6 reasonable level of earnings retention, produce an adequate level of internally generated
7 funds to meet capital requirements, be adequate to attract capital in all market conditions,
8 be commensurate with the risk to which the utility's capital is exposed, and support
9 reasonable credit quality.

10

11 Q: What factors have you considered in measuring the cost of equity in this case?

12 A: The models that I used to measure the cost of common equity for the Company were
13 applied with market and financial data developed from my proxy group of eight natural gas
14 companies. The proxy group consists of natural gas companies that: (i) are engaged in the
15 natural gas distribution business, (ii) have publicly-traded common stock, (iii) are
16 contained in The Value Line Investment Survey, (iv) have a history of increased dividends
17 over the period 2001-2005, (v) are not currently the target of a merger or acquisition, and
18 (vi) have at least 70% of their assets subject to utility regulation. The companies in the
19 proxy group are identified on page 2 of Attachment PRM-3. I will refer to these companies
20 as the "Gas Group" throughout my testimony.

21

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

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

9

10 Q: Please summarize your cost of equity analysis.

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

DCF	9.71%
RP	11.44%
CAPM	13.06%
Comparable Earnings	14.30%
Average	12.13%
Median	12.25%
Mid-point	12.01%

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Focusing upon the market model approaches of the cost of equity (i.e., DCF, RP and CAPM), the average equity return produced is 11.40% ($9.71\% + 11.44\% + 13.06\% = 34.21\% \div 3$). From all these measures, I determined that the Company's cost of equity is within the range of 11.25% to 11.75%. I recommend that the Commission set the Company's rate of return on common equity at 11.50%, or at the midpoint of the range to calculate its weight average cost of capital. My cost of equity recommendation makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events.

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I should note that at this time, the DCF model is providing atypical results. That is to say, the low DCF returns can be traced in part to the unfavorable investor sentiment for the gas companies. Indeed, the average Value Line Timeliness Rank for my Gas Group is "4," which places them in the below average category and signifies that they are relatively unattractive investments. Moreover, page 5 of Attachment PRM-13 shows that the gas distribution companies are ranked 77 out of 96 industries for probable performance over the next twelve months. The significance of this low ranking is that performance for

1 this group is expected to be subpar, thereby indicating that the DCF results will not provide
2 a cost of equity indication that corresponds with the results of the other methods/models.
3 Although I have not ignored the DCF results, I am recommending less reliance on DCF in
4 this case.

6 NATURAL GAS RISK FACTORS

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

8 A: The new competitive, regulatory and economic risks facing gas utilities are different today
9 than formerly. Market-oriented pricing, open access for gas transportation, and changes in
10 service agreements mean that natural gas utilities have been operating in a more complex
11 environment with time frames for decision-making considerably shortened. Of particular
12 concern for the Company, the recent high prices and volatility in natural gas commodity
13 prices has had a negative impact on its customers. Higher commodity prices mean higher
14 customer bills, as the cost of delivered gas is recovered through the GCA mechanism.
15 Higher and volatile gas costs may result in further declines in average use per existing
16 customer and in fewer new customers selecting natural gas to meet their energy needs. The
17 resulting high gas prices have also had an impact on the amount of and number of
18 delinquent customer accounts.

19 As the competitiveness of the natural gas business increases, the risk also
20 increases. With the availability of customer-owned transportation gas, along with delivery
21 of uncertain volumes to dual-fuel customers, risk will continue to rise as large end users

1 obtain for themselves the range of unbundled service offerings, which are currently
2 available from the interstate pipelines for the local distribution utilities.

3

4 Q: Does the Company face competition in its natural gas business?

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

12

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

14 A: The Company's risk profile is strongly influenced by natural gas sold/delivered to
15 industrial/transportation customers. The throughput to the Company's industrial/-
16 transportation customers represents 69% of total throughput, although this class contains
17 only 108 customers. Indeed, throughput to its ten largest customers represents 38% of total
18 Company throughput. Large volume users, which have traditionally used transportation
19 service, also have the ability to bypass the Company's system. In addition, approximately
20 30% of total system throughput is subject to the threat of bypass. Success in this aspect of
21 the Company's market is subject to the business cycle, the price of alternative energy
22 sources, and pressures from competitors. Moreover, external factors can also influence the

1 Company's throughput to these customers which face competitive pressure on their
2 operations from facilities located outside the Company's service territory.

3
4 Q: Please indicate how its construction program affects the Company's risk profile.

5 A: The Company is faced with the requirement to undertake investments to maintain and
6 upgrade existing facilities in its service territory. To maintain safe and reliable service to
7 existing customers, the Company must invest to upgrade its infrastructure. The
8 rehabilitation of the Company's infrastructure represents a non-revenue producing use of
9 capital. The Company has approximately 540 miles of its distribution mains that are to be
10 replaced pursuant to the accelerated main replacement program. Also, the Company has
11 15,446 of its services that will also be replaced along with its accelerated main replacement
12 program. The Company projects its net construction expenditures will be over \$67.7
13 million during the period 2006-2010. Over this five-year period, these capital expenditures
14 will represent approximately 49% ($\$67.7 \text{ million} \div \139.4 million) of its net utility plant at
15 December 31, 2005.

16
17 Q: Does your cost of equity analysis and recommendation take into account the weather
18 normalization adjustment ("WNA") that has been implemented by the Company?

19 A: Yes. The WNA is intended to separate revenues from variations in sales related to usage
20 caused by variations in year-to-year weather conditions from the "normal" weather
21 assumed in establishing rates in a test year context. My cost of equity analysis that

1 provides an 11.25% rate of return on common equity takes into account the Company's
2 WNA.

3
4 Q: Do the LDCs included in your Gas Group already have tariff mechanisms similar to the
5 WNA and other tariff features designed to stabilize revenues?

6 A: Yes, and therefore my analysis already reflects the impacts of the WNA and other revenue
7 stabilization mechanisms on investor expectations through the use of market-determined
8 models. Seven of the nine companies in my Gas Group already have some form of revenue
9 stabilization mechanism, most of which are related to temperature variations, and one
10 additional company has a rate design intended to mitigate the effect of declining use per
11 customer. As such, the market prices of these companies' common equity reflect the
12 expectations of investors related to a regulatory mechanism that adjust revenues for
13 abnormal weather and other occurrences.

14 Other companies in the Gas Group also have been allowed to implement a variety
15 of mechanisms to deal with issues such as infrastructure rehabilitation, bad debt expenses,
16 and conservation expenditures by the LDCs. The trend in the industry is to stabilize the
17 recovery of fixed costs which are unaffected by usage. The Company's proposed
18 mechanisms are designed to accomplish this.

19
20
21

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

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

21 That is not to say there are no benefits to the proposed WNA and other revenue
22 stabilization mechanisms. Variations in weather can significantly affect customers’ bills
23 and the Company’s cash flow. Fluctuations in bad debt expense from year to year, which

1 may also be driven in part by variations in weather, also affect the Company's cash flow.
2 Therefore, the Company can be expected to realize a short-term benefit of improved or at
3 least more predictable liquidity as a result of implementation of these mechanisms. Indeed,
4 the increased stability of the Company's cash flow would be viewed favorably by the credit
5 rating agencies. These are beneficial impacts which will be most directly manifested at the
6 credit quality level rather than the determination of the Company's cost of equity.

7
8 Q: How should the Commission respond to the issues facing the natural gas utilities and in
9 particular Columbia of Kentucky?

10 A: The Commission should recognize and take into account the heightened competitive
11 environment in the natural gas business in determining the cost of capital for the Company
12 and provide a reasonable opportunity for the Company to actually achieve its cost of
13 capital.

14
15 **FUNDAMENTAL RISK ANALYSIS**

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

18 A: Yes. It is necessary to establish a company's relative risk position within its industry
19 through a fundamental analysis of various quantitative and qualitative factors that bear
20 upon investors' assessment of overall risk. The qualitative factors which bear upon the
21 Company's risk have already been discussed. The quantitative risk analysis follows. The
22 items that influence investors' evaluation of risk and its required returns are described in

1 Appendix C. For this purpose, I have utilized the S&P Public Utilities, an industry-wide
2 proxy consisting of various regulated businesses, and the Gas Group.

3
4 Q: What are the components of the S&P public utilities?

5 A: The S&P Public Utilities is a widely recognized index that is comprised of electric power
6 and natural gas companies. These companies are identified on page 3 of Attachment
7 PRM-4. I have used this group as a broad-based measure of all types of utility companies.

8
9 Q: What criteria did you employ to assemble the Gas Group?

10 A: The Gas Group that I employed in this case includes companies that (i) are engaged in
11 similar business lines, (ii) have publicly-traded common stock, (iii) are included in The
12 Value Line Investment Survey, (iv) have a history of increased dividends over the 2001-
13 2005 period, (v) are not currently the target of a merger or acquisition, and (vii) have at
14 least 70% of their assets represented by regulated operations. The Gas Group members are
15 identified on page 2 of Attachment PRM-3.

16
17 Q: Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of
18 capital?

19 A: Yes. Knowledge of a company's credit quality rating is important because the cost of each
20 type of capital is directly related to the associated risk of the firm. So while a company's
21 credit quality risk is shown directly by the credit rating and yield on its bonds, these
22 relative risk assessments also bear upon the cost of equity. This is because a firm's cost of

1 equity is represented by its borrowing cost plus compensation to recognize the higher risk
2 of an equity investment compared to debt.

3
4 Q: How do the bond ratings compare for the Gas Group and the S&P Public Utilities?

5 A: Presently, the corporate credit rating (“CCR”) for Gas Group is A from Standard and
6 Poor’s Corporation (“S&P”) and the Long Term (“LT”) issuer rating is A3 from Moody’s
7 Investors Services (“Moody’s”). The CCR designation by S&P and LT issuer rating by
8 Moody’s focuses upon the credit quality of the issuer of the debt, rather than upon the debt
9 obligation itself. For the S&P Public Utilities, the average composite rating is BBB+ by
10 S&P and Baa1 by Moody’s. Many of the financial indicators that I will subsequently
11 discuss are considered during the rating process.

12
13 Q: How do the financial data compare for Columbia of Kentucky, the Gas Group, and the S&P
14 Public Utilities?

15 A: The broad categories of financial data that I will discuss are shown on Attachments PRM-
16 2, PRM-3, and PRM-4. The data cover the five-year period 2001-2005. For the purpose of
17 my analysis, I have analyzed the historical results for Columbia of Kentucky, the Gas
18 Group and the S&P Public Utilities. I will highlight the important categories of relative
19 risk as follows:

20 Size. In terms of capitalization, Columbia of Kentucky is very much smaller than
21 the average size of the Gas Group and the S&P Public Utilities. All other things being
22 equal, a smaller company is riskier than a larger company because a given change in

1 revenue and expense has a proportionately greater impact on a small firm. As I will
2 demonstrate later, the size of a firm can impact its cost of equity. This is the case for
3 Columbia of Kentucky and the Gas Group.

4 Market Ratios. Market-based financial ratios provide a partial indication of the
5 investor-required cost of equity. If all other factors are equal, investors will require a
6 higher return on equity for companies that exhibit greater risk, in order to compensate for
7 that risk. That is to say, a firm that investors perceive to have higher risks will experience a
8 lower price per share in relation to expected earnings.¹

9 There are no market ratios available for Columbia of Kentucky because its stock is
10 owned by CEG, which in turn is owned by NiSource. The five-year average price-earnings
11 multiple was fairly similar for the Gas Group and the S&P Public Utilities. The five-year
12 average dividend yield was somewhat higher for the Gas Group, as compared to the S&P
13 Public Utilities. The five-year average market-to-book ratio was higher for the Gas Group,
14 as compared to the S&P Public Utilities.

15 Common Equity Ratio. The level of financial risk is measured by the proportion of
16 long-term debt and other senior capital that is contained in a company's capitalization.
17 Financial risk is also analyzed by comparing common equity ratios (the complement of the
18 ratio of debt and other senior capital). That is to say, a firm with a high common equity
19 ratio has lower financial risk, while a firm with a low common equity ratio has higher
20 financial risk. The five-year average common equity ratios, based on permanent capital,
21 were 65.4% for Columbia of Kentucky, 52.0% for the Gas Group and 39.5% for the S&P

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).

1 Public Utilities. I will discuss the Company's capital structure in a later section of my
2 testimony. The trend in the common equity ratios has been toward more equity for the Gas
3 Group.

4 Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned
5 returns signifies relative levels of risk, as shown by the coefficient of variation (standard
6 deviation ÷ mean) of the rate of return on book common equity. The higher the
7 coefficients of variation, the greater degree of variability. For the five-year period, the
8 coefficients of variation were 0.240 (3.1% ÷ 12.9%) for Columbia of Kentucky, 0.057
9 (0.7% ÷ 12.3%) for the Gas Group, and 0.231 (2.5% ÷ 10.8%) for the S&P Public Utilities.
10 The Company's return on equity has been much more variable than the Gas Group.

11 Operating Ratios. I have also compared operating ratios (the percentage of
12 revenues consumed by operating expense, depreciation, and taxes other than income).² The
13 five-year average operating ratios were 88.7% for Columbia of Kentucky, 88.5% for the
14 Gas Group, and 84.6% for the S&P Public Utilities.

15 Coverage. The level of fixed charge coverage (i.e., the multiple by which available
16 earnings cover fixed charges, such as interest expense) provides an indication of the
17 earnings protection for creditors. Higher levels of coverage, and hence earnings protection
18 for fixed charges, are usually associated with superior grades of creditworthiness. The
19 five-year average interest coverage (excluding AFUDC) was 5.01 times for Columbia of
20 Kentucky, 4.00 times for the Gas Group, and 2.68 times for the S&P Public Utilities.

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.

1 Quality of Earnings. Measures of earnings quality usually are revealed by the
2 percentage of Allowance for Funds Used During Construction (“AFUDC”) related to
3 income available for common equity, the effective income tax rate, and other cost deferrals.
4 These measures of earnings quality usually influence a firm’s internally generated funds
5 because poor quality of earnings would not generate high levels of cash flow. Quality of
6 earnings has not been a significant concern for Columbia of Kentucky, the Gas Group, and
7 the S&P Public Utilities.

8 Internally Generated Funds. Internally generated funds (“IGF”) provide an
9 important source of new investment capital for a utility and represent a key measure of
10 credit strength. Historically, the five-year average percentage of IGF to capital
11 expenditures was 115.3% for Columbia of Kentucky, 93.9% for the Gas Group, and
12 109.0% for the S&P Public Utilities.

13 Betas. The financial data that I have been discussing relate primarily to company-
14 specific risks. Market risk for firms with publicly-traded stock is measured by beta
15 coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated
16 with changes in the overall market for common equities.³ Value Line publishes such a
17 statistical measure of a stock’s relative historical volatility to the rest of the market. A
18 comparison of market risk is shown by the Value Line betas provided on page 2 of
19 Attachment PRM-3 -- .79 as the average for the Gas Group, and page 3 of Attachment
20 PRM-4 -- .95 as the average for the S&P Public Utilities. Keeping in mind that the utility
21 industry has changed dramatically during the past five years, the systematic risk percentage

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

1 is 83% ($.79 \div .95$) for the Gas Group using S&P Public Utilities' average beta as a
2 benchmark.

3
4 Q: Please summarize your risk evaluation of Columbia of Kentucky and the Gas Group.

5 A: Columbia of Kentucky is smaller than the average size of the Gas Group and it has much
6 more variable returns. Further, the Company has very substantial construction
7 requirements for the future and its throughput are highly influenced by industrial
8 customers. Overall, the fundamental risk factors indicate that the Gas Group provides a
9 conservative basis for measuring the Company's cost of equity.

10 11 **CAPITAL STRUCTURE RATIOS**

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

13 A: As explained previously, Columbia of Kentucky is wholly-owned by CEG and CEG is a
14 wholly-owned subsidiary of NiSource. In prior cases for Columbia of Kentucky, the
15 capital structure of CEG was used to calculate the Company's weighted average cost of
16 capital. This procedure was followed using generally accepted guidelines for the selection
17 of capital structure ratios, which involve consideration of: (i) the applicant's own
18 capitalization when it issues debt directly in the capital markets, (ii) the use of the parent
19 company's capitalization when the parent company engages in the long-term borrowings
20 on behalf of the applicant, and (iii) the use of hypothetical capital structure ratios when the
21 parent company's capitalization is atypical of the industry in which the applicant does
22 business.

1 Today, NiSource Finance Corporation issues debt directly to outside investors for
2 the benefit of all of the subsidiaries of NiSource, including CEG and Columbia of
3 Kentucky. However, use of the NiSource consolidated capital structure in this case for rate
4 of return purposes creates a number of problems related to debt issued to finance pollution
5 control facilities of NIPSCO, debt issued by non-regulated subsidiaries of NiSource, and
6 significant amounts of capital issued to finance the goodwill related to the acquisition of
7 CEG.

8
9 Q: What approach have you taken in this case to develop capital structure ratios that are
10 appropriate for ratesetting purposes?

11 A: I have analyzed the capital structure issue of Columbia of Kentucky by reference to the
12 capital structure ratios employed by other firms engaged in the gas distribution business,
13 i.e., the Gas Group. I employed the Gas Group capital structure as the foundation for
14 capital structure ratios of Columbia of Kentucky because the capitalization of Columbia of
15 Kentucky is determined by CEG since both the debt and equity of the Company is owned
16 by the parent company.

17
18 Q: Please describe your capital structure proposal.

19 A: For the Columbia of Kentucky, I analyzed the capital structure ratios of the Gas Group to
20 develop reasonable ratios. That data is shown historically on Attachment PRM-3. There,
21 the common equity ratios have been trending upward during the past five years, with the
22 common equity ratio reaching 53.8% at year-end 2005, based upon permanent capital

1 excluding short-term debt. Attachment PRM-3 also shows ratios that include short-term
2 debt. However, those ratios are not useful in this regard because the short-term debt
3 amounts represent the balances at fiscal year end for each company in the Gas Group. For
4 gas companies, short-term debt fluctuates substantially during the year related to seasonal
5 working capital needs associated with customer accounts receivable, which peak during the
6 heating season, and to the financing of stored gas inventory, which accumulates prior to the
7 heating season. As such, short-term debt when it is considered for a gas utility is usually
8 stated on an average basis.

9
10 Q: What capital structure ratios do investors expect for the Gas Group?

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

	Common Equity Ratio		
	2006	2007	2009-11
AGL Resources	49.0%	50.0%	51.5%
Atmos Energy	43.0%	43.0%	45.0%
Laclede Group, Inc.	51.0%	51.0%	52.0%
New Jersey Resources	58.0%	59.0%	63.0%
Nicor, Inc.	64.0%	65.0%	68.0%
Northwest Natural Gas	53.0%	53.0%	53.0%
Piedmont Natural Gas	56.5%	57.5%	58.0%
South Jersey Industries	57.0%	57.0%	60.0%
WGL Resources	59.0%	59.0%	59.0%
Gas Group Average	<u>54.5%</u>	<u>54.9%</u>	<u>56.6%</u>

Source:

The Value Line Investment Survey, September 15, 2006

1

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

6

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

9 A: I have used a 45% long-term debt ratio and a 55% common equity ratio to recast the
10 Company's capitalization. The resulting capital structure is provided on page 1 of
11 Attachment PRM-5. There, I began with the Company's actual per books capitalization at
12 September 30, 2006. I made a pro forma adjustment to reflect the issuance of \$16 million
13 of new long-term debt in November 2006. I then created a hypothetical capital structure
14 consisting of 45% long-term debt and 55% common equity. To that, I recognized the

1 Company's actual thirteen month average of short-term debt to reflect its seasonal cycle.
2 This resulting capital structure for ratesetting purposes is 42.62% long-term debt, 5.30%
3 short-term debt, and 52.09% common equity.
4

5 **COST OF SENIOR CAPITAL**

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

7 A: The determination of the debt cost rate is essentially an arithmetic exercise because the
8 Company has contracted for the use of this capital for a specific period of time at a
9 specified cost rate. Attachment PRM-6 provides the actual embedded cost of long-term
10 debt at September 30, 2006 for Columbia of Kentucky. Since the hypothetical capital
11 structure contains more debt than the actual amount outstanding, I priced the additional
12 hypothetical amount of debt at the rate the Company paid for its recent November 2006
13 new debt issue. I will adopt the 5.69% embedded cost of long-term debt at September 30,
14 2006 using the Columbia of Kentucky hypothetical debt. The cost of short-term debt was
15 taken from Schedule J-C of the Company's Standard Filing Requirements.
16

17 **COST OF EQUITY – GENERAL APPROACH**

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

19 A: Although my fundamental financial analysis provides the required framework to establish
20 the risk relationships between Columbia of Kentucky, the Gas Group, and the S&P Public
21 Utilities, the cost of equity must be measured by standard financial models that I describe
22 in Appendix D. Differences in risk traits, such as size, business diversification,

1 geographical diversity, regulatory policy, financial leverage, and bond ratings must be
2 considered when analyzing the cost of equity.

3 It is also important to reiterate that no one method or model of the cost of equity can
4 be applied in an isolated manner. Rather, informed judgment must be used to take into
5 consideration the relative risk traits of the firm. It is for this reason that I have used more
6 than one method to measure the Company's cost of equity. As noted in Appendix D, and
7 elsewhere in my direct testimony, each of the methods used to measure the cost of equity
8 contains certain incomplete and/or overly restrictive assumptions and constraints that are
9 not optimal. Therefore, I favor considering the results from a variety of methods. In this
10 regard, I applied each of the methods with data taken from the Gas Group and have arrived
11 at a range of cost of equity of 11.25% to 11.75%. From this range, I recommend the
12 11.50% midpoint for Columbia of Kentucky.

13 14 **DISCOUNTED CASH FLOW ANALYSIS**

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

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

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

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

12
13 Q: Please explain the dividend yield component of a DCF analysis.

14 A: The DCF methodology requires the use of an expected dividend yield to establish the
15 investor-required cost of equity. For the twelve months ended October 2006, the monthly
16 dividend yields of the Gas Group are shown graphically on Attachment PRM-7. The
17 monthly dividend yields shown on Attachment PRM-7 reflect an adjustment to the month-
18 end prices to reflect the build up of the dividend in the price that has occurred since the last
19 ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to
20 the dividend payment – usually about two to three weeks prior to the actual payment). An
21 explanation of this adjustment is provided in Appendix E.

1 For the twelve months ending October 2006, the average dividend yield was 4.00%
2 for the Gas Group based upon a calculation using annualized dividend payments and
3 adjusted month-end stock prices. The dividend yields for the more recent six- and three-
4 month periods were 3.90% and 3.82%, respectively. I have used, for the purpose of my
5 direct testimony, a dividend yield of 3.90% for the Gas Group, which represents the six-
6 month average yield. The use of this dividend yield will reflect current capital costs while
7 avoiding spot yields.

8 For the purpose of a DCF calculation, the average dividend yields must be adjusted
9 to reflect the prospective nature of the dividend payments i.e., the higher expected
10 dividends for the future. Recall that the DCF is an expectational model that must reflect
11 investor anticipated cash flows for the Gas Group. I have adjusted the six-month average
12 dividend yield in three different but generally accepted manners, and used the average of
13 the three adjusted values as calculated in Appendix E. That adjusted dividend yield is
14 4.01% for the Gas Group.

15
16 Q: Please explain the underlying factors that influence investor's growth expectations.

17 A: As noted previously, investors are interested principally in the future growth of its
18 investment (i.e., the price per share of the stock). As I explain in Appendix E, future
19 earnings per share growth represents its primary focus because under the constant price-
20 earnings multiple assumption of the DCF model, the price per share of stock will grow at
21 the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of
22 variables can be considered when reaching a consensus of prospective growth. The
23 variables that can be considered include: earnings, dividends, book value, and cash flow

1 stated on a per share basis. Historical values for these variables can be considered, as well
2 as analysts' forecasts that are widely available to investors. A fundamental growth rate
3 analysis can also be formulated, which consists of internal growth (" $b \times r$ "), where " r "
4 represents the expected rate of return on common equity and " b " is the retention rate that
5 consists of the fraction of earnings that are not paid out as dividends. The internal growth
6 rate can be modified to account for sales of new common stock -- this is called external
7 growth (" $s \times v$ "), where " s " represents the new common shares expected to be issued by a
8 firm and " v " represents the value that accrues to existing shareholders from selling stock at
9 a price different from book value. Fundamental growth, which combines internal and
10 external growth, provides an explanation of the factors that cause book value per share to
11 grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book
12 value per share growth.

13 Growth can also be expressed in multiple stages. This expression of growth
14 consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high
15 profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters
16 a "transition" stage where fewer technological advances and increased product saturation
17 begins to reduce the growth rate and profit margins come under pressure. During the
18 "transition" phase, investment opportunities begin to mature, capital requirements decline,
19 and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the
20 mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and
21 return on equity stabilizes at levels where they remain for the life of a firm. The three
22 stages of growth assume a step-down of high initial growth to lower sustainable growth.
23 Even if these three stages of growth can be envisioned for a firm, the third "steady-state"

1 growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic
2 expectation because the three stages of growth can be repeated. That is to say, the stages
3 can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.
4

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

6 A: Investors consider both company-specific variables and overall market sentiment (i.e., level
7 of inflation rates, interest rates, economic conditions, etc.) when balancing their capital
8 gains expectations with its dividend yield requirements. I follow an approach that is not
9 rigidly formatted because investors are not influenced by a single set of company-specific
10 variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth
11 rate indicators using a variety of techniques must be evaluated when formulating a
12 judgment of investor expected growth.
13

14 Q: Before presenting your analysis of the growth rates that apply specifically to the Gas
15 Group, can you provide an overview of the macroeconomic factors that influence investor
16 growth expectations for common stocks?

17 A: Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence
18 stock prices. Forecast growth of the Gross Domestic Product (“GDP”) can represent the
19 starting point for this analysis. The GDP has both “product side” and “income side”
20 components. The product side of the GDP is comprised of: (i) personal consumption
21 expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services;
22 and (iv) government consumption expenditures and gross investment. On the income side

1 of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income;
2 (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments;
3 (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment
4 to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand
5 components) could be used as a long-term representation of revenue growth for public
6 utilities. However, it is well known that revenue growth does not necessarily equal
7 earnings growth. There is no basis to assume that the same growth rate would apply to
8 revenues and all components of the cost of service, especially after the troublesome issues
9 of employees' costs, insurance costs, high fuel costs, and environmental costs are worked-
10 out in the long-term for public utilities. The earnings growth rates for utilities will be
11 substantially affected by fluctuations in operating expenses and capital costs.

12 The long-term consensus forecast that is published semi-annually by the Blue Chip
13 Economic Indicators ("Blue Chip") should be used as the source of macroeconomic
14 growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide
15 variety of economic variables assembled from a panel of more than 50 noted economists
16 from the banking, investment, industrial, and consulting sectors whose advice affects the
17 investment activities of market participants. It is always preferable to use a consensus
18 forecast taken from a large panel of contributors, rather than to rely upon one source that
19 may not be representative of the types of information that have an impact on investor
20 expectations. Indeed, Blue Chip is frequently quoted in The Wall Street Journal, The New
21 York Times, Fortune, Forbes, and Business Week. Twice annually, Blue Chip provides
22 long-range consensus forecasts. Based upon the October 10, 2006 issue of Blue Chip,
23 those forecasts are:

Blue Chip Economic Indicators

Year	Nominal GDP	Corporate Profits, Pretax
2008	5.2%	5.5%
2009	5.3%	5.3%
2010	5.1%	5.5%
2011	5.1%	5.1%
2012	5.1%	5.7%
Averages		
2007-11	5.2%	5.4%
2012-16	5.1%	5.8%

These forecasts show that the rate of growth in corporate profits will decelerate during the first five years of the forecast period. Subsequently, growth will accelerate during the later five years in the period. It is also indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.⁴

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 Attachments PRM-8 and PRM-9. The bar graph provided on Attachment PRM-8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM-8, historical growth in earnings per share was in the range of 4.56% to 6.33% for the Gas Group. Negative growth rates reflected in the historical data provide no reliable guide to gauge investor expected growth for the future. Investor expectations encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics

⁴ Obviously, growth in corporate profits are negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since the 1934.

1 that include negative growth rates should not be given any weight when formulating a
2 composite growth rate expectation. The prospect of rate increases granted by regulators,
3 the continued obligation to provide service as required by customers and the ongoing
4 growth of customers mandate investor expectations of positive future growth rates. Stated
5 simply, there is no reason for investors to expect that a utility will wind up its business and
6 distribute its common equity capital to shareholders, which would be symptomatic of a
7 long-term permanent earnings decline. Although investors have knowledge that negative
8 growth and losses can occur, its expectations include positive growth. Negative historic
9 values will not provide a reasonable representation of future growth expectations because,
10 in the long run, investors will always expect positive growth. Indeed, rational investors
11 expect positive returns, otherwise they will hold cash rather than invest with the
12 expectation of a loss.

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

21 Although five-year forecasts usually receive the most attention in the growth
22 analysis for DCF purposes, present market performance has been strongly influenced by
23 short-term earnings forecasts. Each of the major publications provides earnings forecasts

1 for the current and subsequent year. These short-term earnings forecasts receive prominent
2 coverage, and indeed they dominate these publications. While the DCF model typically
3 focuses upon long-run estimates of earnings, stock prices are clearly influenced by current
4 and near-term earnings forecasts.

5
6 Q: Is a five-year investment horizon associated with the analysts' forecasts consistent with the
7 DCF model?

8 A: Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic
9 assumption. Rather than viewing the DCF in the context of an endless stream of growing
10 dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital
11 appreciation, or capital gains yield) is most relevant to investors' total return expectations.
12 Hence, the sale price of a stock can be viewed as a liquidating dividend that can be
13 discounted along with the annual dividend receipts during the investment-holding period to
14 arrive at the investor expected return. The growth in the price per share will equal the
15 growth in earnings per share absent any change in price-earnings (P-E) multiple -- a
16 necessary assumption of the DCF. As such, my company-specific growth analysis, which
17 focuses principally upon five-year forecasts of earnings per share growth, conforms with
18 the type of analysis that influences the total return expectation of investors. Moreover,
19 academic research focuses on five-year growth rates as they influence stock prices. Indeed,
20 if investors really required forecasts which extended beyond five years in order to properly
21 value common stocks, then I am sure that some investment advisory service would begin
22 publishing that information for individual stocks in order to meet the demands of investors.

1 The absence of such a publication signals that investors do not require infinite forecasts in
2 order to purchase and sell stocks in the marketplace.

3
4 Q: What specific evidence have you considered in the DCF growth analysis?

5 A: As to the five-year forecast growth rates, Attachment PRM-9 indicates that the projected
6 earnings per share growth rates for the Gas Group are 4.46% by IBES/First Call, 4.79% by
7 Zacks, 4.81% by Reuters/Market Guide, and 5.17% by Value Line. The Value Line
8 projections indicate that earnings per share for the Gas Group will grow prospectively at a
9 more rapid rate (i.e., 5.17%) than the dividends per share (i.e., 3.78%), which indicates a
10 declining dividend payout ratio for the future. As indicated earlier, and in Appendix E,
11 with the constant price-earnings multiple assumption of the DCF model, growth for these
12 companies will occur at the higher earnings per share growth rate, thus producing the
13 capital gains yield expected by investors.

14
15 Q: What conclusion have you drawn from these data?

16 A: Although ideally historical and projected earnings per share and dividends per share growth
17 indicators would be used to provide an assessment of investor growth expectations for a
18 firm, the circumstances of the Gas Group mandate that the greater emphasis be placed upon
19 projected earnings per share growth. The massive restructuring of the utility industry
20 suggests that historical evidence alone does not represent a complete measure of growth for
21 these companies. Rather, projections of future earnings growth provide the principal focus
22 of investor expectations. In this regard, it is worthwhile to note that Professor Myron

1 Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best
2 measure of growth in the DCF model is forecasts of earnings per share growth. Hence, to
3 follow Professor Gordon's findings, projections of earnings per share growth, such as those
4 published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represents a
5 reasonable assessment of investor expectations.

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

16 With the repeal of the 1935 Public Utility Holding Company ("PUHC") act, merger
17 and acquisition ("M&A") activity, which already has been prevalent in the utility industry,
18 is expected to accelerate. Acquisitions are usually accomplished at premiums offered to
19 induce stockholders to sell its shares. These premiums create a ripple effect on the stock
20 prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has
21 been a run-up of the stock prices for some utility companies. With these elevated stock
22 prices, dividend yields fall, and without some adjustment to the growth component of the
23 DCF model, the results become unduly depressed by reference to alternative investment

1 opportunities – such as public utility bonds. There are three remedies available to deal with
2 these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the
3 divergence of market capitalization and the book value capitalization, (ii) the use of a
4 growth component in the DCF model which is at the high end of the range, and (iii)
5 supplementing the DCF results with other measures of the cost of equity.

6 The forecasts of earnings per share growth as shown on Attachment PRM-9 provide
7 a range of growth rates of 4.46% to 5.17%. To those company-specific growth rates,
8 consideration must be given to long-term growth in corporate profits. While the DCF
9 growth rates cannot be established solely with a mathematical formulation, it is my opinion
10 that an investor-expected growth rate of 5.00% is within the array of earnings per share
11 growth rates shown by the analysts' forecasts and the forecast growth in overall corporate
12 profits. The Value Line forecast of dividend per share growth is inadequate in this regard
13 due to the forecast decline in the dividend payout that I previously described. As
14 previously indicated, the restructuring and consolidation now taking place in the utility
15 industry will provide additional risks and opportunities as the utility industry successfully
16 adapts to the new business environment. These changes in growth fundamentals will
17 undoubtedly develop beyond the next five years typically considered in the analysts'
18 forecasts that will enhance the growth prospects for the future. As such, a 5.00% growth
19 rate will accommodate all these factors.

20
21 Q: Does the sum of the dividend yield and growth rate provide a complete representation of
22 the cost of equity?

23 A: No.

1 Q: Please explain why.

2 A: As demonstrated in Appendix E, the divergence of stock prices from book values creates a
3 conflict when the results of a market-derived cost of equity are applied to the common
4 equity account measured at book value, which is the measure used in calculating the
5 weighted average cost of capital. This is the situation today where the market price of
6 stock exceeds its book value for most utilities. This divergence of price and book value
7 creates a financial risk difference, whereby the capitalization of a utility measured at its
8 market value contains relatively less debt and more equity than the capitalization measured
9 at its book value.

10 If regulators rely upon the results of the DCF (which are based on the market price
11 of the stock of the companies analyzed) and apply those results to book value, the resulting
12 earnings will not produce the level of required return specified by the model when market
13 prices vary from book value. This is to say, such distortions tend to produce DCF results
14 that understate the cost of equity to the regulated firm when using book values. This
15 shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity
16 upward to make the return consistent with the book value capital structure. The
17 Pennsylvania Public Utility Commission in its Order entered December 22, 2004 involving
18 PPL Electric Utilities Corporation at Docket No. R-00049255 acknowledged that an
19 adjustment to the DCF results was required to make the return consistent with the book
20 value capital structure. In that decision, the Pennsylvania PUC provided PPL (a wires-only
21 electric delivery utility) with an additional 45 basis points to the simple DCF derived cost
22 of equity for the financial risk difference related to the divergence of the market
23 capitalization from the book value capitalization. Similar provisions were made by the

1 Pennsylvania PUC in its decisions dated January 10, 2002 for Pennsylvania-American
2 Water Company at Docket No. R-00016339; dated August 1, 2002 for Philadelphia
3 Suburban Water Company in Docket No. R-00016750; dated January 29, 2004 for
4 Pennsylvania American Water Company at Docket No. R-00038304 (affirmed by the
5 Commonwealth Court on November 8, 2004); and dated August 5, 2004 for Aqua
6 Pennsylvania, Inc. at Docket No. R-00038805. It must be recognized that in order to make
7 the DCF results relevant to the capitalization measured at book value (as is done for rate
8 setting purposes), the market-derived cost rate cannot be used without modification. As I
9 will explain later in my testimony, the DCF model can be modified to account for
10 differences in risk attributed to changes in financial leverage when market prices and book
11 values diverge.

12
13 Q: Is your leverage adjustment dependent upon the market valuation or book valuation from
14 an investor's perspective?

15 A: The only perspective that is important to investors is the return that they can realize on the
16 market value of their investment. As I have measured the DCF, the simple yield (D/P) plus
17 growth (g) provides a return applicable strictly to the price (P) that an investor is willing to
18 pay for a share of stock. The DCF formula is derived from the standard valuation model:
19 $P = D / (k - g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash
20 flows. By rearranging the terms, we obtain the familiar DCF equation: $k = D/P + g$. All of
21 the terms in the DCF equation represent investors' assessment of expected future cash
22 flows that they will receive in relation to the value that they set for a share of stock (P).

23 The need for the leverage adjustment arises when the results of the DCF model (k) are to be

1 applied to a capital structure that is different than indicated by the market price (P). From
2 the market perspective, the financial risk of the Gas Group is accurately measured by the
3 capital structure ratios calculated from the market capitalization of a firm. If the ratesetting
4 process utilizes the market capitalization ratios, then no additional analysis or adjustment
5 would be required, and the simple yield (D/P) plus growth (g) components of the DCF
6 would satisfy the financial risk associated with the market value of the equity
7 capitalization. Since the ratesetting process uses a different set of ratios calculated from the
8 book value capitalization, then further analysis is required to synchronize the financial risk
9 of the book capitalization with the required return on the book value of the equity. This
10 adjustment is developed through precise mathematical calculations, using well recognized
11 analytical procedures that are widely accepted in the financial literature.

12
13 Q: Are there specific factors that influence market-to-book ratios that determine whether the
14 leverage adjustment should be made?

15 A: No. My leverage adjustment is not intended, nor was it designed, to address the reasons
16 that stock prices vary from book value. Hence, any observations concerning market prices
17 relative to book are not on point. My leverage adjustment deals with the issue of financial
18 risk and is not intended to transform the DCF result to a book value return through a
19 market-to-book adjustment.

20 Further, as noted previously, the high market prices of gas utility stocks cannot be
21 attributed solely to the notion that these companies are expected to earn a return on equity
22 that exceeds its cost of equity. Stock prices above book value are common for utility
23 stocks, and indeed non-regulated stock prices exceed book values by even greater margins.

1 In this regard, according to the Barron's issue of November 27, 2006, the major market
2 indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of
3 2.59 times book value which is below the market multiple of other indices. For example,
4 the S&P 500 index trades at 3.09 times book value, the S&P Industrial index is at 3.52
5 times book value, and the Dow Jones Industrial index is at 3.50 times book value. It is
6 difficult to accept that the vast majority of all firms operating in our economy are
7 generating returns far in excess of its cost of capital. Certainly, in our free-market
8 economy, competition should contain such "excesses" if they indeed exist.

9
10 Q: What are the implications of a DCF derived return that is related to market value when the
11 results are applied to the book value of a utility's capitalization?

12 A: The capital structure ratios measured at the utility's book value show more financial
13 leverage, and hence higher risk, than the capitalization measured at its market values.
14 Please refer to Appendix E for the comparison. This means that a market-derived cost of
15 equity, using models such as DCF and CAPM, reflects a level of financial risk that is
16 different from that shown by the book value capitalization. Hence, it is necessary to adjust
17 the market-determined cost of equity upward to reflect the higher financial risk related to
18 the book value capitalization used for ratesetting purposes. Failure to make this
19 modification would result in a mismatch of the lower financial risk related to market value
20 used to measure the cost of equity and the higher financial risk of the book value capital
21 structure used in the ratesetting process. That is to say, the cost of equity for the Gas Group
22 that is related to the 53.98% common equity ratio using book value has higher financial
23 risk than the 67.52% common equity ratio using market values. Because the ratesetting

1 process utilizes the book value capitalization, it is necessary to adjust the market-
2 determined cost of equity for the higher financial risk related to the book value of the
3 capitalization.

4
5 Q: How is the DCF-determined cost of equity adjusted for the financial risk associated with
6 the book value of the capitalization?

7 A: In pioneering work, Nobel laureates Modigliani and Miller developed several theories
8 about the role of leverage in a firm's capital structure. As part of that work, Modigliani and
9 Miller established that as the borrowing of a firm increases, the expected return on
10 stockholders' equity also increases. This principle is incorporated into my leverage
11 adjustment which recognizes that the expected return on equity increases to reflect the
12 increased risk associated with the higher financial leverage shown by the book value capital
13 structure, as compared to the market value capital structure that contains lower financial
14 risk. Modigliani and Miller proposed several approaches to quantify the equity return
15 associated with various degrees of debt leverage in a firm's capital structure. These
16 formulas point toward an increase in the equity return associated with the higher financial
17 risk of the book value capital structure. As detailed in Appendix E, the Modigliani and
18 Miller theory shows that the cost of equity increases by 0.51% (9.52% - 9.01%) when the
19 book value of equity, rather than the market value of equity, is used for ratesetting
20 purposes.

21

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

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

13

14 Q: What DCF cost rate have you calculated?

15 A: The resulting DCF cost rate is:

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

Gas Group 4.01% + 5.00% + 0.51% = 9.52% x 1.02 = 9.71%

16

17 As indicated by the DCF result shown above, the flotation cost adjustment adds 0.19%
18 (9.71% - 9.52%) to the rate of return on common equity for the Gas Group. In my opinion,
19 this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown
20 above represents the simplified (i.e., Gordon) form of the model that contains a constant
21 growth assumption. I should reiterate, however, that the DCF indicated cost rate provides

1 an explanation of the rate of return on common stock market prices without regard to the
2 prospect of a change in the price-earnings multiple. An assumption that there will be no
3 change in the price-earnings multiple is not supported by the realities of the equity market
4 because price-earnings multiples do not remain constant.

5 6 RISK PREMIUM ANALYSIS

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

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

12
13 Q: What long-term public utility debt cost rate did you use in your risk premium analysis?

14 A: In my opinion, a 6.25% yield represents a reasonable estimate of the prospective yield on
15 long-term A-rated public utility bonds. As I will subsequently show, the Moody's index
16 and the Blue Chip forecasts support this figure.

17 The historical yields for long-term public utility debt are shown graphically on page
18 1 of Attachment PRM-11. For the twelve months ended September 2006, the average
19 monthly yield on Moody's A-rated index of public utility bonds was 6.06%. For the six
20 and three-month periods ending September 2006, the yields were 6.28% and 6.19%,
21 respectively.

1 Q: What factors have influenced recent interest rates?

2 A: The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market
3 Committee ("FOMC") policy, which is now in transition. In the two year period between
4 June 2004 and June 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis
5 point increments. These policy actions, which have brought the Fed Funds rate to 5.25%,
6 are widely interpreted as part of the process of moving toward a more neutral range for
7 monetary policy. Current interest rates are characterized by a relatively flat yield to
8 slightly inverted curve.

9

10 Q: What forecasts of interest rates have you considered in your analysis?

11 A: I have determined the prospective yield on A-rated public utility debt by using the Blue
12 Chip along with the spread in the yields that I describe above and in Appendix G. The
13 Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest
14 rates compiled from a panel of banking, brokerage, and investment advisory services. In
15 early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility
16 bonds because the Federal Reserve deleted these yields from its Statistical Release H.15.
17 To independently project a forecast of the yields on A-rated public utility bonds, I have
18 combined the forecast yields on long-term Treasury bonds published on October 1, 2006,
19 and the yield spread of 1.00% that I describe in Appendix G and Attachment PRM-8. For

1 comparative purposes, I have also shown the Blue Chip of Aaa-rated and Baa-rated corporate
 2 bonds. These forecasts are:

Blue Chip Financial Forecasts						
Year	Quarter	Corporate		30-Year	A-rated Public Utility	
		Aaa-rated	Baa-rated	Treasury	Spread	Yield
2006	Fourth	5.7%	6.6%	4.9%	1.0%	5.9%
2007	First	5.8%	6.7%	5.0%	1.0%	6.0%
2007	Second	5.9%	6.8%	5.0%	1.0%	6.0%
2007	Third	5.9%	6.8%	5.0%	1.0%	6.0%
2007	Fourth	5.9%	6.8%	5.1%	1.0%	6.1%
2008	First	6.0%	6.9%	5.1%	1.0%	6.1%

3
4
5

6 Q: Are there additional forecasts of interest rates that extend beyond those shown above?

7 A: Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1,
 8 2006 publication, the Blue Chip published forecasts of interest rates are reported to be:

Blue Chip Financial Forecasts						
Averages	Corporate		30-Year	A-rated Public Utility		
	Aaa-rated	Baa-rated	Treasury	Spread	Yield	
2007-11	6.3%	7.2%	5.4%	1.0%	6.4%	
2012-16	6.5%	7.3%	5.6%	1.0%	6.6%	

9

10 Given these forecast interest rates, a 6.25% yield on A-rated public utility bonds represents
 11 a reasonable expectation.

12

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

14 A: Appendix H provides a discussion of the financial returns that I relied upon to develop the
 15 appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity
 16 risk premium by comparing the market returns on utility stocks and the market returns on

1 utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market
2 returns for utility stocks because it is intended to represent firms engaged in regulated
3 activities and today is comprised of electric companies and gas companies. The S&P
4 Public Utility index is more closely aligned with these groups than some broader market
5 indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset
6 of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the
7 role of judgment in establishing the risk premium for public utilities. With the equity risk
8 premiums developed for the S&P Public Utilities as a base, I derived the equity risk
9 premium for the Gas Group.

10
11 Q: What equity risk premium for the S&P Public Utilities have you determined for this case?

12 A: To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities
13 by averaging (i) the midpoint of the range shown by the geometric mean and median and
14 (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive
15 way of measuring the central tendency of the historical returns. As shown by the values set
16 forth on page 2 of Attachment PRM-12, the indicated risk premiums for the various time
17 periods analyzed are 5.17% (1928-2005), 6.05% (1952-2005), 5.19% (1974-2005), and
18 5.20% (1979-2005). The selection of the shorter periods taken from the entire historical
19 series is designed to provide a risk premium that conforms more nearly to present
20 investment fundamentals and removes some of the more distant data from the analysis.

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

3 A: Yes. First, the terminal year of my analysis presented in Attachment PRM-12 represents
4 the returns realized through 2005. Second, the selection of the initial year of each period
5 was based upon the events that I described in Appendix H. These events were fixed in
6 history and cannot be manipulated as later financial data becomes available. That is to say,
7 using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as
8 the beginning point for the measurement period regardless of the financial results that
9 subsequently occurred. Likewise, 1974 represented a benchmark year because it followed
10 the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the
11 deregulation of the financial markets. As such, additional data are merely added to the
12 earlier results when they become available, clearly showing that the periods chosen were
13 not driven by the desired results of the study.

14
15

16 Q: What conclusions have you drawn from these data?

17 A: Using the summary values provided on page 2 of Attachment PRM-12, the 1928-2005
18 period provides the lowest indicated risk premium, while the 1952-2005 period provides
19 the highest risk premium for the S&P Public Utilities. Within these bounds, a common
20 equity risk premium of 5.20% ($5.19\% + 5.20\% = 10.39\% \div 2$) is shown from data covering
21 the periods 1974-2005 and 1979-2005. Therefore, 5.20% represents a reasonable risk
22 premium for the S&P Public Utilities in this case. As noted earlier in my fundamental risk
23 analysis, differences in risk characteristics must be taken into account when applying the

1 results for the S&P Public Utilities to the Gas Group. I recognized these differences in the
 2 development of the equity risk premium in this case. I previously enumerated various
 3 differences in fundamentals between the Gas Group and the S&P Public Utilities, including
 4 size, market ratios, common equity ratio, return on book equity, operating ratios, coverage,
 5 quality of earnings, internally generated funds, and betas. In my opinion, these differences
 6 indicate that 5.00% represents a reasonable common equity risk premium in this case. This
 7 represents approximately 96% ($5.00\% \div 5.20\% = 0.96$) of the risk premium of the S&P
 8 Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public
 9 Utilities.

10
 11 Q: What common equity cost rate would be appropriate using this equity risk premium and the
 12 yield on long-term public utility debt?

13 A: The cost of equity (i.e., “k”) is represented by the sum of the prospective yield for long-
 14 term public utility debt (i.e., “i”) and the equity risk premium (i.e., “RP”). To that cost
 15 must be added an adjustment for common stock financing costs (“flot.”). The Risk
 16 Premium approach provides a cost of equity of:

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

17 Gas Group 6.25% + 5.00% = 11.25% + 0.19% = 11.44%

CAPITAL ASSET PRICING MODEL

1
2 Q: How have you used the Capital Asset Pricing Model to measure the cost of equity in this
3 case?

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

9
10 Q: What are the features of the CAPM as you have used it?

11 A: The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return
12 premium that is proportional to the systematic risk of an investment. The details of my use
13 of the CAPM and evidence in support of my conclusions are set forth in Appendix I. To
14 compute the cost of equity with the CAPM, three components are necessary: a risk-free
15 rate of return (“Rf”), the beta measure of systematic risk (“ β ”), and the market risk
16 premium (“ $R_m - R_f$ ”) derived from the total return on the market of equities reduced by the
17 risk-free rate of return. The CAPM specifically accounts for differences in systematic risk
18 (i.e., market risk as measured by the beta) between an individual firm or group of firms and
19 the entire market of equities. As such, to calculate the CAPM it is necessary to employ
20 firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas
21 Group. In contrast, my Risk Premium approach also considers industry- and company-
22 specific factors because it is not limited to measuring just systematic risk. As a
23 consequence, the Risk Premium approach is more comprehensive than the CAPM. In

1 addition, the Risk Premium approach provides a better measure of the cost of equity
2 because it is founded upon the yields on corporate bonds rather than Treasury bonds.

3

4 Q: What betas have you considered in the CAPM?

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

7

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

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

$$15 \quad \beta_l = \beta_u [1 + (1 - t) D/E + P/E]$$

16 where β_l = the leveraged beta, β_u = the unleveraged beta, t = income tax rate, D = debt
17 ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by
18 Value Line have been calculated with the market price of stock and therefore are related to
19 the market value capitalization. By using the formula shown above and the capital
20 structure ratios measured at its market values, the beta would become .64 for the Gas
21 Group if it employed no leverage and was 100% equity financed. With the unleveraged

1 beta as a base, I calculated the leveraged beta of 1.00 for the Gas Group associated with
2 book value capital structure.

3
4 Q: What risk-free rate have you used in the CAPM?

5 A: For reasons explained in Appendix G, I have employed the yields on 20-year Treasury
6 bonds using both historical and forecast data to match the longer-term horizon associated
7 with the ratesetting process. As shown on pages 2 and 3 of Attachment PRM-13, I
8 provided the historical yields on Treasury notes and bonds. For the twelve months ended
9 September 2006, the average yield was 4.98%, as shown on page 3 of that schedule. For
10 the six- and three-months ended September 2006, the yields on 20-year Treasury bonds
11 were 5.19% and 5.09%, respectively. As shown on page 4 of Attachment PRM-11,
12 forecasts published by Blue Chip on October 1, 2006 indicate that the yields on long-term
13 Treasury bonds are expected to be in the range of 4.9% to 5.1% during the next six
14 quarters. The longer term forecasts described previously show that the yields on Treasury
15 bonds will average 5.4% from 2007 through 2011 and 5.6% from 2012 to 2016. For
16 reasons explained previously, forecasts of interest rates should be emphasized at this time.
17 Hence, I have used a 5.25% risk-free rate of return for CAPM purposes.

18
19 Q: What market premium have you used in the CAPM?

20 A: As developed in Appendix I, the market premium is developed by averaging historical
21 market performance (i.e., 6.5%) and the forecasts (i.e., 6.69%). For the historically based
22 market premium, I have used the arithmetic mean. I am aware that the Commission has

1 expressed its preference for considering both the arithmetic mean and the geometric mean.
2 So if that approach is to be taken, much more weight should be placed on the arithmetic
3 mean because it is the correct measure in the single-period model specification of the
4 CAPM. The resulting market premium is 6.60% ($6.5\% + 6.69\% = 13.19\% \div 2$), which
5 represents the average market premium using historical and forecast data.

6
7 Q: Are there adjustments to the CAPM results that are necessary to fully reflect the rate of
8 return on common equity?

9 A: Yes. The technical literature supports an adjustment relating to the size of the company or
10 portfolio for which the calculation is performed. There would be an understatement of a
11 firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say,
12 as the size of a firm decreases, its risk, and hence its required return increases. Moreover,
13 in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms
14 have higher capital costs than otherwise similar larger firms (see *Fundamentals of Financial*
15 *Management*, fifth edition, page 623). Also, the Fama/French study (see "The Cross-
16 Section of Expected Stock Returns"; *The Journal of Finance*, June 1992) established that
17 size of a firm helps explain stock returns. In an October 15, 1995 article in *Public Utility*
18 *Fortnightly*, entitled "Equity and the Small-Stock Effect," it was demonstrated that the
19 CAPM could understate the cost of equity significantly according to a company's size.
20 Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower
21 deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In
22 this regard, Gas Group has an average market capitalization of its equity of \$1,538 million,
23 which would make them a mid-cap portfolio according to the size of the companies traded

1 on the NYSE, AMEX, and NASDAQ. The mid-cap market capitalization would indicate a
2 size premium of 1.02% for the Gas Group. Absent such an adjustment, the CAPM would
3 understate the required return. My size adjustment is very conservative because the market
4 capitalization of Columbia of Kentucky by itself would be smaller than the mid-cap
5 category described above and, therefore, is entitled to a larger size premium than I have
6 used.

7
8 Q: What CAPM result have you determined using the CAPM?

9 A: Using the 5.25% risk-free rate of return, the leverage adjusted beta of 1.00 for the Gas
10 Group, the 6.60% market premium, and the flotation cost adjustment developed previously,
11 the following result is indicated.

$$R_f + \beta \times (R_m - R_f) + size = k + flot. = K$$

Gas Group 5.25% + 1.00 x (6.60%) + 1.02% = 12.87% + 0.19% = 13.06%

12 13 14 COMPARABLE EARNINGS APPROACH

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

16 A: The technical aspects of my Comparable Earnings approach are set forth in Appendix J. In
17 order to identify the appropriate return on equity for a public utility, it is necessary to
18 analyze returns experienced by other firms within the context of the Comparable Earnings
19 standard. The firms selected for the Comparable Earnings approach should be companies
20 whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that

1 circularity is avoided. To avoid circularity, it is essential that returns achieved under
2 regulation not provide the basis for a regulated return. Because regulated firms must
3 compete with non-regulated firms in the capital markets, it is appropriate to view the
4 returns experienced by firms which operate in competitive markets. One must keep in
5 mind that the rates of return for non-regulated firms represent results on book value
6 actually achieved, or expected to be achieved, because the starting point of the calculation
7 is the actual experience of companies that are not subject to rate regulation. Counsel
8 advises me that the United States Supreme Court has held that:

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

20
21 Therefore, it is important to identify the returns earned by firms that compete for
22 capital with a public utility. This can be accomplished by analyzing the returns of non-
23 regulated firms that are subject to the competitive forces of the marketplace.

24 There are two avenues available to implement the Comparable Earnings approach.
25 One method would involve the selection of another industry (or industries) with
26 comparable risks to the public utility in question, and the results for all companies within
27 that industry would serve as a benchmark. The second approach requires the selection of
28 parameters that represent similar risk traits for the public utility and the comparable risk
29 companies. Using this approach, the business lines of the comparable companies become

1 unimportant. The latter approach is preferable with the further qualification that the
2 comparable risk companies exclude regulated firms. As such, this approach to Comparable
3 Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book
4 ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived
5 from non-regulated companies that are subject to competition in the marketplace and not
6 rate regulation. Since regulation is a substitute for competitively-determined prices, the
7 returns realized by non-regulated firms with comparable risks to a public utility provide
8 useful insight into a fair rate of return. This is because returns realized by non-regulated
9 firms have become increasingly relevant in the context of a market that provides more
10 investment alternatives. Moreover, the rate of return for a regulated public utility must be
11 competitive with returns available on investments in other enterprises having
12 corresponding risks, especially in a more global economy.

13 To identify the comparable risk companies, the Value Line Investment Survey for
14 Windows was used to screen for firms of comparable risks. The Value Line Investment
15 Survey for Windows includes data on approximately 1700 firms. Excluded from the
16 selection process were companies incorporated in foreign countries and master limited
17 partnerships (MLPs).

18
19 Q: How have you implemented the Comparable Earnings approach?

20 A: In order to implement the Comparable Earnings approach, non-regulated companies were
21 selected from the Value Line Investment Survey for Windows that have six categories (see
22 Appendix J for definitions) of comparability designed to reflect the risk of the Gas Group.
23 These screening criteria were based upon the range as defined by the rankings of the

1 companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank,
2 Financial Strength, Price Stability, Value Line betas, and Technical Rank. The specific
3 companies comprising the Comparable Earnings group and its associated rankings within
4 the ranges are identified on page 1 of Attachment PRM-12.

5 Value Line data was relied upon because it provides a comprehensive basis for
6 evaluating the risks of the comparable firms. As to the returns calculated by Value Line for
7 these companies, there is some downward bias in the figures shown on page 2 of
8 Attachment PRM-12 because Value Line computes the returns on year-end rather than
9 average book value. If average book values had been employed, the rates of return would
10 have been slightly higher. Nevertheless, these are the returns considered by investors when
11 taking positions in these stocks. Finally, because many of the comparability factors, as
12 well as the published returns, are used by investors for selecting stocks, and to the extent
13 that investors rely on the Value Line service to gauge its returns, it is, therefore, an
14 appropriate database for measuring comparable return opportunities.

15
16 Q: What data have you used in your Comparable Earnings analysis?

17 A: I have used both historical realized returns and forecast returns for non-utility companies.
18 As noted previously, I have not used returns for utility companies so as to avoid the
19 circularity that arises from using regulatory influenced returns to determine a regulated
20 return. It is appropriate to consider a relatively long measurement period in the
21 Comparable Earnings approach in order to cover conditions over an entire business cycle.
22 A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average
23 business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings

1 method can be applied directly to the book value capitalization because the nature of the
2 analysis relates to book value. Hence, Comparable Earnings does not contain the potential
3 misspecification contained in market models when the market capitalization and book
4 value capitalization diverge significantly. The historical rate of return on book common
5 equity was 14.1% using the median value as shown on page 2 of Attachment PRM-14. The
6 forecast rates of return as published by Value Line are shown by the 14.5% median values
7 also provided on page 2 of Attachment PRM-14.

8
9 Q: What rate of return on common equity have you determined in this case using the
10 Comparable Earnings approach?

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

	<u>Historical</u>	<u>Forecast</u>	<u>Average</u>
Comparable Earnings Group	14.10%	14.50%	14.30%

12
13
14 **CONCLUSION ON COST OF EQUITY**

15 Q: What is your conclusion concerning the Company's cost of common equity?

16 A: Based upon the application of a variety of methods and models described previously, it is
17 my opinion that the reasonable range cost of common equity is 11.25% to 11.75%. From
18 this range, I propose an 11.50% rate of return on common equity for the Company. It is
19 essential that the Commission employ a variety of techniques to measure the Company's
20 cost of equity because of the limitations/infirmities that are inherent in each method.