COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF COLUMBIA GAS	)	CASE NO. 2013-00167
OF KENTUCKY, INC.	)	

VOLUME 9

DIRECT TESTIMONY

Columbia Gas of Kentucky, Inc.
Case 2013-00167
Table of Contents
Volume 9

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of)
Columbia Gas of Kentucky, Inc.) Case No. 2013-00167

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

Stephen B. Seiple, Asst. General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com
Richard Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF HERBERT A. MILLER, JR.

Q: Please state your name and business address.

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

Q: What is your current position and responsibilities?

A: Since September 1, 2006, I have served as President of Columbia Gas of Kentucky, Inc. ("Columbia" or "Company") and a member of its Board of Directors. My responsibilities include the general operation of the business of the natural gas distribution utility in 30 Kentucky counties and specifically all regulatory and legislative affairs, business strategy, policy matters, customer relations and external and public matters associated with the utility service of Columbia.

Q: What is your educational background?

A. I received a B.A. degree from the University of Kentucky in 1972 and a J.D. degree from the University of Kentucky College of Law in 1976.

Q: Please describe your employment history.

A: Prior to joining Columbia, from 1998 to 2006, I served as the Corporate Counsel for all of the regulated subsidiaries of the American Water Works Company in Kentucky, Tennessee and Georgia. From 1993 to 1998, I was a partner in the law firm of Stoll Keenon & Park (now Stoll Keenon Ogden). From 1980 to 1993, I was the Senior Vice President and General Counsel for First Security Corporation, a Kentucky multi-bank holding company. From 1977 to 1980, I was Corporate Counsel for the Lexington-Fayette Urban County Government and from 1976 to 1977 I served in the Office of Chief Counsel of the U.S. Customs Service in Washington, D.C.

Q. Have you previously testified before the Kentucky Public Service Commission?

A: Yes. I have filed testimony in several previous cases including Case Nos. 2007-00008 ("2007 Rate Case") and 2009-0041 ("2009 Rate Case), and in the pending Columbia proceeding before this Commission in Case No. 2013–00066 regarding the application for approval of the corporate realignment and transfer of ownership of stock in Columbia.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to summarize the issues presented by Columbia in this case. I will also introduce the other witnesses who will present testimony on Columbia's behalf.

Q: Please summarize the business of Columbia.

A: Columbia is one of seven natural gas local distribution companies in the NiSource family of utility companies. Headquartered in Lexington, Kentucky, it employs over 120 active full-time employees and serves more than 135,000 customers in 30 Kentucky counties. Through approximately 2,600 miles of mains, it serves residential, commercial and industrial customers in the counties that include the municipalities of Ashland, Cynthiana, Frankfort, Georgetown, Greenup, Hindman, Inez, Irvine, Lexington, Louisa, Maysville, Mt. Sterling, Paris, South Shore, Versailles and Winchester.

NiSource Inc. is headquartered in Merrillville, Indiana and was created by the merger of Northern Indiana Public Service Company ("NIPSCO") and Bay State Gas Company in 1998 and the Columbia Energy Group in 2000. NiSource is a registered public utility subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

NiSource has three primary business units: electric generation and distribution, natural gas transmission and storage and natural gas distribution. Columbia is part of the natural gas distribution business unit.

Q: In summary, what is Columbia requesting in this case?

A: Columbia is seeking a revenue increase of approximately $16,595,000, or 17.75% in order to produce rates that are fair, just and reasonable for both the Company and its customers. This requested revenue increase is necessary for Columbia to continue to provide safe and reliable service at the lowest reasonable price to its customers.

Columbia is proposing that the Commission adopt several important regulatory changes, including : (1) the approval of Columbia's use of a forecasted test period for ratemaking purposes; (2) as contemplated in Case No. 2009-00141, the inclusion (or "rolling in") of the current AMRP charge for its Accelerated Main Replacement Program into the monthly customer charge, and the enhancement of the AMRP program based on recovery of this capital on a forecasted test year basis; (3) a proposed rate design that will adjust the base rates for Columbia's residential customer classes GSR and SVGTS GSR on a quarterly basis to reconcile the difference in non-gas revenue to account for changes in gas usage per customer caused by factors not addressed by the existing Weather Normalization Adjustment; (4) approval to continue its pilot CHOICE program for an additional three years with changes that reflect the need for more transparency and clarity as revealed in Columbia's 2012 customer survey; and, (5) a recognition of Columbia's intent to continue, in a separate proceeding, the continuation of its demand-side management ("DSM") program, based on input received from the DSM Collaborative Group. All of the initiatives and concepts referenced above will be summarized and supported by other Columbia witnesses in this proceeding and I refer you to their testimony for further details.

Q: What test period has Columbia used to develop its revenue requirement?

A: Columbia developed the revenue requirement using a forecasted test period, consisting of the 12 months ended December 31, 2014.

Q: When were Columbia's rates last approved by the Commission?

A: Columbia's current rates were approved by this Commission on October 26, 2009, in its 2009 Rate Case. The rates established in that proceeding were intended to produce an overall return of 8.10%, based on a return on equity of 10.50%.

Q: Since its last rate case in 2009, has Columbia been able to achieve the level of its authorized rates of return?

A: No. As described in the testimony of Columbia witness Feingold, Columbia's rates of return on equity ("ROE") achieved each year have been less than its authorized rates of return. The actual returns on equity for Columbia for years 2006 through 2012 are shown in a chart prepared by witness Feingold and range from a low of 5.28% in 2006 to a high of 9.22% in 2011. Columbia's ROE in 2012 was 6.16%.

Q: What factors have contributed to Columbia's inability to earn the authorized rates of return?

A: This inability is primarily related to several factors. The first factor is what is referred to as "regulatory lag." This is the financial impact due to the elapsed time between the investment or deployment of capital, the filing of a petition for recovery of the investment and the actual recovery of the return on the capital invested. For Columbia, the elapsed time includes the time period between rate case proceedings as well as the time between the investment of AMRP capital and the recovery of the AMRP charge, which may be as long as 17 months. A second reason is the impact of the non-gas revenue loss from customers leaving its system due to reasons such as the inability to pay, fuel-switching to other energy sources and relocations outside of its service territory. A third significant reason is the decline in the average use of natural gas by Columbia customers. The decline in usage is addressed in more detail below and in the testimony of Columbia witnesses Gresham and Feingold. The financial impact to Columbia from usage declines has long-term implications for Columbia because of the efforts of customers to conserve energy, install more efficient gas appliances, better insulate their homes and businesses and adopt business processes that use less natural gas. Columbia's proposal to address this decline is usage is found in the rate design changes sponsored by Columbia witness Feingold.

Q: What returns are necessary to provide Columbia the opportunity to earn a reasonable return on investment used and useful in providing service to customers?

A: Columbia proposes an overall rate of return of 8.59% and an ROE of 11.25%. These returns are fully supported in the direct testimony of Columbia witness Moul.

Q: Has Columbia made efforts since its last rate case to improve customer service?

A: Yes. Columbia has continued to organize its operations more efficiently and continues to implement procedures to improve service while managing costs. Many of the improvements outlined in Case No. 2009-00141 are now part of our normal operations: computerized customer scheduling and emergency response management, installation of mobile data terminals ("MDTs") in all service vehicles to direct and redirect service responses, the adoption of "call ahead" procedures to reduce the Company's CGI ("can't get in" orders) and improved customer relations. Columbia has improved customer payment options by increasing the number of methods for customers to pay bills electronically and has added many more remote payment locations. Now, customers may pay their bills at Kentucky Kroger stores, Wal-Marts and other locations throughout our service territory.

Q: Have the efforts you just described proven successful in improving customer satisfaction?

A: Yes. Since the last rate case, Columbia has focused on several key metrics to measure the level of satisfaction of its customers who interact with our Company. Columbia uses the Louisville-based market research firm of Thoroughbred Research Group to measure customer satisfaction through random telephone interviews of customers who have interacted with our customer call center. In 2012, survey results showed that 96% of customers responding expressed overall customer satisfaction with their experience with Columbia, 80% said that they were able to complete their interaction by only using one phone call and 92% approved of the ease of doing business with Columbia. These results are ahead of our customer service goals and represent a continuing upward annual trend since the last rate case. Additionally, Columbia participates in quarterly surveys by J.D. Power & Associates. Although it is the smallest of the survey participants, Columbia continues to rank favorably among Kentucky gas distribution companies in the survey from an overall customer satisfaction perspective. Lastly, Columbia considers the number of customer complaints brought to the Public Service Commission an important measurement tool in how it is serving its customers. In 2011 and 2012, the number of informal complaints to the Public Service Commission fell to near record lows.

Q: Has Columbia improved safety and reliability for its employees and customers since it last rate proceeding?

A: Yes, safety for customers, the public and our own employees is a paramount priority for Columbia. Columbia has invested, and will continue to invest, its financial resources and its management attention in developing programs, designing work activities and measuring results for improved safety. Due to increased, focused maintenance efforts and replacement of Columbia lines, the number of "leaks per mile" has fallen from 0.22 in 2009 to 0.11 in 2012. The OSHA recordable injury rate for its employees has fallen from 3.07 in 2009 to 1.46 in 2012 and the DART rate (Days Away, Restricted or Transferred) has dropped over the same period from 2.41 to 0.71. Both statistics are well below 2012 industry averages of 3.25 and 2.02, respectively. Further, Columbia is acting to protect the public by continually inspecting, monitoring, repairing and replacing (where necessary) its facilities. A priority focus for Columbia is the importance of its Distribution Integrity Management Plan ("DIMP"). Included in the forecasted revenue requirement (see the testimony of Columbia witness Katko) are enhancements for public safety, including the addition of a GIS Mapping Technician, a pipeline safety Compliance Specialist and an additional Damage Prevention Coordinator who will work with excavators, contractors, public officials and customers to help prevent damages caused by others hitting gas lines during construction projects and other excavations. This is one of Columbia's biggest risks to it system's integrity and increased focus will occur on this going forward.

Q: What is Columbia doing to improve efficiencies in its business operations?

A: Columbia strives to build business efficiencies both into its capital and operations and maintenance ("O&M") planning. As stated in the testimony of Columbia witness Belle, Columbia has targeted its AMRP implementation process with the benefit of computer assistance combined with employee experience to target areas of our pipeline system for main replacement and avoid the increased costs of merely reacting to unplanned discoveries of priority pipe. Columbia also works closely with state road officials, municipalities and counties to identify upcoming construction projects and road paving plans to coordinate projects and avoid costly duplication of efforts. Columbia has also developed improved cost-saving and time-saving response processes for employee scheduling and calling out its service employees for installations, repairs and emergencies.

Columbia recognizes that efficiencies can be gained from improved efforts to read its customer meters every month. Since 2009, Columbia has installed automated meter reading ("AMR") devices on its "hard to reach" meters that would otherwise slow down the meter reading process, and in homes and businesses where it is difficult to access the meter (sometimes referred to as "can't get in" or CGI locations). Columbia has also begun to add AMR devices to the meters it is installing as part of its meter replacement program. A key improvement in business efficiency will occur in 2014 when Columbia plans to install AMR devices throughout its service territory on all gas meters. The capital costs associated with this effort are approximately $7 million. However, once all the devices are installed by the end of 2014 and meter reading routes adjusted, cost reductions will be realized for Columbia customers which savings have been included in Columbia's revenue requirement in this case.

Q: What is Columbia's accelerated main replacement program ("AMRP").

A: In 2008, Columbia began the process of identifying and replacing the unprotected gas pipelines in it system. By unprotected, I mean pipelines and related facilities without, or with inadequate, cathodic protection and susceptible to corrosion. As described in the 2009 Rate Case and in testimony in this case by Columbia witness Belle, this program had an initial goal of complete replacement of such pipe over a 30-year period. In the 2009 Rate Case, and as authorized by KRS § 278.509, a recovery mechanism based on a historical spend on a per customer bill basis was approved for the costs associated with replacing this pipe. Since 2008, approximately 400,000 feet of this "priority" pipe and associated services have been replaced.

Q: How is the AMRP customer charge affected by the proposed rates in this proceeding?

A: Each year, Columbia submits a report on the progress of its AMRP program, the types and amounts of pipe replaced, the amount of capital invested and the proposed monthly customer charge proposed for the recovery of the invested capital in the preceding calendar year. To date, the amount of accumulated monthly charge approved by the Commission is $1.06 per residential customer. As originally contemplated in this approved program, the amount of this charge is proposed to be "rolled in" to Columbia's proposed base rates and the AMRP charge will be re-set to zero.

Q: Is Columbia proposing to change this recovery mechanism?

A: Yes. In order to reduce the regulatory lag between the time of investment and the time of recovery, Columbia is proposing to change its AMRP recovery from a historical test period basis to a forecasted test period methodology. Currently, an AMRP investment can occur early in one calendar year and not be eligible for recovery until the middle of the following calendar year, creating a recovery lag of up to 17 months. The proposed recovery methodology would allow for such investment to be recovered more quickly and encourage Columbia to continue its aggressive replacement program. Please refer to the testimony of Columbia witness Belle for additional details on the AMRP program and Columbia witness Cooper on the recovery mechanism.

Q: What is Columbia's experience with accuracy and execution in the implementation of its capital program?

A: As reflected in the testimony of Columbia witness Belle, Columbia's experience in meeting and exceeding its capital budget over the past five years has been excellent and very supportive of a strong capital investment program. Witness Belle has indicated that, with the implementation of the

Company's AMRP over the past five years, Columbia has experienced a positive variance to its plan by approximately 8.2%.

Q: **What is Columbia proposing with regard to the application of capital construction budget "slippage"?**

A: Columbia recognizes that the Commission has used the concept of "slippage" when allowing recovery of projected capital construction costs as a percentage of its proposed capital budgets. The application of "slippage" is designed to create a sense of internal budget discipline to avoid customer rates that are based on aggressive forecasted construction budgets that are not regularly met. In this case, Columbia is requesting that the "slippage" applied to the capital budgets be based on a five-year average of a positive 8.2% rather than a ten-year average. The reason for this request is the recognition that Columbia's capital construction budget contains a materially large component of AMRP construction, a program that only began five years ago and now has a planned life of at least two more decades. In the past five years, Columbia's capital program has become a disciplined, computer assisted, focused process of planning and execution. Columbia intends to use this process throughout 2014 and beyond. Although Columbia recognizes that the Commission has used a "slippage" factor, both positively and negatively, of 10 years with at least one other utility, Columbia respectfully requests that, under these circumstances, any new application of "slippage" as applied to Columbia, recognize the current and future state of the strength of Columbia's capital program and apply a five year average for a slippage factor.

Q: **What primary factors are contributing to Columbia's revenue deficiency?**

A: Since 2009, Columbia has continued to invest to serve its customers in Kentucky. At the same time, Columbia has absorbed increased costs for labor, employee benefits, materials, supplies, and other general operating and maintenance expenses, and is projected to continue do so over the forecasted period. Columbia will have increased its rate base from $166,208,000 at December 31, 2008 to a forecasted 13-month average at December 31, 2014 of $203,298,000, an increase of over 22%.

Additionally, as explained in the testimony of Columbia witness Gresham, Columbia has experienced declines in both the number of its residential customers and in the average gas usage per residential customer. From 2008 to 2012 the number of residential customers has declined 2.6% from 123,724 to 120,446. Over the same period, the number of commercial customers declined 2.7% from 14,359 to 13,966. The decline in the usage of gas per customer is addressed in the question and response below.

Q: How has the decline in residential gas usage impacted Columbia's revenue deficiency?

A: We understand the decline in annual weather normalized usage for residential heating customers is a phenomenon being experienced by a number of natural gas distribution companies, including Columbia: Columbia's average annual use per residential customer in 1999 was 88.4 thousand cubic feet ("Mcf"). In 2009, it was 70.3 Mcf. By the close of 2012, it had fallen to 66.9 Mcf per year; a decline of 24% from 1999 and 5% from 2009. As indicated by Columbia witness Gresham, this trend is expected to continue in the forecasted test period. All classes of customers are expected to continue to seek ways to reduce gas consumption through the use of more efficient appliances, implementing changes in construction practices, having better weatherized homes and businesses and implementing improved and more efficient commercial and industrial processes. In addition, some of Columbia's commercial and industrial customers are those in automotive manufacturing and supply, steel production, oil refining, glass production and other general manufacturing businesses, all of which are seeking ways to reduce energy usage, including natural gas. These changes and adjustments are generally considered beyond the result of changing climate conditions or swings in natural gas commodity prices and could directly impact Columbia's ability to continue to meet its service obligation to its customers.

Q: How does Columbia's proposed revenue normalization adjustment mechanism affect the rates proposed in this proceeding?

A: Columbia's Revenue Normalization Adjustment ("RNA") mechanism will adjust the base rates for its residential rate classes GSR and SVGTS GSR, as proposed in this proceeding, on a quarterly basis to reconcile the difference in normalized non-gas revenue to account for changes in gas usage per customer caused by factors not addressed by the existing WNA Clause. Please refer to the testimony of Columbia witnesses Feingold and Cooper for details on the purposed, structure and operation of the proposed Revenue Normalization Adjustment ("RNA") mechanism.

Q: How was Columbia's revenue requirement identified?

A: Generally speaking, a revenue requirement is the amount of revenue a utility needs, or is projected to need, to cover its operating expenses, pay debt service and provide a fair return to common equity investors. For Columbia, this will be supported in detail by Columbia witness Katko.

Q: Why are the proposed rates necessary to eliminate the revenue deficiency referenced above?

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

Q: Will the rates for the gas commodity section on a customer's bill be affected by the proposed rate changes?

A: No, the proposed rate changes will not affect a customer's gas commodity charges. The variable gas supply commodity cost can be at least 50% of a customer's bill depending on the commodity cost of natural gas. The charge for gas supply costs (billed for usage on a Mcf basis) will continue to be adjusted, subject to Commission approval, on a quarterly basis, without any markup by Columbia, and will not be impacted by the proposed rate changes in this proceeding.

Q: What portion of the customer's bill will be affected?

A: The proposed rate adjustment will affect the Customer Charge, Delivery Charge, and the riders as indicated in this proceeding. These charges are based on Columbia's costs of making gas available to customers, including main installations, line inspections, repair and maintenance, customer service, personnel, emergency responses and other operational expenses.

Q: How will the current residential Customer Charge and Delivery Charge be affected by this case?

A: As previously contemplated in Case No. 2009–00141, the current AMRP rider will be rolled in to the base rates for each class of customers covered by the AMRP rider and the rider will be re-set to zero. This accumulated amount since Columbia's last rate case is $1.06 per month for residential customers. The rates designed to address the revenue requirement will be added to the monthly Customer Charge resulting in an increase from $12.35 to $18.50 per month for residential customers (including the AMRP roll-in) and the Gas Delivery Charge will be increased from its current level of $1.8715 per Mcf to $2.4322 per Mcf for residential customers.

Q: **At the effective date of the proposed rates, how will Columbia's overall residential rates be impacted?**

A: While the actual impact to a specific residential customer's total bill will depend on the volume of gas used by that particular customer, under the proposed rates, including the re-set of the AMRP charge, a residential customer using an annual average of 66 Mcf, will experience, in the 2014 forecasted test period, a monthly increase of $7.98, or 17.1% in overall rates.

Q: **The Commission's Order in Administrative Case No. 2008-00408 dated October 6, 2011 requires Columbia to provide its most current energy efficiency policy and respond to appropriate interrogatories related to the policy. How will Columbia address its current DSM program?**

A: Columbia's current DSM program was established in the 2009 rate case. The program consists of a three-part effort to provide home energy check-ups (audits), rebates for high efficiency appliances and a program with the Community Action Council for low-income customers to replace failing gas furnaces with high efficiency gas furnaces.

The Program initially experienced a slow start-up but has since experienced increasing demand for the services provided. Columbia will seek the input of the DSM Collaborative Group and file a separate application regarding the program's future prior to the current expiration date.

Q: What will happen to the component of Columbia's DSM cost recovery mechanism that makes an adjustment for lost revenue from customers using the program?

A: The DSM cost recovery mechanism that adjusts for lost revenue from customers using the program is the Energy Efficiency/Conservation Program Revenue from Lost Sales component. The calculation of Columbia's proposed RNA will capture the lost revenue due to reductions in usage from customers participating in Columbia's DSM program and non-participants. In order to avoid "double-recovery" of this lost revenue, the RNA will replace the Revenue from Lost Sales component of Columbia's Energy Efficiency and Conservation Program Cost Recovery. Please refer to the testimony of Columbia witness Cooper for specific details.

Q: What is the Columbia CHOICE program?

A: The CHOICE program is referred to in Columbia's tariff as the Small Volume Gas Transportation Service ("SVGTS") and has been in existence as a pilot program since 2000. The program expires during the forecasted test period on March 31, 2014. Under the program, Columbia customers may enroll as CHOICE customers and purchase their gas commodity from a registered gas marketer rather than Columbia. There are more than 29,000 Columbia customers currently enrolled as CHOICE customers, which is almost 25% of Columbia's total eligible customers. Columbia files annual reports with the Commission showing the results of customers participating in the CHOICE program.

Q: Is Columbia proposing an extension in the CHOICE program?

A: Yes. Columbia is proposing an extension of three additional years with changes in the program to address issues of clarity and transparency identified in a customer survey conducted in 2012 which revealed that, while many customers desire the ability to choose their gas supplier, many do not know whether they are CHOICE customers and whether they have saved any money by being a participant. To respond to these survey findings, Columbia proposes to: (1) continue the program but with a new provision of an annual disclosure to CHOICE customers of the existence and basic terms of the between the customer and the CHOICE marketer; and, (2) provide an opportunity for all customers to more easily compare CHOICE gas commodity rates and make informed choices whether to stay in the program or return to the Columbia gas commodity rate. Questions regarding the CHOICE program should be addressed to Columbia witness Cooper.

Q. **Will Columbia continue to support its energy assistance programs for its low income customers?**

A: Yes, Columbia's shareholders, customers and employees will continue to support several different forms of energy assistance programs, including Wintercare and the Energy Assistance Program ("EAP") that are administered by the Community Action Council. NiSource shareholders also contribute annually to help low-income families throughout Columbia's service territory to help pay their gas heating bills. This amount includes the assistance programs of the EAP, Wintercare and the Lexington Black Church Coalition.

Q: **Do Columbia shareholders support community charitable agencies?**

A: Yes. During 2012, our shareholders contributed more than $125,000 to charitable causes. The level of this amount is expected to continue into the future and is not a part of the revenue requirement for Columbia and Columbia is not seeking recovery of those expenses in base rates.

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

A: Other Columbia witnesses providing direct testimony are:

* Judy M. Cooper, Director of Regulatory Affairs, who will address Columbia's proposals that include tariff revisions, the RNA provision, AMRP recovery, and the CHOICE program;

* Eric T. Belle, Manager of Field Engineering for Columbia, who will provide an overview of Columbia's infrastructure system, the AMRP process, AMR devices, the capital budgeting process and Columbia's performance in the execution of its capital plan over the past five years;

* William Gresham, Manager of Forecasting for NiSource Corporate Services Company, who will provide support for the forecasted test period basis of customer usage, additions, and trends in natural gas usage.

* Paul R. Moul, Managing Consultant of P. Moul & Associates, who will present evidence regarding Columbia's cost of capital and recommend the appropriate rates of return for Columbia;

* Russell Feingold, Vice President of Black & Veatch Corporation, who will support the class cost of services studies prepared by Columbia for the forecasted period, its class revenue proposal, evaluate the impact of declining customer usage and present evidence for the proposed revenue normalization adjustment, as well as for Columbia's other rate design proposals;

* S. Mark Katko, Manager of Regulatory Strategy and Support for NiSource Corporate Services Company, who will describe and support the forecasted test period for Columbia, including the Columbia budgeting process, and the revenue requirement proposed by Columbia;

* Chad E. Notestone, Lead Regulatory Analyst for NiSource Corporate Services Company, who will provide evidence to support the rate base as forecasted by Columbia, as well as revenue based on customer bills and volumes, in the forecasted test period;

* John J. Spanos, a Senior Vice-President with the Valuation and Rate Division of Gannett-Fleming, Inc., who will sponsor the depreciation study performed for Columbia in this proceeding;

* Susan M. Taylor, CPA, the Controller of NiSource Corporate Services Company ("NCSC"), who will provide a background of how NCSC supports Columbia and support for the basis for the annualized level of NCSC charges for Columbia;

* Panpilas W. Fischer, CPA, Manager of Corporate Income tax for NiSource Corporate Services Company, who will provide testimony to support the level of federal and state income taxes included in the cost of service for Columbia.

Q: **Does this complete your Prepared Direct testimony?**

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Herbert A. Miller, Jr. being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Herbert A. Miller, Jr.

COMMONWEALTH OF KENTUCKY

COUNTY OF FAYETTE

SUBSCRIBED AND SWORN to before me by Herbert A. Miller, Jr. on this the 25 day of May, 2013.

Notary Public

My Commission expires: 04/09/2016

EMILY L. WILLIAMS
Notary Public
462579 State at Large
Kentucky
My Commission Expires Apr 9, 2016

Columbia Exhibit No. _______

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

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

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

Richard S. Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com
Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF JUDY M. COOPER

Q: Please state your name and business address.

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

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

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

Q: What is your educational background?

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

Q: What is your employment history?

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

Q. Have you previously testified before the Kentucky Public Service Commission?

A: Yes, I have testified before the Kentucky Public Service Commission in four cases for Columbia. Case No. 2002-00117, "The Filing by Columbia Gas of Kentucky, Inc. to Require that Marketers in the Small Volume Gas Transportation Program be Required to Accept a Mandatory Assignment of Capacity," Case No. 2007-00008, "In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.," Case No. 2009-00141, "In the matter of an adjustment of rates of Columbia Gas of Kentucky, Inc.," and Case No. 2010-00146, "An Investigation of Natural Gas Retail Competition Programs."

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

A: The purpose of my testimony is to support certain exhibits required by the Commission's regulations including the proposed modifications to Columbia's tariff pages set forth in Schedule L according to 807 KAR 5:001 Section 16(1)(b)4 and 807 KAR 5:001 Section 16(1)(b)5b. In addition, my testimony will address: (1) the proposed modifications to Columbia's Accelerated Main Replacement Program Rider ("AMRP"); (2) the new Revenue Normalization Adjustment ("RNA") Rider which is proposed to implement the new RNA adjustment mechanism presented by Columbia witness Feingold; (3) the proposed revision to Columbia's Energy Efficiency and Conservation Rider to implement the proposed Revenue Normalization Adjustment presented by Mr. Feingold; and, (4) the continuation of Columbia's pilot Customer CHOICE program and Columbia's associated gas transportation programs. The new and revised proposed tariff sheets are filed according to the recent revisions to 807 KAR 5:011.

Q: **What are the tariff changes that Columbia has included in Schedule L?**

A: The changes proposed on Tariff Sheet Nos. 1 and 3 are to correct page number references in the Table of Contents. The proposed changes on Tariff Sheet Nos. 5, 6, 7, 11, 14, 22, 31, and 38 are base rate changes. These changes are supported by the revenue requirement contained in the testimony of Columbia witness Katko and the rate design contained in the testimony of Columbia witness Feingold.

The change on Tariff Sheet No. 8 is to update the list of counties that Columbia serves. Changes on Tariff Sheet Nos. 1, 12 and 31 add the proposed RNA Rider.

On Tariff Sheet No. 12 there is also a correction to a page number. Tariff Sheet Nos. 30, 33, and 36 are revised to extend the time period for service by changing the date. Tariff Sheet No. 51d is revised to amend the Revenue from Lost Sales, a change necessitated by Columbia's proposed RNA Rider. Tariff Sheet No. 51i is added as a new page that sets out the proposed RNA Rider described in the testimony of Columbia witness Feingold. Tariff Sheets 80, 80a, and 82a are simply better quality images of Columbia's sample bills.

<u>Accelerated Main Replacement Program Rider</u>

Q: What is the purpose of the proposed revision to Rider AMRP set forth on Tariff Sheet No. 58?

A: The purpose of the proposed revisions in Rider AMRP is: (1) to reflect the roll-in of the current AMRP charges to proposed base rates; (2) to reduce the regulatory lag in recovery of eligible costs; and, (3) to update the revenue requirement calculation to include property taxes associated with AMRP-related investments.

Q: What are the proposed charges for Rider AMRP?

A: Consistent with the intentions expressed in Case No. 2009-00141 wherein the Commission first approved Columbia's Rider AMRP, Columbia's currently effective AMRP charges will be "rolled-in" to base rates at the conclusion of this proceeding and the AMRP charge reset to zero as of the effective date for rates authorized in this case. The proposed Rider AMRP charges that would become effective for January 2014 are $0.00 per billing period for all rate schedules.

Q: How do the proposed revisions address the regulatory lag that you mentioned?

A: The proposed revisions will convert the calculation of the AMRP charge from a 12-month historical basis to a 12-month forecast of projected costs thus reducing the regulatory lag, or the period of time between cost incurrence and recovery. A subsequent reconciliation would adjust for any difference between forecasted and actual costs. The current AMRP charge is based upon costs incurred through December 31, 2011.[1] Because Columbia has utilized a forecasted test period in its application, forecasted additions

[1] Columbia's Accelerated Main Replacement Program Annual Filing, Case No. 2013-00087, that adjusts for AMRP activity through December 31, 2012 is pending before the Commission.

through the end of the rate period are included in the revenue requirements and proposed base rates in this case.

Q: Do the proposed base rates include all forecasted AMRP additions through the end of the rate year 2014?

A: No, the additions are only partially included in the proposed base rates because the forecasted test period uses a 13-month average of 2014 spend instead of the actual projected AMRP spend in 2014.

Q: How does Columbia propose to address subsequent revisions to Rider AMRP charges?

A: Subsequent revisions to Rider AMRP charges would follow the requirements set forth in the tariff, except that there would not be a filing on March 31, 2014. The first filing subsequent to the conclusion of this case would be submitted on October 15, 2014 to update the projected AMRP program costs for calendar year 2015 and establish the charge to be effective January 2015. Columbia proposes to also incorporate in the filing, AMRP eligible costs not included in its base rates as approved in this case. The AMRP cost of service not in base rates would be the difference between the projected calendar year 2014 AMRP spend and the 13 month average included in base rates. Filings subsequent to 2014 would also be made by October 15 of each year with the revised charge to be effective the following January.

Q: What are the updates to the AMRP revenue calculation that Columbia proposes?

A: Columbia proposes to update the revenue requirement calculation on Tariff Sheet 58 to include property taxes related to the AMRP.

Q: Does Columbia's current Rider AMRP revenue requirement calculation include property taxes?

A: No, property taxes related to the AMRP are not enumerated as an eligible cost in Columbia's currently authorized Rider AMRP on Sheet No. 58 of its tariff. The revenue requirement calculation set forth in Rider AMRP was approved by the Commission in Case No. 2009-00141, by Order dated October 26, 2009. A part of the calculation was envisioned to determine the change in operating expenses associated with AMRP related investments. The only change enumerated was depreciation expense.

Q: Should Columbia's Rider AMRP revenue requirement calculation include property taxes?

A: Yes. Columbia has come to realize that the change in property taxes, or ad valorem taxes, should also have been enumerated so as to be included in the revenue requirement calculation. Like depreciation, property taxes are a change in operating expenses associated with AMRP related investments and should be included in the calculation of Rider AMRP revenue requirement.

Q: How does Columbia propose to determine the change in property taxes to be included?

A: The change in property taxes will be inserted in Columbia's AMRP filing formats under the Operating Expenses caption.

Q: Has the Commission approved similar riders and mechanisms for other natural gas utilities?

A: Yes. Similar riders utilizing a forecasted plan of plant replacements and a subsequent true-up for actual costs, that include property taxes have been approved by the Commission for LG&E in Case No. 2012-00222 by Order dated December 20, 2012; for Delta Natural Gas in Case No. 2010-00116 by

Order dated October 21, 2012, and for Atmos Energy Corporation in Case No. 2009-00354 by Order dated May 28, 2010. Unlike Columbia's currently authorized mechanism which is purely an historical adjustment, all of the other approved mechanisms utilize forecasted and true-up adjustments, and were approved by the Commission subsequent to Columbia's current mechanism. The mechanisms of Delta and Atmos specifically include property taxes in the list of items included in the calculation of the revenue requirement. LG&E does not specifically enumerate property taxes or specifically include a reduction for savings in its revenue requirement calculation. Rather, LG&E includes, "Incremental Operation and Maintenance" in the calculation of its revenue requirement.

Revenue Normalization Adjustment Rider

Q: What is the Revenue Normalization Adjustment Rider?

A: The RNA Rider is the tariff mechanism to implement the RNA presented by Columbia witness Feingold. It is set forth on Columbia's proposed new Tariff Sheet No. 51i.

Q: How will the RNA Rider operate?

A: The RNA Rider will operate much like Columbia's existing tariff mechanisms that provide for periodic rate adjustments such as its Gas Cost Adjustment Clause, Energy Efficiency and Conservation Rider and Rider AMRP. It provides for a periodic recalculation of the RNA Billing Factor according to the provisions set forth in the proposed tariff on Sheet No. 51i.

Q: How will the RNA Billing Factor be applied to customer bills?

A: The RNA Billing Factor will be applied to the base rate Delivery Charge for residential customers because both amounts are volumetric charges. The amount shown on the customer bill as the line item "Gas Delivery Charge" is currently a calculation based on customer usage and the volumetric Delivery Charge applied to the customer's applicable usage for the billing period. Columbia proposes to apply the RNA Billing Factor to the volumetric Delivery Charge and maintain the current calculation and presentation of the "Gas Delivery Charge" on the customer bill.

Q: Is there another tariff change resulting from the addition of the proposed Revenue Normalization Adjustment?

A: Yes, the Energy Efficiency and Conservation Rider should be revised. Upon implementation of the RNA and absent a change to the calculation of the Energy Efficiency/Conservation Program Recovery Component, specifically the Revenue from Lost Sales component, a possible double-counting of lost sales could occur. In order to avoid possible double-counting, Columbia proposes to set the Energy Efficiency Conservation Program Revenue from Lost Sales component to a zero amount in the months that would be subject to the RNA. This change is shown on Sheet No. 51d of Columbia's tariff.

Gas Transportation and Customer CHOICE

Q: What types of gas transportation service does Columbia provide?

A: Columbia offers transportation service to residential, commercial and industrial customers. Columbia's tariffs for transportation services originated with the advent of natural gas transportation in the 1980s. The transportation market and customers utilizing transportation services have evolved significantly in the last thirty years. Over the years, Columbia has made tariff changes to address some of that evolution, an example being the introduction of the Customer CHOICE(SM) program in 2000. Columbia's transportation services are set forth on Tariff Sheet Nos. 30 through 41, in its Rates Schedules Small Volume Gas Transportation Service ("SVGTS"), Small Volumes Aggregation Service ("SVAS"), Delivery Service ("DS"), and Main Line Delivery Service ("MLDS"). Rates Schedules SVGTS and SVAS constitute Columbia' Customer CHOICE program ("CHOICE"). Transportation pursuant to Rate Schedules DS and MLDS is commonly referred to as "traditional transportation" service.

Q: Did Columbia consider the findings of the Commission's Order in Case No. 2010-00146 dated December 28, 2010 in determining the changes to its gas transportation programs?

A: Yes. Administrative Case No. 2010-00146, was established by the Commission to address House Joint Resolution 141 ("HJR141"), passed by the Kentucky General Assembly in its 2010 Regular Session. HJR141 directed the Commission to investigate natural gas retail competition programs and submit a written report of its findings to the Legislative Research Commission. The written report of the Commission was contained in its Order of December 28, 2010.

The Commission's report described the existing transportation services of the five largest LDCs in Kentucky, including Columbia's traditional transportation and CHOICE programs. The volume thresholds vary among the five LDCs for the availability of transportation services. As stated in the report, Columbia is the only Kentucky LDC that has proposed and been approved to make transportation service available to any customer, regardless of size, who desires to choose a third-party supplier (marketer). Columbia's CHOICE transportation service is available to any customer using less than 25,000 Mcf per year. Traditional transportation service is available for large-volume customers, those using a minimum of 25,000 Mcf per year. In its report, the Commission stated, "In any competition program, whether voluntary or mandatory, we find it important that the LDCs remain in the merchant function and that customers retain the ability to receive service from their LDC,"[2]. The Commission concluded its report by stating that it would evaluate each LDC's tariffs and rate design in each LDC's next general rate proceeding.

Q: **What changes to its gas transportation services does Columbia propose?**

A: Columbia proposes to extend its CHOICE pilot program through March 31, 2017, and to utilize the extension of the program to address the insights identified in Case No. 2012-00132.[3] Columbia believes its existing

[2] Case No. 2010-00146, Order dated December 28, 2010, page 23.

[3] Columbia Gas of Kentucky, Inc. Filing of Customer Choice Survey Results, Order dated February 8, 2013.

transportation thresholds are appropriately established within the context of its distribution system for the maintenance of system integrity and reliability to customers. While entirely optional, the combination of transportation services that Columbia offers provides all customers the opportunity to purchase their gas supply from an alternative supplier while Columbia remains in the merchant function and the supplier of last resort. No other changes are proposed to Columbia's gas transportation services.

Q: Why has Columbia proposed to extend the term of its CHOICE program?

A: Columbia's CHOICE pilot program was extended through March 31, 2014, in Case No. 2010-00233 by Order dated February 3, 2011. In its Order approving the extension, the Commission directed that a survey be created regarding the CHOICE program and that the survey be a collaborative effort involving Columbia, Commission Staff, the Attorney General of the Commonwealth of Kentucky, interested stakeholders including CHOICE program marketers, and consumer group representatives. The expiration date of the extension falls within the rate year of the forecasted test year utilized in Columbia's application.

Q: Has the survey regarding the CHOICE program been created?

A: Yes, The survey questions were prepared through the collective efforts of Columbia, Commission Staff, representatives of the Office of the Attorney General, marketers participating in Columbia's CHOICE Program, and customer groups, as directed in Case No. 2010-00233. The survey was completed and results were filed with the Commission in Case No. 2012-00132. By Order dated February 8, 2013, the Commission closed the case and found that any further evaluation of and discovery regarding the CHOICE program should occur in Columbia's next application for approval to extend the program beyond March 31, 2014.

Q: What were the insights identified from the CHOICE survey?

A: An analysis of the survey results identified customer awareness of participation and misperceptions about CHOICE and perceived merits as issues that should be further researched.

Q: How does Columbia propose to address the issues during the proposed extension of the CHOICE program?

A: Columbia will utilize the extension of the pilot program to develop additional means of disclosure to its customers about the CHOICE program, how to make informed decisions about participation and how to identify themselves as a participant in the program. Columbia is currently considering an annual disclosure to participants either by Columbia or the customer's chosen marketer so that customers are more aware of their participation status. Columbia is also considering improvements to awareness of resources available to customers that explain the CHOICE program and tools for evaluating participation so it is easier for customers to make price and other comparisons. In addition, as Columbia indicated in Case No. 2010-00146, the Commission's role in oversight of marketer participation is another area where improvements may be considered.

Q: Has the Commission required any information be provided for consideration of an extension of the CHOICE program?

A: Yes, the Commission's Order dated February 3, 2011 in Case No. 2010-00233 approving the extension of the program through March 31, 2013 required that in its next filing for an extension of the CHOICE program, Columbia should include details sufficient to show its calculation of its customers' savings/losses as a result of participation in the CHOICE program from April 1, 2011 through March 31, 2013. The information is attached as Attachment JMC-1.

Q: Why does Columbia seek to extend its CHOICE program when the comparison of customer savings/losses does not seem to be improving?

A: Continuation of the CHOICE program is not based on whether participants in the aggregate have or have not saved money. An individual customer may or may not have saved money and whether or not that savings is material to the customer, is the individual opinion of the customer. While it might seem surprising, the results of the recently completed CHOICE survey found that customers are highly satisfied yet, perceptions are muddled and that consumers need to be better informed about the options available to them for the CHOICE program to be evaluated on its own merits[4]. This is why Columbia has proposed to extend the program.

Q: Does this complete your Prepared Direct testimony?

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

[4] Columbia Gas of Kentucky, Inc., Customer CHOICE Survey Final Report, page 8.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Judy M. Cooper, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Judy M Cooper
Judy M. Cooper

COMMONWEALTH OF KENTUCKY

COUNTY OF FAYETTE

SUBSCRIBED AND SWORN to before me by Judy M. Cooper on this the 23rd day of May, 2013.

Evelyn Long Dunn
Notary Public # 419232

My Commission expires: 5/15/2014

Columbia Gas of Kentucky, Inc.
CHOICE Results

Month	**CHOICE Volumes** MCF	**Marketer Billing** $	**SVGTS ACA** $		**Columbia** **GCA per MCF**	**Comparison** (b * e)	**Savings** (f) - ((c)+(d))
(a)	(b)	(c)	(d)		(e)	(f)	(g)
April 2011	381,415.0	2,653,186.40	(68,435.46)	$	5.8813	2,243,216.04	**(341,534.90)**
May	196,739.4	1,435,963.20	(34,485.48)	$	5.8813	1,157,083.43	**(244,394.29)**
June	106,655.4	786,405.19	(18,363.21)	$	5.4551	581,815.87	**(186,226.11)**
July	90,382.0	693,470.90	(9,320.96)	$	5.4551	493,042.85	**(191,107.09)**
August	61,421.5	451,224.36	(7,649.39)	$	5.4551	335,060.42	**(108,514.55)**
September	85,854.1	635,456.35	(6,417.93)	$	5.6418	484,371.66	**(144,666.76)**
October	122,390.4	925,622.68	(9,917.12)	$	5.6418	690,502.16	**(225,203.40)**
November	271,211.9	2,051,249.02	(23,993.20)	$	5.6418	1,530,123.30	**(497,132.52)**
December	471,428.1	3,536,420.50	(48,152.11)	$	5.4498	2,569,188.86	**(919,079.53)**
January 2012	696,261.6	5,033,190.82	(72,388.53)	$	5.4498	3,794,486.47	**(1,166,315.82)**
February	644,111.9	4,559,343.74	(52,387.17)	$	5.4498	3,510,281.03	**(996,675.54)**
March	473,183.2	3,303,951.22	(11,384.41)	$	5.6509	2,673,910.94	**(618,655.87)**
April	202,587.1	1,381,195.64	(1,445.12)	$	5.6509	1,144,799.44	**(234,951.08)**
May	157,450.0	1,036,439.38	(1,539.56)	$	5.6509	889,734.21	**(145,165.62)**
June	100,075.3	644,686.58	(1,020.01)	$	3.7230	372,580.34	**(271,086.23)**
July	77,278.5	479,045.60	(572.34)	$	3.7230	287,707.86	**(190,765.40)**
August	75,014.7	470,490.04	(708.73)	$	3.7230	279,279.73	**(190,501.58)**
September	91,842.2	568,710.85	(14,788.46)	$	3.5459	325,663.26	**(228,259.13)**
October	118,164.1	741,937.38	(20,196.43)	$	3.5459	418,998.08	**(302,742.87)**
November	307,659.6	2,035,036.57	(40,314.34)	$	3.5459	1,090,930.18	**(903,792.05)**
December	486,548.8	3,217,612.96	(45,244.00)	$	4.2366	2,061,312.65	**(1,111,056.31)**
January 2013	723,800.9	4,807,695.74	(48,179.38)	$	4.2366	3,066,454.89	**(1,693,061.47)**
February	718,213.5	4,747,938.50	(47,368.46)	$	4.2366	3,042,783.31	**(1,657,786.73)**
March	651,065.9	4,283,858.43	(51,538.25)	$	4.1237	2,684,800.45	**(1,547,519.73)**

Columbia Exhibit No._____

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF ERIC T. BELLE ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

<u>**PREPARED DIRECT TESTIMONY OF ERIC T. BELLE**</u>

Q: Please state your name and business address.

A: My name is Eric T. Belle and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

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

A: I am the Manager of Field Engineering for Columbia Gas of Kentucky, Inc. ("Columbia") and Columbia Gas of Ohio, Inc. As Manager, Field Engineering, my principal responsibilities include overseeing the identification, design, and estimating of generally all capital work for Columbia's gas distribution system. I am also responsible for the development, monitoring, and execution of Columbia's capital budget. I provide leadership and strategic direction to the Field Engineering staff in line with Columbia's goals. I also provide technical guidance and support to Columbia's engineering staff in support of their professional development and the accomplishment of department objectives. I facilitate and encourage the improvement of existing engineering processes, policies and procedures. I monitor and evaluate the performance of Columbia's infrastructure replacement program and collaborate with peers to ensure effective execution of the program.

Q: What is your educational background?

A. I have a Bachelor of Science degree in Chemical Engineering from Syracuse University, Syracuse, New York and a Master's degree in Business Administration from Tiffin University, Tiffin, Ohio.

Q: What is your employment history?

A: In 1995, I began my career in Toledo, Ohio with Columbia as an Operations Engineering Trainee where I gained a broad understanding of the natural gas distribution industry. In 1997, I accepted a position as an Operations Engineer in Findlay, Ohio. As an Operations Engineer, I was responsible for evaluating, planning and designing natural gas distribution facilities. I also provided technical assistance and support to the construction and field operations staff involved in the construction, operation, and maintenance of gas distribution facilities. In 2006, I was promoted to Field Engineering Leader where I was responsible for providing technical and budgetary guidance, support, and direction to Columbia's Field Engineering department in northwest Ohio. Additionally, I ensured all projects in northwest Ohio were designed according to all applicable codes and regulations. In 2009, I was promoted to my current position of Manager, Field Engineering for Columbia.

Q. Have you previously testified before any regulatory commissions?

A: I have testified before the Public Utilities Commission of Ohio.

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

A: The purpose of my testimony is to provide a general overview of Columbia's operating territory, gas distribution system, the capital budgeting process, the Accelerated Main Replacement Program ("AMRP") and Columbia's plans for its Automated Meter Reading program ("AMR"). I explain the engineering and management practices of Columbia as they relate to the execution of the AMRP and the overall capital program. I discuss Columbia's performance with respect to its overall goal of accelerating the replacement of its age infrastructure. I also discuss Columbia's performance in execution its capital budget over the last five years with focus on the success in minimizing the variance between budgeted versus actual capital spend. I also sponsor Filing Requirements 12-b, 12-f and 12-g.

COLUMBIA'S OPERATING TERRITORY AND GAS DISTRIBUTION SYSTEM

Q: What geographic area does Columbia serve?

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

Q: Please describe Columbia's gas distribution system.

A: Columbia Gas of Kentucky was incorporated in 1958 from consolidations of many companies over a period of time. The companies include Central Kentucky Natural Gas, Lexington Gas Company, Huntington Gas Company, Frankfort Kentucky Natural Gas Company, United Fuel Gas Company, Inland Gas Company, and Limestone Gas. As a result of these consolidations, Columbia's distribution system consists of many independent systems and various types of pipe. As of March 31, 2013, Columbia operates approximately 2,562 miles of distribution mains which are comprised of 435 miles of bare steel main, 828 miles of cathodically protected coated steel main, 20 miles of cast iron and wrought iron main, 1,274, miles of plastic main, and 5 miles of other types of main. Collectively, these mains are linked together to form systems that deliver natural gas service to approximately 135,000 residential, commercial, and industrial customers in 30 counties.

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

A: Columbia's distribution infrastructure is the final step in the delivery of natural gas to customers from the natural gas producing regions of the United States. Columbia distributes natural gas by taking it from points of delivery, also known as "city gates," along interstate and intrastate pipelines then distributing it through 2,562 miles of distribution main that network underground between and through cities, towns and neighborhoods. The natural gas is then delivered by way of approximately 135,000 customer service lines to meet the demands of Columbia's residential, commercial and industrial end-use customers.

Columbia receives the natural gas commodity at the "city gate" where the transmission pressure of the gas is generally reduced to a lower pressure. An odorant known as mercaptan is often added to the natural gas at the city gate before it is delivered into the distribution system. The gas then flows through Columbia's distribution system where additional pressure reduction typically occurs in a series of district regulator stations before being delivered to each customer.

COLUMBIA'S CAPITAL PROGRAM

Q: How does Columbia categorize its capital program?

A: Columbia's capital expenditures are categorized and allocated across the following eight business classes:

1. *Growth (also referred to as "New Business"):* expenses in this category are used for any facilities that are required to serve new customers.

2. Betterment ("Capacity" or "Compliance"): expenses in this category include facilities that are required to improve system reliability or provide additional capacity for existing customers.

3. Replacement (also referred to as "Age and Condition"): expenses in this category are for any facilities that must be replaced due to damage or physical deterioration in situations where repair is not feasible.

4. Public Improvement (also referred to as "Mandatory Relocation"): expenses in this category are for any facilities that must be relocated or raised/lowered to meet the requirements of municipal roadway reconstruction projects.

5. *Support Services:* This category is used to capture capital expenditures that are not directly related to the installation of distribution facilities. This includes expenditures for capitalized tools/equipment and small facility improvements.

6. *Segment IT:* expenses in this category include capital investments in information technology that is specifically identified and sponsored by the NiSource's gas distribution ("NGD") management team.

7. *Corporate IT:* expenses in this category include capital investments in information technology, such as the common general ledger and chart of accounts system, that is allocated to NGD as NiSource corporate expenditures and managed by NiSource Corporate IT with assistance from applicable operating company personnel.

8. *Automated Meter Reading ("AMR"):* expenses in this category include the cost of targeted AMR deployment programs.

Q: Please describe Columbia's capital planning and allocation process.

A: Columbia's capital planning process is integral to the overall success of the Company. In order to ensure the effectiveness of this process, a capital program management team serves as the primary administrator for the capital budget. This team facilitates consistent capital planning and allocation across NGD, optimizes capital spending, monitors and forecasts capital expenditure, and communicates capital information to key internal departments and stakeholders.

The capital budgeting and planning process for NGD is a continual management process and includes key milestones in preparation for the subsequent year's capital expenditure program. Every year during the months of April and May, NGD's Director of Capital Program Management will facilitate meetings with the Engineering Managers to discuss in detail progress on the current year's capital program and any expected capital requirements for the following few years. This information is used to develop a multi-year capital investment plan that NGD will utilize to develop its preliminary capital budget for subsequent year. Capital needs for the following year will be reviewed and studied further prior to the annual corporate capital planning meeting held in July or August. These capital reviews, which are completed by the engineering department, generally include evaluation of any projected material changes in customer growth related activity, system improvement requirements resulting from winter operations, changes in public improvement relocation activity, and age and condition related replacement activity that would result in significant increases in capital. During this review period, the engineering department prioritizes the results from Optimain DS™, a decision support and risk analysis software provided by Opvantek, Inc. Optimain DS™ is a client-server application that runs on Windows XP or higher workstations. Columbia utilizes this software along with other factors to ensure consistency, continuity, and optimization of its capital program; with emphasis placed on accelerating the replacement of unprotected bare steel, cathodically protected bare steel, cathodically unprotected coated steel, cast iron and wrought iron. Columbia defines these types of mains as "Priority Pipe" or "Priority Mains" and capital expenditure towards this replacement activity represents a significant component of the overall capital program. AMRP related projects planned for the subsequent year will be reviewed and selected using these assessment models and other factors during the months of April, May, and June.

In July or August, NGD's formal request for capital is presented to NiSource executive management at the annual corporate capital planning meeting. Executive management finalizes the capital budget for the next fiscal year and submits for NiSource Board of Directors approval in November or December. The approval of the annual NGD capital program constitutes approval of the allocation to Columbia's capital budget and responsibility to maintain effective oversight and management of its capital expenditure at the engineering management level.

Q: **Are Columbia's capital expenditures generally consistent with its capital budgets?**

A: Yes. Columbia has consistently demonstrated the ability to successfully manage and execute on its capital program. Throughout the NGD business unit, the aspiration of the engineering and construction department is to be the industry leader in the execution of gas distribution capital programs. Columbia's track record of effective capital management over the last five years supports this vision and clearly positions Columbia for future success. From 2008 – 2012, Columbia's total capital approved budget was $64.6 million for the eight business classes. Columbia's capital expenditures for this same time period totaled $69.9 million. This positive variance of $5.3 million dollars over five years represents a positive variance of 8.2 percent. Columbia's annual goal has been to spend capital wisely and to ensure that all prudent efforts are made to avoid an overrun or underrun of the capital program. In short, Columbia has maintained its ability to perform in the area of capital budget management over this five year period. As a result, Columbia and the overall NGD business unit have developed a high level of credibility within NiSource concerning its ability to successfully execute on its capital program. Columbia witness Miller will further discuss Columbia's capital management credibility along with a proposal related to its variance or slippage factor.

Q: **Please describe Columbia's capital program for the forecasted test period ending December 2014.**

A: In 2014, Columbia intends to spend approximately $27.1 million across eight business classes which include: growth, betterment, public improvement, age & condition replacement, support services, segment IT, corporate IT, and AMR

Q: **What are Columbia's plans with respect to an Automated Meter Reading program?**

A: Over the course of 2014, Columbia intends to spend approximately $7 million on installing and implementing an AMR system. The AMR devices transmit data to a radio-equipped handheld computer or vehicle-based mobile computer collection system. The AMR device attaches to the gas meter and encodes consumption information from the meter to the radio-equipped data sending device. These gas modules work equally well indoors and outdoors and are powered by lithium batteries that provide an average battery life of 20 years.

Q. **Do AMRs benefit customers?**

A. Yes. Customers benefit from AMR technology in numerous ways, including increased meter reading performance, reduction in estimated bills for inaccessible meters and resulting rebills, improved customer satisfaction by eliminating the need for customers to make arrangements to let meter readers inside their homes, identification of energy theft and revenue loss due to meter tampering, and improved employee safety.

Q: **Describe Columbia's AMRP.**

A: A significant percentage of Columbia's gas distribution mains and services are reaching the end of their useful life. In 2008, Columbia began its AMRP to more aggressively replace these mains and services than in the past. In order to provide safe, reliable delivery of gas service, Columbia began replacing certain types of gas main and services through continued evaluation, planning and prioritization based on the serviceability of these systems. The types of main identified and targeted for replacement in Columbia's AMRP are unprotected bare steel, cathodically protected bare steel, cathodically unprotected coated steel, cast iron and wrought iron. Columbia identifies these types of mains as "Priority Pipe" or "Priority Mains." As part of its AMRP, Columbia is also replacing all metallic service lines, and service lines that do not meet current material and construction standards. Columbia plans to replace these mains, service lines, and associated appurtenances over a span of approximately thirty years, which began in 2008. Columbia estimated that the total program would cost approximately $210 million to replace 525 miles of Priority Pipe.

Q. What progress has Columbia made in its AMRP program from 2008 through 2012?

A. Columbia's capital expenditures during 2008 through 2012 have enabled Columbia to effectively accelerate the replacement of sections of its aging infrastructure and specifically target some of the worst segments for replacement. Through the first five years of the AMRP program, Columbia spent approximately $45 million and has replaced approximately 70 miles of Priority Pipe and associated service lines and/or appurtenances.

Q. What are Columbia's AMRP related capital plans over the next four years?

A: While annual replacement funding can vary from year-to-year, based on system condition, performance, and corporate-wide capital funding, over the next four years, Columbia intends to continue accelerating the replacement of Priority Pipe by spending over $50.8 million on the AMRP program. For 2013, Columbia anticipates that it will spend $14.2 million in replacing Priority Pipe. For 2014 through 2016, the AMRP related capital spend is estimated at $12.2 million annually. Columbia witness Cooper will discuss proposals related to Columbia's recovery of costs associated with the AMRP.

Q: How are AMRP replacement projects prioritized?

A: To aid in identifying and selecting AMRP projects, Columbia's engineering department utilizes the decision support software called Optimain DS™ to analyze relative risks associated with distribution systems. With Optimain DS™, Columbia is able to evaluate and rank pipe segments system-wide against a range of environmental conditions (e.g. population density, building class, surface cover type, etc.), risk factors (pipe segment leak history, pipe condition, pitting depth, depth of cover, etc.) and economic factors. Columbia's engineering department focuses on identifying areas with higher concentration of risk as the starting point of project selection. Areas with higher concentration of risk are evaluated to determine the appropriate plan of action that addresses the replacement strategy for the area and desired long term system design. Columbia's engineering department consults with the operations department to obtain its input on any other operational or system reliability issues in the area.

Q. What factors are taken into consideration during the prioritization process?

A. One example of an operational or system reliability issue that's taken into consideration involves the history of loss of service to customers due to ground water infiltrating existing pipe and service lines. Also identified as "water-offs" or "freeze-offs", this system reliability condition generally is a result of past leakage in an area where Columbia operates a low pressure system. With the completion of AMRP projects, Columbia has been able to address many of these operational or system reliability issues across its systems by replacing aging low pressure priority pipe primarily with plastic pipe that can be operated at elevated pressures, thereby eliminating the chance of water entering the system.

Other factors that Columbia considers when selecting projects include information received from external stakeholders on any identified municipal projects within an area that would substantially influence our decision to proceed with construction. For example, planned or pending roadway improvement work, sewer line replacement work, or waterline replacement work is taken in consideration when selecting projects. Columbia remains committed on collaborating with local and state public improvement stakeholders to coordinate its AMRP projects with planned or pending municipal construction projects where possible. This effort helps to minimize our need to perform additional construction or maintenance in areas after public improvement project has been completed.

Q: **Has Columbia maintained its ability to successfully execute on the AMRP?**

A: Yes. In fact, Columbia has increased its capital program and, as I previously explained, Columbia anticipates that it will spend approximately $14.2 million in replacing priority pipe in 2013 and approximately $12.2 million annually through 2016. Specific replacement projects have been identified, planned, and designed. Columbia has developed a 16-month inventory of replacement projects and will increase the inventory to 24 months prior to the end of 2013. Additionally, Columbia continues to assess the complexity of managing AMRP projects and evaluated internal and external resource needs, construction practices, computer applications and analysis tools, communication strategies, opportunities to leverage economies of scale for materials, and developing program plans and goals.

Q: Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Eric T. Belle, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Eric T. Belle

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by Eric T. Belle on this the 23rd day of May, 2013.

NOTARIAL SEAL STATE OF OHIO

CHERYL A. MacDONALD
Notary Public, State of Ohio
My Commission Expires
March 26, 2017

Notary Public

My Commission expires: MARCH 26, 2017

Columbia Exhibit No.________

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF WILLIAM J. GRESHAM ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF WILLIAM J. GRESHAM

Q. Please state your name and business address.

A. My name is William J. Gresham. My business address is 200 Civic Center Drive, Columbus, OH 43215.

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

A. I am Manager of Forecasting for NiSource Corporate Services Company. I am responsible for developing short-range and long-range forecasts of customers, energy consumption and peak demand for seven NiSource gas distribution companies, including Columbia Gas of Kentucky ("Columbia" or the "Company"), and one NiSource electric company. I also manage other business related analyses and forecasts.

Q. Please summarize your educational background and professional experience.

A. I attended Oklahoma State University where I earned a Bachelor of Science Degree in Business Administration and a Master of Science Degree in Economics. From 1978 to 1982, I worked as a forecast analyst responsible for residential and commercial customer and energy forecasts for Houston Lighting and Power Company, an investor-owned electric utility. From 1982 to 1985, I was a senior business analyst for the oilfield equipment division of ARMCO, Inc. where I developed product-line forecasts and assisted in strategic planning. From 1985 to 1987, I was Director of Research at Rice Center, a consulting company affiliated with Rice University, where I supervised an economics section and managed economic and demographic consulting projects.

In 1987, I joined Columbia Energy Group ("CEG") as Demand Research Coordinator responsible for developing forecasts of customers and energy consumption for six gas distribution companies. I was promoted to Manager of Forecasting in 1990, a post I held until the CEG merger with NiSource in 2000. Currently, I am Manager of Forecasting for all NiSource distribution companies.

Q. Have you previously testified before this or any regulatory or governmental bodies?

A. Yes. I have provided testimony concerning forecasting and weather normalization in regulatory proceedings in Virginia, Indiana, Ohio, Kentucky, Maryland, Pennsylvania and Massachusetts.

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

A. The purpose of my testimony is to explain the projection of future test year customers and volume. My testimony also will discuss the trend in residential consumption per customer.

Q. Do you sponsor filing requirements in this case?

A. Yes. I sponsor the forecasted customer counts and sales volume in Filing Requirements 12-h-14 and 12-h-15.

FORECAST METHOD

Q. How did you arrive at the forecasted number of customers and their consumption for the forecasted test period?

A. The forecast is developed by the Forecasting Group with input from the Large Customers Relations Team and the New Business Team. The Forecasting Group is responsible for most concepts with the New Business Team providing a forecast of residential and commercial new customer additions and the Large Customer Relations Group providing volumetric forecasts for large commercial and industrial customers. All groups report through the corporate services function.

Residential and Commercial Customers

- Residential and Commercial customers are forecasted as two concepts, new customer additions and attrition. The forecasted December customer count is the customer count from the previous December plus customer additions for the year less customer attrition. New customer additions are forecasted by the New Business Team based on their knowledge of the business climate, new construction activity and interviews with active builders and developers, and the potential for conversions from alternate fuels. This knowledge is applied to the current year projected annual new customer additions to arrive at the forecast for future years. To arrive at the current year projected annual new customer additions, the New Business Team monitors potential projects being engineered, residential single family and multi family construction permit applications, and outstanding natural gas service requests. Customer attrition is forecasted at a typical historical level by the Forecasting Group.

- The Small Volume Gas Transportation Service (CHOICE) customer count is calibrated to the most recently observed level of CHOICE customers and a saturation rate (percent of total customers) is calculated. The forecast is obtained by applying the observed saturation rate to the forecasted total number of customers. The forecast is developed for residential and commercial customers separately with a constant saturation percentage.
- Transportation customers not in the CHOICE program are referred to as traditional transportation customers and are set equal to existing traditional transportation customers plus new traditional transportation

customers identified by the New Business Team.

- Sales customers = total customers less CHOICE customers less traditional transportation customers

Residential and Commercial Mcf per Customer

- Residential Mcf per customer is forecasted with an econometric model that incorporates weather, real price, a space heating average efficiency variable, and real personal income per capita. Residential CHOICE Mcf per customer is calibrated to the most recently observed level and then forecasted with the same annual percentage change as that for the residential class as a whole.
- Commercial Mcf per customer is forecasted with an econometric model that incorporates weather, real price, a space heating average efficiency variable, and real gross county product. Commercial CHOICE Mcf per customer is calibrated to the most recently observed level and then forecasted with the same annual percentage change as that for the commercial class as a whole.

Residential and Commercial Volume.

- Throughput forecasted for existing and new construction customers

    Throughput = customers multiplied by Mcf/customer

- CHOICE volume forecasted as

  CHOICE volume = customers multiplied by Mcf/customer

- Sales volume forecasted as residual

  Sales volume = throughput less CHOICE volume less traditional transportation volume

- The majority of the traditional transportation volume for the commercial class is forecasted for large commercial customers by the Large Customer Relations group as described in the Industrial Volume section below and is supplemented with an "all other" forecast provided by the Forecasting Group. The "all other" portion is assigned the growth rate from the class total model adjusted for the growth in the large customer segment.

Industrial Volume

- The Large Customer Relations group generates a forecast of volume for large industrial customers which represents 95% of the industrial class volume. This forecast includes discussions with industrial customers about their upcoming plans and expected levels of gas consumption, historic consumption of the customer, and industry trends. In addition, volumes are included for identified potential large customers that are actively considering the use of gas. The Forecasting Group uses an econometric model to forecast total volume of all industrial customers. The econometric model incorporates real price, manufacturing employment, and industrial production. The "all other" portion of the industrial volume, that not forecasted by the Large Customer Relations group, is assigned the growth rate from the class total model adjusted for the growth in the large customer segment.

- The Large Customer Relations forecast provides the level of transportation service for the large customers. Industrial sales are held constant so that the growth assigned to "all other" industrial is attributed to traditional transportation. Industrial CHOICE customers and Mcf are set equal to the most recently observed level and held constant.

Q. What are the major assumptions in this forecast?

A. The major assumption for the New Business Team forecast of customers is an improving climate for new residential and commercial construction. The large industrial forecast is based on the customer specific and new project forecasts described above, and does not attempt to forecast unknowns such as unpredictable plant closures. The forecasts from the econometric models contain forecasted levels of the independent variables obtained from various sources. Gas costs are obtained from the

Columbia's gas supply model that uses the NYMEX strip as its estimate of gas prices. These gas costs are used in a simulation of Columbia's gas cost adjustment with current margin rates to arrive at end user prices. Normal weather is set to the average of the 20 years ended 2012, which represents an update to the definition of weather used in the billing determinants underlying current rates, the 20 years ended 2008. This is different from the definition used in the NiSource corporate level forecast for all its distribution companies, which is the 35 years ended 2010. NiSource has chosen this common definition for its portfolio of companies to facilitate comparisons between and among the companies. End use energy efficiency measures are provided by Itron, an energy industry consulting firm. Economic variables such as personal income, gross county product and industrial production are obtained from IHS Global Insight, an economic consulting firm.

Q. What software and models are used in the forecast?

A. The New Business and the Large Customer Relations teams develop custom applications with the Microsoft Office Suite. The gas supply model for gas costs is the SENDOUT Gas Planning System from Ventyx, Inc. End user prices are calculated with a custom program in mainframe

FORTRAN and desktop accounting software from Longview. The forecasting group uses SAS statistical software to estimate and solve its econometric models.

Q. Has Columbia's forecast method proven reliable?

A. Yes. These summary tables show that the residential and commercial forecasts for one and two years ahead have both positive and negative variances that average less than one percent. The annual volume is normalized for weather. It is not surprising that the percent differences are somewhat larger for the industrial class where results can be significantly affected by a few large customers whose output may be sensitive to economic and capital goods cycles.

Columbia Gas of Kentucky - Residential MMCF Forecast Performance

	Annual MMCF	Year 1 Forecast	Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast
2009	8,849	8,856		7		0.1%	
2010	8,673	8,913	8,710	240	37	2.8%	0.4%
2011	8,793	8,496	8,647	-297	-146	-3.4%	-1.7%
2012	8,265	8,516	8,307	251	42	3.0%	0.5%
Average	8,645	8,695	8,555	50	-22	0.6%	-0.3%

Columbia Gas of Kentucky - Commercial MMCF Forecast Performance

	Annual MMCF	Year 1 Forecast	Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast
2009	7,694	7,525		-169		-2.2%	
2010	7,595	7,981	7,459	386	-136	5.1%	-1.8%
2011	7,534	7,398	7,986	-136	452	-1.8%	6.0%
2012	7,662	7,720	7,301	58	-361	0.8%	-4.7%
Average	7,621	7,656	7,582	35	-15	0.5%	-0.2%

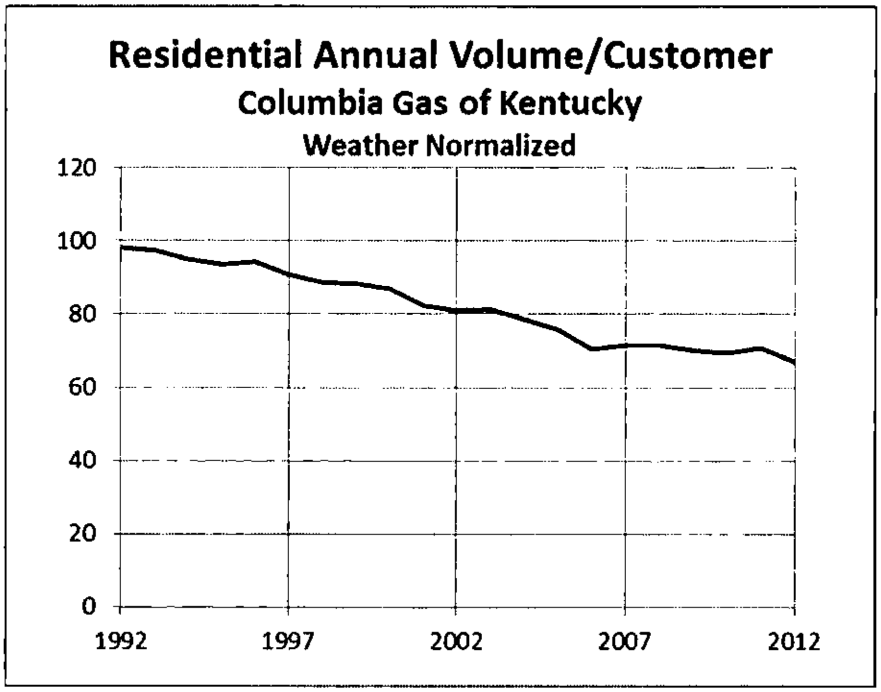
Columbia Gas of Kentucky - Industrial MMCF Forecast Performance

	Annual MMCF	Year 1 Forecast	Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast	Difference Year 1 Forecast	Difference Year 2 Forecast
2009	15,719	16,637		918		5.8%	
2010	17,024	14,373	16,604	-2,651	-420	-15.6%	-2.5%
2011	16,225	15,563	14,442	-662	-1,783	-4.1%	-11.0%
2012	16,265	15,619	15,498	-646	-767	-4.0%	-4.7%
Average	16,308	15,548	15,515	-760	-990	-4.7%	-6.1%

TREND IN RESIDENTIAL USE PER CUSTOMER

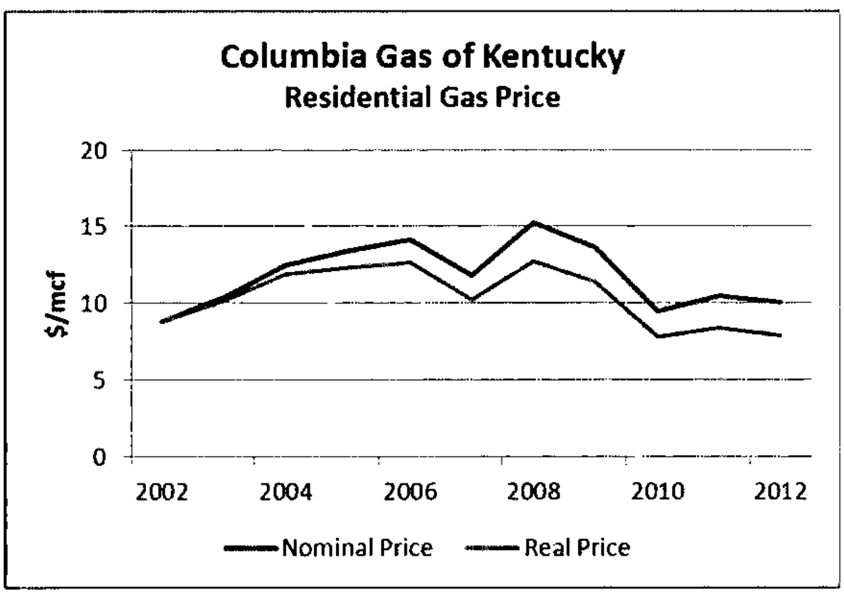
Q. Describe Columbia's recent trends related to residential use per customer.

A. The graph below illustrates the recent trends in Columbia's residential use per customer. Weather normalized use per customer for residential customers has fallen 31% since 1993 and 17% over the last 10 years. The data show that there are only a few years with an increase in use. All of these periods were followed by decreases, indicating that these points were not representative of the overall trend.



Q. **What factors have caused the reduction in customer usage?**

A. The reduction in customer usage of approximately 1.9% per year for the past 10 years and 1.2% in the last 5 years is caused by structural conservation – a decline in usage independent of trends in residential natural gas prices. As the graph below of nominal and real residential gas prices (real stated in 2002 dollars) illustrates that prices rose through 2006 and declined thereafter. The decline in customer usage experienced in the first half of this decade, which was marked by rising prices, was not reversed by increasing usage in response to falling prices during the second half of the decade. This structural conservation is a result of a lengthy history of increased appliance efficiency and more efficient construction standards that followed the major price increases that occurred in the 1970s and 1980s. Annual conservation increased significantly with the large price increases that occurred in the winters of 2000-2001, 2004-2005, and 2005-2006. With limited end uses for natural gas, increasing appliance efficiency, and higher building standards, the downward trend in consumption per customer will continue. Appliance choice could also become a significant factor. If customers are encouraged to choose high efficiency furnaces, electric water heaters, cooking ranges, and heat pumps, the potential floor will fall with appliance saturation as well as efficiency. This consideration is particularly relevant in Kentucky where electricity rates are low and are more likely to be competitive with natural gas prices than in states with higher electric rates.



Q. Does use per customer for the commercial class show the same trend?

A. No. The heterogeneity of customer type and end uses within the commercial class yields use per customer related to customer mix and economic factors. For example, levels and patterns of usage for a small retail store are reasonably expected to diverge greatly from those of a large hospital. Furthermore, the changing mix of customer types within the commercial class contributes to the difficulty in discerning trends in use per customer. The assumption of a representative customer is much more reasonable for the residential class than it is for the commercial class. For this reason, usage per customer for the commercial class is expected for the future test year to be relatively close to that observed at the end of the historical period. In fact, commercial use per customer increases slightly in the forecasted period.

Q. Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates) of Columbia Gas of Kentucky, Inc.)	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, William J. Gresham, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

William J. Gresham

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by William J. Gresham on this the 24th day of May, 2013.

NOTARIAL SEAL STATE OF OHIO

CHERYL A. MacDONALD
Notary Public, State of Ohio
My Commission Expires
March 26, 2017

Notary Public

My Commission expires: MARCH 26, 2017

Paul R. Moul

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

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

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

Columbia Gas of Kentucky, Inc

Direct Testimony of Paul R. Moul

Table of Contents

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

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

PREPARED DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q: What is the purpose of your direct testimony?

A: My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Public Service Commission of the Commonwealth of Kentucky (the "Commission") should allow Columbia Gas of Kentucky, Inc., ("Columbia" or the "Company") to realize as a result of this proceeding that apply to its gas distribution operations. My analysis and recommendation are supported by the detailed financial data set forth in Attachments PRM-1 through PRM-15. I also sponsor Schedule J and Filing Requirement 12-h-11.

Q: Based upon your analysis, what is your conclusion concerning the

appropriate rate of return for the Columbia in this case?

A: My conclusion is that the Company's overall rate of return is 8.59%, which contains a cost of common equity of 11.25%. It is my opinion that the Commission should adopt this rate of return and cost of equity as part of its determination of the Company's rates. I have presented the weighted average cost of capital for the Company on page 1 of Attachment PRM-1 and details of my cost equity on page 2 of Attachment PRM-2. The weighted average cost of capital that I determined is based upon Columbia's thirteen-month average capitalization for the fully forecasted test period ending December 31, 2014. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital; should, if adopted by the Commission, establish a compensatory level of return for the use of such capital; and should provide the Company with the ability to attract capital on reasonable terms.

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

A: Columbia is an indirect wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource is a holding company that owns subsidiaries engaged in natural gas transmission and storage and the distribution of natural gas and owns Northern Indiana Public Service Company, a combination electric and gas utility operating in Indiana. NiSource also has other energy related investments.

The Company provides natural gas distribution service to approximately 135,000 customers in central and eastern Kentucky. Throughput to its customers in 2012 was represented by approximately 18% to residential sales customers, 9% to other sales customers, and 73% to transportation customers. The Company's largest customers receive 17,038,154 Mcf of deliveries, or approximately 54% of total Company throughput. This means that the Company's throughput is highly concentrated in a few customers, which can have a significant impact on the Company's operations.

Columbia's flowing gas is provided by transportation arrangements with interstate pipelines and with local producers. The Company supplements its flowing gas supplies with gas withdrawn from underground storage.

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

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

Q: In your opinion, what factors should the Commission consider when determining Columbia's rate of return in this proceeding?

A: The Commission's rate of return allowance must be set to cover Columbia's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

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

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

A: It is necessary to use a proxy group of companies to measure the Company's cost of equity because its stock is not traded. As noted above, the Company's stock is completely owned by NiSource through intermediate holding companies. The use of a proxy group to measure the Company's current cost of equity is a common practice of analysts performing these types of studies. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of nine (9) gas companies. The companies are: AGL Resources, Inc., Atmos Energy Corp., Laclede Group, Inc., New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc. I will refer to these companies as the "Gas Group" throughout my testimony.

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

A: I began with the universe of gas utilities contained in the basic service of The Value Line Investment Survey, which consists of eleven companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. Value Line is a database that is familiar to the Commission, and is widely available to investors. Value Line is frequently used by utility witnesses and witnesses for the Attorney General in public utility rate cases. I eliminated two companies from the Value Line group when I assembled my Gas Group. The eliminations were NiSource due to its electric operations and its natural gas pipeline and storage operations and UGI Corporation because of its highly diversified businesses. The remaining nine companies are included in my Gas Group.

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

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

Q: Please summarize your cost of equity analysis.

A: My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity. The following table, derived from the model results presented on page 2 of Attachment PRM-1, provides a summary of the indicated costs of equity using each of these approaches.

	Excluding Flotation	Including Flotation[2]
DCF	9.49%	9.68%
RP	12.00%	12.19%
CAPM	10.91%	11.10%
Comparable Earnings	12.85%	12.85%
Measures of Central Tendency:		
Average	11.31%	11.46%
Median	11.46%	11.65%
Mid-point	11.17%	11.27%

From these results, the return for the Company would be 11.25%. My

[2]Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

recommended rate of return on common equity of 11.25% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events, such as unexpected spikes in the cost of purchased products and other expenses. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Indeed, in a study prepared for the American Gas Foundation, it was noted that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. Furthermore, the report specifically found that returns below 10% would trigger broad disenchantment with LDC investment.

NATURAL GAS RISK FACTORS

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

A: Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for large volume customers. Columbia witness Miller will discuss the particular challenges facing the Company.

Natural gas utilities have focused increased attention on safety and reliability issues. Consequently, natural gas companies are now allocating more of their resources to address new and pending pipeline safety regulations and infrastructure issues.,

Q: How does Columbia's throughput to large volume customers affect its risk profile?

A: Success in this aspect of Columbia's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence Columbia's throughput to these customers, which face competitive pressure on their operations from facilities located outside Columbia's service territory. Columbia's risk profile is strongly influenced by natural gas sold/delivered to customers engaged in petroleum refining, automobile assembly, and the manufacturing of steel, glass, and chemicals, as discussed by Columbia witness Miller. Indeed, throughput to its largest customers represents 54% of total throughput as previously noted. Large volume users that have traditionally used transportation service also have the ability to bypass Columbia's facilities. Indeed, three former customers have already bypassed Columbia's facilities. And, Columbia has identified eight additional customers that represent a bypass threat. Columbia has been proactive to the threat of bypass by working with its customers that are in close proximity to interstate pipelines.

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

A: Columbia is required to undertake investments to maintain and upgrade existing facilities in its service territories. To maintain safe and reliable service to existing customers, Columbia must invest to upgrade its infrastructure. The rehabilitation of Columbia's infrastructure represents a non-revenue producing use of capital. Columbia has approximately 470 miles of its distribution mains constructed of unprotected bare steel and cast iron that are to be replaced pursuant to its main replacement program. Also, Columbia has 12,005 of its services constructed of unprotected bare steel that will also be replaced along with its main replacement program. Columbia projects its construction expenditures through 2018 will be:

2013	$	24,625,000
2014		27,062,000
2015		19,809,000
2016		19,846,000
2017		19,179,000
Total	$	110,521,000

Over this period, these capital expenditures will represent approximately 58% ($110,521,000 ÷ $190,128,100) of its net utility plant at December 31, 2012. As previously noted, a fair rate of return represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its needs on reasonable terms.

Q: **Does your cost of equity analysis and recommendation take into account the weather normalization adjustment ("WNA") that is presently in effect for the Company?**

A: Yes. The WNA is intended to separate revenues from variations in sales related to usage caused by variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in a test year context. My cost of equity analysis that provides an 11.25% rate of return on common equity takes into account the Company's WNA.

Q: **How have you reflected the effect of the WNA in your analysis?**

A: Most of the companies included in my Gas Group already have tariff mechanisms similar to the WNA and other tariff features designed to stabilize revenues. Therefore my analysis already reflects the impacts of the WNA and other revenue stabilization mechanisms on investor expectations through the use of market-determined models. All but one of the companies in my Gas Group already has some form of revenue stabilization mechanism. The sole exception is Laclede, which has a weather mitigated rate design that recovers its fixed costs more evenly during the heating season. Therefore, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust revenues for abnormal weather and other occurrences.

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

Q: How should the Commission respond to the issues facing the natural gas

utilities and, in particular, Columbia?

A: The Commission should recognize and take into account the competitive environment and the risk it poses in the natural gas business in determining the cost of capital for Columbia, and provide a reasonable opportunity for Columbia to actually achieve its cost of capital.

FUNDAMENTAL RISK ANALYSIS

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

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

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

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

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

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

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

A: Presently, Columbia has no bond rating because its debt is owned by an affiliate. The corporate credit rating ("CCR") for NiSource is BBB- from Standard and Poor's Corporation ("S&P"), and the Long Term ("LT") issuer rating is Baa3 from Moody's Investors Services ("Moody's"). The ratings for NiSource are at the bottom of the investment grades. For the Gas Group, the average LT issuer rating is A3 by Moody's and the average CCR is A- by S&P,

as displayed on page 2 of Attachment PRM-3. The LT issuer rating by Moody's and the CCR designation by S&P focus upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is Baa1 by Moody's and BBB+ by S&P, as displayed on page 3 of Attachment PRM-4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

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

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

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

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[3]

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

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher

[3]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).

financial risk. The five-year average common equity ratios, based on total capital were 53.9% for Columbia of Kentucky, 55.4% for the Gas Group, and 45.0% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.142 (1.5% ÷ 10.6%) for Columbia, 0.073 (0.8% ÷ 10.9%) for the Gas Group, and 0.104 (1.1% ÷ 10.6%) for the S&P Public Utilities. The Company's rates of return were more variable than the Gas Group and the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[4] The five-year average operating ratios were 88.3% for Columbia, 88.1% for the Gas Group, and 82.3% for the S&P Public Utilities. Columbia and the Gas Group had higher operating ratios than the S&P Public Utilities.

[4]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.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 4.61 times for Columbia, 4.49 times for the Gas Group, and 3.12 times for the S&P Public Utilities.

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

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 66.7% for Columbia, 100.1% for the Gas Group, and 91.1% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[5] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.66 as the average for the Gas Group (see page 2 of Attachment PRM-3) and 0.75 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-4).

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

A: While the Gas Group in certain respects provides useful evidence of the cost of equity, Columbia's capital costs are higher due to its greater risk. Columbia's higher risk is revealed by the lower credit quality ratings of NiSource, its smaller size, its higher earnings variability, and its lower IGF to construction.

[5] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. 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.

As such, the cost of equity for the Gas Group would only partially compensate for Columbia's higher risk. Therefore, the Gas Group's indicated cost of equity provides a conservative representative of the risk for Columbia in this case.

CAPITAL STRUCTURE RATIOS

Q: Does Attachment PRM-5 provide Columbia's capitalization and capital structure ratios?

A: Yes. Attachment PRM-5 presents Columbia's capitalization and related capital structure ratios. The February 28, 2013 capitalization corresponds with the latest actual data for the Company. The August 31, 2013 capital structure is estimated at the end of the base period that consists of six-months of actual data and six-months of projected data. The December 31, 2014 capital structure is estimated at the end of the fully forecasted test period. Prior to the end of the fully forecasted test period, the Company plans to refinance $14 million of maturing long-term debt and to provide new debt capital to finance its rate base additions. The new issues of debt will consist of $21 million, which will take place in 2013, and an additional $2 million in 2014. The resulting capital structure ratios are 47.34% long-term debt, 0.27% short-term debt, and 52.39% common equity.

Q: Are these capital structure ratios reasonable?

A: Yes. I have verified the reasonableness of the Company's common equity ratio by considering the historical capital structure ratios for the Gas Group and with analysts' forecasts, which influence investor expectations. For the historical comparison, the Gas Group had a 56.0% common equity ratio at year-end 2012 calculated without short-term debt. My comparison of these ratios rests on a calculation without short-term debt because the Company uses a thirteen-month average for ratesetting purposes, while the GAAP financial reports for the Gas Group use fiscal year-end balances of short-term debt. This comparison shows that the Company's common equity ratio is reasonable. I have also compared the Company's proposed common equity ratio to that of the Gas Group based upon forecast data widely available to investors from Value Line. In the case of the Value Line forecasts, the common equity ratios are computed without regard to short-term debt. Those ratios are:

Company	2012	2013	2015-17
AGL Resources, Inc.	48.0%	47.5%	44.0%
Atmos Energy Corporation	54.5%	55.0%	51.0%
Laclede Group, Inc.	64.0%	61.5%	62.5%
New Jersey Resources Corp.	60.8%	60.5%	66.0%
Northwest Natural Gas Co.	53.0%	53.0%	52.5%
Piedmont Natural Gas Company	50.0%	50.0%	50.0%
South Jersey Industries, Inc.	56.0%	57.0%	57.0%
Southwest Gas Corporation	51.0%	52.0%	51.5%
WGL Holdings, Inc.	67.5%	68.0%	70.5%
Average	56.1%	56.1%	56.1%

Source: The Value Line Investment Survey, December 7, 2012

These forecasts show that the 52.23% common equity ratio for Columbia, which includes short-term debt, is reasonable by reference to the forecast ratios of the Gas Group.

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

A: Since rate setting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the fully forecasted test period. As a result, I will adopt the Company's fully forecast test period capital structure ratios of 47.49% long-term debt, 0.28% short-term debt and 52.23% common equity. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

COST OF SENIOR CAPITAL

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

A: The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Attachment PRM-6, I have computed the actual embedded cost rate of debt at February 28, 2013, and estimated at August 31, 2013 and December 31, 2014. And on page 2 of Attachment PRM-6, the embedded cost of debt is shown for December 31, 2014 using the thirteen-month average balances. For the new issue of long-term debt, I have used an estimated cost of 5.24% for the issue in December 2013. This interest rate reflects the formula used by the Company for issuing debt to NiSource Finance. In this case, the yield on 30-year Treasury obligations forecast for December 2013 is 3.105% plus a spread of 2.14% for Baa3/BBB- rated debt taken from the Reuters Corporate Spreads for Utilities. The resulting interest rate is 5.24% (3.105% + 2.14%). For the issue placed in November 2014, the cost is 5.28% (3.182% + 2.10%) using the same estimation procedure.

I will adopt the 5.68% embedded cost of long-term debt, as shown on page 2 of Attachment PRM-6. This rate is related to the amount of long-term debt shown on Attachment PRM-5 which provides the basis for the 47.49% long-term debt ratio.

Q: What cost rate have you assigned to the short-term debt?

A: I have used a cost of short-term debt of 1.94%, which represents the Company's estimate for the fully forecasted test period. The Company obtains its short-term debt from the NiSource money pool, which has a credit facility with a syndicate of banks. The interest rate is established as the one-month LIBOR plus 147.5 basis points, which represents the credit facility spread. Here, the Company's estimate is comprised of the 0.470% LIBOR plus the spread, i.e., 0.470% + 1.475% = 1.945%.

DISCOUNTED CASH FLOW

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

A: The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on page 2 of Attachment PRM-1 for the Gas Group. The DCF return is 9.49% to which flotation costs are added to provide a 9.68% final result.

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

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

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

A: The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. The monthly dividend yields for the twelve months ended February 2013 are shown on Attachment PRM-7 and capture an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended February 2013, the average dividend yield was 3.81% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.82% and 3.83%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.82% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Attachment PRM-7. That adjusted dividend yield is 3.92% for the Gas Group.

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

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

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

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

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

Q: What data for the proxy group 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 historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM-8, the historical growth of earnings per share was in the range of 5.22% to 6.39% for the Gas Group.

Attachment PRM-9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, SNL Financial, Zacks, Morningstar, and Value Line. IBES/First Call, SNL Financial, Zacks, and Morningstar represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, SNL Financial, and Zacks growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, SNL Financial, Zacks, and Morningstar estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, SNL Financial, Zacks, and Morningstar forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Attachment PRM-9 for the Gas Group.

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

A: As to the five-year forecast growth rates, Attachment PRM-9 indicates that the projected earnings per share growth rates for the Gas Group are 5.08% by IBES/First Call, 4.64% by SNL Financial, 4.51% by Zacks, 4.27% by Morningstar, and 4.94% by <u>Value Line</u>. The <u>Value Line</u> projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 4.94%) than the dividends per share (i.e., 3.89%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

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

A: A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm.

However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts. Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth is the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments, and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[7] Hence, to follow Professor Gordon's findings, projections of

[7]Gordon, Gordon & Gould ,"Choice Among Methods of Estimating Share Yield," The Journal of

earnings per share growth, such as those published by IBES/First Call, SNL Financial, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Attachment PRM-9, provide a range of growth rates of 4.27% to 5.08%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.00% is within the array of earnings per share growth rates shown by the analysts' forecasts. While the growth rate that I determined for the DCF analysis is higher than the midpoint of the range noted above, it is reflective of growth that is associated with improving business conditions. The stellar performance of the stock market in 2013 points to an improving economy, as it is one of the leading economic indicators compiled by The Conference Board.[8] In fact, the Leading Economic Index, whose financial components include the stock market, has increased in five of the last six months. In addition, "the strengths among the leading indicators have become more widespread in recent months," said The Conference Board.

Portfolio Management (Spring 1989).

[8] The Conference Board U.S. Business Cycle Indicators -The Conference Board Leading Economic Index (LEI) for the U.S. and Related Composite Economic Indexes for February 2013 [Press Release]. Retrieved from http://www.conference-board.org/data/bci.cfm dated March 21, 2013

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

A: Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those capital structure ratios are 35.56% long-term debt, 0.11% preferred stock, and 64.33% common equity, as shown on Attachment PRM-10. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q: Please explain.

A: If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital based on a book value capital structure used for ratesetting purposes, the utility will not, by definition, recover its risk-adjusted capital cost. This is because market valuations of equity are based on market value capital structures, which in general have more equity and less debt and therefore reflect less risk than book value capital structures (see Attachment PRM-10 for the comparison). The utility's risk-adjusted cost of equity will necessarily be lower with the less risky market value capital structure than with the book value capital structure. The difference represents that portion of the utility's cost of equity that it will not recover unless either the market value cost of equity is applied to the utility's market value capital structure or it is adjusted to reflect the higher risk associated with the book value capital structure. By the same token, if the utility's market value capital structure is less than its book value structure, then the utility's market cost of equity should be adjusted downward to reflect the lower risk associated with the book value capital structure, or else the utility will over-recover its total cost of equity.

This shortcoming of the DCF has persuaded the Pennsylvania Public Utility Commission to adjust the DCF determined cost of equity upward to make the return consistent with the book value capital structure. Specific adjustments to recognize this risk difference were made in the following cases:

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

In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification.

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

A: The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Attachment PRM-10, under the heading "M&M," provides a return of 7.62% when applicable to a capital structure with 100% common equity.

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

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

Q: Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A: No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Attachment PRM-10, the equity return applicable to the book value common equity ratio is equal to 7.62%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 1.86% compensation for having a 44.25% debt ratio, plus 0.01% for having a 0.17% preferred stock ratio. The sum of the parts is 9.49% (7.62% + 1.86% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.92% dividend yield, the 5.00% growth rate, and the 0.57% for the leverage adjustment in order to arrive at the same 9.49% (3.92% + 5.00% + 0.57%) return. I know of no means to mathematically solve for the 0.57% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.57% adjustment is merely a convenient way to compare the 9.49% return computed directly with the Modigliani and Miller formulas to the 8.92% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio. Each of the calculations that I describe above apply to the market returns associated with the holding companies from which the DCF is derived. It is well understood that the leverage employed by the utility subsidiaries of those holding companies is reflective of the risks associated with the utility business.

Q: How have you measured the flotation cost allowance for the DCF return?

A: The flotation cost adjustment adds 0.19% (9.68% - 9.49%) to the rate of return on common equity for the Gas Group as shown by the calculations provided on page 2 of Attachment PRM-1. In my opinion, this adjustment is reasonable and supported by the analysis of natural gas utility stock issue shown on Attachment PRM-11. On that Attachment, I show that the average underwriters' discount and commission and company issuance expenses are 3.9% for the twelve issues of common stock shown there for the Gas Group. Since I apply the flotation cost to the entire DCF result, I have utilized an adjustment factor that is approximately one half of the 3.9% as measured on

Attachment PRM-11. Hence, my flotation cost adjustment factor is 1.02, which is used on page 2 of Attachment PRM-1.

RISK PREMIUM ANALYSIS

Q: Please describe your use of the risk premium approach to determine the cost of equity.

A: With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Attachment PRM-1. That result is 12.00% prior to flotation cost and 12.19% after flotation costs. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

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

A: In my opinion, a 5.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

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

A: I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on February 1, 2013, and a yield spread of 1.50%, derived from historical data.

Q. What historical data have you analyzed?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt and are shown on page 1 of Attachment PRM-12. For the twelve months ended February 2013, the average monthly yield on Moody's index of A-rated public utility bonds was 4.10%. For the six and three-month periods ended February 2013, the yields were 4.02% and 4.11%, respectively. During the twelve-months ended February 2013, the range of the yields on A-rated public utility bonds was 3.84% to 4.48%. Page 2 of Attachment PRM-12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Attachment PRM-12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.55% on a twelve-month average basis, 1.46% on a six-month average basis, and 1.47% on a the three-month average basis. From these averages, 1.50% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2013	First	3.7%	4.7%	3.0%	1.50%	4.50%
2013	Second	3.8%	4.8%	3.1%	1.50%	4.60%
2013	Third	3.8%	4.9%	3.2%	1.50%	4.70%
2013	Fourth	3.9%	4.9%	3.3%	1.50%	4.80%
2014	First	4.1%	5.1%	3.4%	1.50%	4.90%
2014	Second	4.2%	5.2%	3.5%	1.50%	5.00%

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

A: Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2012 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	30-Year	Corporate	
Averages	Treasury	Aaa-rated	Baa-rated
2014-18	4.7%	5.4%	6.4%
2019-23	5.5%	6.1%	7.1%

Given these forecasted interest rates, a 5.00% yield on A-rated public utility bonds represents a reasonable expectation.

Q: What equity risk premium have you determined for this case?

A: To develop an appropriate equity risk premium, I analyzed the results from the 2013 Classic Yearbook for Stocks, Bonds, Bills and Inflation ("SBBI") published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Attachment PRM-13.

Common Equity Risk Premiums

Low Interest Rates	7.00%
Average Across All Interest Rates	5.40%
High Interest Rates	3.77%

Based on my analysis of the historical data, the equity risk premium was 7.00% when the marginal cost of long-term government bonds was low (i.e., 3.03%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.35% on average during periods of high interest rates) the spread narrowed to 3.77%. Over the entire spectrum of interest rates, the equity risk premium was 5.40% when the average government bond yield was 5.16%. With the current low interest rates, an equity risk premium of 7.00% is indicated today.

CAPITAL ASSET PRICING MODEL

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

A: The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The result of the CAPM is 10.91% prior to flotation costs and 11.10% after flotation costs as shown on page 2 of Attachment PRM-1. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q: What betas have you considered in the CAPM?

A: For my CAPM analysis, I initially considered the Value Line betas. As shown on Attachment PRM-10, the average beta is 0.66 for the Gas Group.

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

A: The betas must be reflective of the financial risk associated with the rate setting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[9] as follows:

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

where βl = the leveraged beta, βu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and, therefore, are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.48 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Attachment PRM-10 under the category "Hamada" who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.73 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of

[9]Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452

equity is 0.73 for the Gas Group.

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

A: As shown on page 1 of Attachment PRM-14, I provided the historical yields on Treasury notes and bonds. For the twelve months ended February 2013, the average yield on 30-year Treasury bonds was 2.93%. For the six- and three-months ended February 2013, the yields on 30-year Treasury bonds were 2.95% and 3.04%, respectively. During the twelve-months ended February 2013, the range of the yields on 30-year Treasury bonds was 2.59% to 3.28%. The recent low yields on Treasury bonds can be traced to events that have occurred during the past several years that included the financial crisis and its aftermath. The resulting decline in the yields on Treasury obligations can be attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that has been expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist").

Essentially, low interest rates are the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. As shown on page 2 of Attachment PRM-14, forecasts published by Blue Chip on February 1, 2013 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.5% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.7% from 2014 through 2018 and 5.5% from 2019 to 2023. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.50% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

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

A: As shown in the lower panel of data presented on page 2 of Attachment PRM-14, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Attachment PRM-13. On that schedule, the market return on large stocks during periods of low interest rates was 11.72%. During that time, the yield on long-term government bonds was 3.03%. The resulting market premium is 8.69% (11.72% - 3.03%) based on historical data. For the forecast returns, I calculated a 12.87% total market return from the Value Line data and a DCF return of 11.22% for the S&P 500. With the average forecast return of 12.05% (12.87% + 11.22% = 24.09% ÷ 2), I calculated a market premium of 8.55% (12.05% - 3.50%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 8.62% (8.55% + 8.69% = 17.24% ÷ 2).

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

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the

CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,201 million, as shown on Attachment PRM-10. For my CAPM analysis, I have adopted the mid-cap adjustment of 1.12%, as revealed on page 3 of Attachment PRM-14.

COMPARABLE EARNINGS

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

A: The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

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

Bluefield Water Works vs. Public Service Commission, 262 U.S.

668 (1923).

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

Q: How have you implemented the Comparable Earnings approach?

A: In order to implement the Comparable Earnings approach, non-regulated companies were selected from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Attachment PRM-15.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-15, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

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

A: I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 12.4% using only the returns that were less than 20% as shown on page 2 of Attachment PRM-15. The forecast rates of return as published by Value Line are shown by the 13.3% also using values less than 20%, as provided on page 2 of Attachment PRM-15. Using these data my Comparable Earnings result is 12.85%, as shown on page 2 of Attachment PRM-1.

CONCLUSION ON COST OF EQUITY

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

A: Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable cost of common equity for the Company is 11.25%. My cost of equity recommendation is obtained from a range of results and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q: Does this complete your direct testimony?

A: Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

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

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies.

While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-

2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

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

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Paul R. Moul, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Paul R. Moul

Paul R. Moul

STATE OF New Jersey

COUNTY OF Camden

SUBSCRIBED AND SWORN to before me by Paul R. Moul on this the 21st day of May, 2013.

Judy Marie Tucker

Notary Public

My Commission expires: 5-12-2014

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

ATTACHMENTS TO ACCOMPANY THE TESTIMONY OF PAUL R. MOUL ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

Columbia Gas of Kentucky, Inc.
Index of Attachments

Columbia Gas of Kentucky, Inc.
Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.49%	5.68%	2.70%
Short-Term Debt	0.28%	1.94%	0.01%
Total Debt	47.77%		2.71%
Common Equity	52.23%	11.25%	5.88%
Total	100.00%		8.59%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 35.0000% income tax rate
(11.76% ÷ 2.71%) 4.34 x

Post-tax coverage of interest expense
(8.59% ÷ 2.71%) 3.17 x

Columbia Gas of Kentucky, Inc.
Cost of Equity
as of February 28, 2013

Discounted Cash Flow (DCF)	***D_1/P_0*** [1]	+	***g*** [2]	+	***lev.*** [3]	=	***k***	***x***	***flot.*** [4]	=	***k***				
Gas Group	3.92%	+	5.00%	+	0.57%	=	9.49%	x	1.02	=	9.68%				
Risk Premium (RP)	***I*** [5]	+	***RP*** [6]	=	***k***	+	**flot.**	=	***k***						
Gas Group	5.00%	+	7.00%	=	12.00%	+	0.19%	=	12.19%						
Capital Asset Pricing Model (CAPM)	***Rf*** [7]	+	***ß*** [8]	***x (***	***Rm-Rf*** [9]	***) +***	***size*** [10]	=	***k***	+	**flot.**	=	***k***		
Gas Group	3.50%	+	0.73	x (	8.62%	) +	1.12%	=	10.91%	+	0.19%	=	11.10%		
Comparable Earnings (CE)	***Historical*** [11]		***Forecast*** [11]		**Average**										
Comparable Earnings Group	12.4%		13.3%		12.85%										

References
(1) Attachment PRM-7 page 1
(2) Attachment PRM-9 page 1
(3) Attachment PRM-10 page 1
(4) Attachment PRM-11 page 1
(5) A-rated public utility bond yield comprised of a 3.50% risk-free rate of return (Attachment PRM-14 page 2) and a yield spread of 1.50% (Attachment PRM-12 page 3)
(6) Attachment PRM-13 page 1
(7) Attachment PRM-14 pages 1 & 2
(8) Attachment PRM-10 page 1
(9) Attachment PRM-14 page 2
(10) Attachment PRM-14 page 3
(11) Attachment PRM-15 page 2

Columbia Gas of Kentucky, Inc.
Capitalization and Financial Statistics
2008-2012, Inclusive

	2012	2011	2010	2009	2008	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 173.9	$ 172.4	$ 171.5	$ 160.7	$ 167.5	
Short-Term Debt	$ -	$ -	$ -	$ -	$ 15.6	
Total Capital	$ 173.9	$ 172.4	$ 171.5	$ 160.7	$ 183.1	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	47.2%	47.6%	47.9%	44.8%	43.0%	46.1%
Common Equity [1]	52.8%	52.4%	52.1%	55.2%	57.0%	53.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	47.2%	47.6%	47.9%	44.8%	47.9%	47.1%
Common Equity [1]	52.8%	52.4%	52.1%	55.2%	52.1%	52.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	9.3%	12.1%	12.0%	8.9%	10.6%	10.6%
Operating Ratio [2]	84.5%	86.8%	87.4%	91.1%	91.7%	88.3%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	3.83 x	4.61 x	5.01 x	4.10 x	5.52 x	4.61 x
Post-tax: All Interest Charges	2.79 x	3.25 x	3.52 x	2.93 x	3.78 x	3.25 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	3.82 x	4.60 x	5.01 x	4.10 x	5.51 x	4.61 x
Post-tax: All Interest Charges	2.78 x	3.24 x	3.51 x	2.92 x	3.77 x	3.24 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.5%	0.2%	0.3%	0.3%	0.3%	0.3%
Effective Income Tax Rate	36.8%	37.6%	37.2%	37.9%	38.5%	37.6%
Internal Cash Generation/Construction [4]	80.9%	93.3%	87.8%	34.3%	37.1%	66.7%
Gross Cash Flow/ Avg. Total Debt [5]	27.9%	29.3%	25.0%	24.6%	30.6%	27.5%
Gross Cash Flow Interest Coverage [6]	5.81 x	5.98 x	5.53 x	5.60 x	6.91 x	5.97 x

See Page 2 for Notes.

Columbia Gas of Kentucky, Inc.
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: FERC Form 2

Gas Group
Capitalization and Financial Statistics [1]
2008-2012, Inclusive

	2012	2011	2010	2009	2008	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,591.7	$ 2,490.8	$ 2,079.2	$ 2,050.6	$ 1,964.5	
Short-Term Debt	$ 378.9	$ 285.4	$ 220.7	$ 192.9	$ 311.5	
Total Capital	$ 2,970.6	$ 2,776.2	$ 2,299.9	$ 2,243.5	$ 2,276.0	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	17 x	15 x	14 x	15 x	16 x
Market/Book Ratio	179.1%	182.7%	174.8%	163.2%	171.9%	174.3%
Dividend Yield	3.7%	3.8%	3.9%	4.2%	4.0%	3.9%
Dividend Payout Ratio	64.0%	63.6%	58.1%	58.3%	57.1%	60.2%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	43.8%	43.1%	44.1%	45.0%	45.7%	44.3%
Preferred Stock	0.2%	0.2%	0.2%	0.3%	0.3%	0.2%
Common Equity [2]	56.0%	56.7%	55.7%	54.7%	54.0%	55.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	50.4%	48.6%	50.0%	50.6%	53.7%	50.7%
Preferred Stock	0.2%	0.2%	0.2%	0.3%	0.2%	0.2%
Common Equity [2]	49.4%	51.3%	49.8%	49.2%	46.0%	49.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.2%	10.4%	11.5%	10.3%	11.9%	10.9%
Operating Ratio [3]	86.5%	87.4%	87.8%	88.9%	89.8%	88.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.66 x	4.63 x	4.89 x	4.15 x	4.40 x	4.55 x
Post-tax: All Interest Charges	3.57 x	3.41 x	3.47 x	3.00 x	3.12 x	3.31 x
Overall Coverage: All Int. & Pfd. Div.	3.55 x	3.40 x	3.46 x	2.99 x	3.11 x	3.30 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.56 x	4.58 x	4.84 x	4.11 x	4.37 x	4.49 x
Post-tax: All Interest Charges	3.46 x	3.36 x	3.43 x	2.97 x	3.09 x	3.26 x
Overall Coverage: All Int. & Pfd. Div.	3.44 x	3.35 x	3.41 x	2.95 x	3.08 x	3.25 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	4.1%	2.1%	1.5%	2.1%	1.6%	2.3%
Effective Income Tax Rate	30.9%	35.0%	36.6%	35.3%	37.7%	35.1%
Internal Cash Generation/Construction [5]	70.4%	94.7%	116.1%	111.3%	108.0%	100.1%
Gross Cash Flow/ Avg. Total Debt [6]	25.8%	26.8%	28.2%	22.4%	21.0%	24.8%
Gross Cash Flow Interest Coverage [7]	6.80 x	6.47 x	6.79 x	5.73 x	5.06 x	6.17 x
Common Dividend Coverage [8]	4.13 x	4.16 x	4.50 x	4.00 x	3.94 x	4.15 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

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

Basis of Selection:
The Delivery Group includes companies that are contained in The Value Line Investment Survey within the industry group "Natural Gas Utility," they are not currently the target of a publicly-announced merger or acquisition, and after eliminating NiSource due to its electric and natural gas pipeline/storage operations and UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
AGL	AGL Resources, Inc.	A3	BBB+	NYSE	A	0.75
ATO	Atmos Energy Corp.	Baa1	BBB+	NYSE	A-	0.70
LG	Laclede Group	Baa1	A	NYSE	B+	0.55
NJR	New Jersey Resources Corp.	Aa3	A	NYSE	B+	0.65
NWN	Northwest Natural Gas	A3	A+	NYSE	A-	0.55
PNY	Piedmont Natural Gas Co.	A3	A	NYSE	A	0.65
SJI	South Jersey Industries, Inc.	Baa1	BBB+	NYSE	A-	0.65
SWX	Southwest Gas Corporation	Baa2	BBB	NYSE	B+	0.75
WGL	WGL Holdings, Inc.	A2	A+	NYSE	B+	0.65
	Average	A3	A-		A-	0.66

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2008-2012, Inclusive

	2012	2011	2010 (Millions of Dollars)	2009	2008	Average
Amount of Capital Employed						
Permanent Capital	$ 21,620.0	$ 18,840.8	$ 17,587.3	$ 16,618.6	$ 15,620.1	
Short-Term Debt	$ 648.9	$ 531.4	$ 435.4	$ 415.0	$ 803.5	
Total Capital	$ 22,268.9	$ 19,372.2	$ 18,022.7	$ 17,033.6	$ 16,423.6	
Market-Based Financial Ratios						
Price-Earnings Multiple	18 x	15 x	15 x	14 x	14 x	15 x
Market/Book Ratio	164.0%	155.2%	142.8%	137.1%	174.9%	154.8%
Dividend Yield	4.1%	4.4%	4.8%	5.2%	4.3%	4.6%
Dividend Payout Ratio	70.3%	64.7%	72.0%	72.2%	61.9%	68.2%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.9%	52.9%	53.4%	54.2%	54.3%	53.5%
Preferred Stock	1.6%	1.3%	1.3%	1.5%	1.7%	1.5%
Common Equity [2]	45.5%	45.8%	45.3%	44.3%	44.0%	45.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.5%	54.5%	54.7%	55.6%	57.1%	55.3%
Preferred Stock	1.6%	1.3%	1.3%	1.4%	1.6%	1.4%
Common Equity [2]	44.0%	44.3%	44.0%	43.0%	41.3%	43.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.2%	10.5%	10.8%	10.1%	12.2%	10.6%
Operating Ratio [3]	81.3%	81.4%	81.6%	83.0%	84.1%	82.3%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.94 x	3.35 x	3.34 x	3.06 x	3.39 x	3.22 x
Post-tax: All Interest Charges	2.35 x	2.59 x	2.52 x	2.36 x	2.57 x	2.48 x
Overall Coverage: All Int. & Pfd. Div.	2.32 x	2.57 x	2.50 x	2.33 x	2.53 x	2.45 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.85 x	3.25 x	3.25 x	2.96 x	3.28 x	3.12 x
Post-tax: All Interest Charges	2.25 x	2.49 x	2.43 x	2.26 x	2.46 x	2.38 x
Overall Coverage: All Int. & Pfd. Div.	2.22 x	2.47 x	2.41 x	2.22 x	2.42 x	2.35 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	5.7%	6.6%	7.8%	7.7%	7.0%
Effective Income Tax Rate	26.2%	36.8%	34.3%	31.8%	33.8%	32.6%
Internal Cash Generation/Construction [5]	75.0%	89.4%	108.0%	100.0%	83.1%	91.1%
Gross Cash Flow/ Avg. Total Debt [6]	21.9%	23.2%	23.9%	22.5%	22.6%	22.8%
Gross Cash Flow Interest Coverage [7]	5.37 x	5.12 x	5.09 x	4.85 x	4.75 x	5.04 x
Common Dividend Coverage [8]	4.31 x	4.58 x	4.88 x	4.73 x	4.95 x	4.69 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

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

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

	Ticker	Credit Rating (1) Moody's	Credit Rating (1) S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AGL Resources Inc.	GAS	A3	BBB+	NYSE	A	0.75
Ameren Corporation	AEE	Baa2	BBB	NYSE	B	0.80
American Electric Power	AEP	Baa2	BBB	NYSE	B	0.70
CMS Energy	CMS	Baa1	BBB	NYSE	B	0.75
CenterPoint Energy	CNP	Baa2	BBB+	NYSE	B	0.80
Consolidated Edison	ED	A3	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A3	BBB+	NYSE	B+	0.75
Dominion Resources	D	A3	A-	NYSE	B+	0.65
Duke Energy	DUK	A3	BBB+	NYSE	B	0.60
Edison Int'l	EIX	A3	BBB+	NYSE	B	0.75
Entergy Corp.	ETR	Baa2	BBB	NYSE	A+	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.15
Exelon Corp.	EXC	A3	BBB	NYSE	B+	0.80
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	A-	0.80
Integrys Energy Group	TEG	A2	A-	NYSE	B	0.90
NextEra Energy Inc.	NEE	A2	A-	NYSE	A	0.75
NiSource Inc.	NI	Baa2	BBB-	NYSE	B	0.85
Northeast Utilities	NU	Baa2	A-	NYSE	B	0.70
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	NR	1.10
ONEOK, Inc.	OKE	Baa2	BBB	NYSE	NR	0.95
PEPCO Holdings, Inc.	POM	Baa2	BBB+	NYSE	B	0.75
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.55
PPL Corp.	PPL	Baa2	BBB	NYSE	B+	0.65
Pinnacle West Capital	PNW	Baa1	BBB+	NYSE	B	0.70
Public Serv. Enterprise Inc.	PEG	A3	BBB	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.65
Sempra Energy	SRE	A2	A	NYSE	A-	0.80
Southern Co.	SO	A3	A	NYSE	A-	0.55
TECO Energy	TE	A3	BBB+	NYSE	B	0.85
Wisconsin Energy Corp.	WEC	A2	A-	NYSE	A	0.65
Xcel Energy Inc	XEL	A3	A-	NYSE	B+	0.65
Average for S&P Utilities		Baa1	BBB+		A	0.75

Note: (1) Ratings are those of utility subsidiaries

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

Columbia Gas of Kentucky, Inc.
Investor-provided Capitalization
Actual at February 28, 2013 and Projected at August 30, 2013 and December 31, 2014

	Actual at February 28, 2013		Projected at August 30, 2013		Projected at Dec. 31, 2014		Thirteen-month Average December 31, 2014	
	Amount Outstanding	Ratios	Amount Outstanding ($000's)	Ratios	Amount Outstanding ($000's)	Ratios	Amount Outstanding ($000's)	Ratios
Long Term Debt	$ 87,335,000	47.40%	$ 87,335,000	47.67%	$ 96,335,000	47.34%	$ 94,642,692	47.49%
Common Stock Equity								
Common Stock	23,806,202		23,806,202		23,806,202		23,806,202	
Additional Paid in Capital	5,582,722		5,582,722		5,582,722		5,582,722	
Retained Earnings	67,542,194		66,465,000		77,218,000		74,692,615	
Total Common Equity	96,931,118	52.60%	95,853,924	52.33%	106,606,924	52.39%	104,081,539	52.23%
Total Permanent Capital	184,266,118	100.00%	183,188,924	100.00%	202,941,924	99.73%	198,724,231	99.72%
Short Term Debt (1)	-	0.00%	-	0.00%	552,462	0.27%	552,462	0.28%
Total Capital Employed	$ 184,266,118	100.00%	$ 183,188,924	100.00%	$ 203,494,386	100.00%	$ 199,276,693	100.00%

Note: (1) Thirteen month average.

Source of information: Company provided data

Columbia Gas of Kentucky, Inc.
Long-term Debt Outstanding
Actual at February 28, 2013 and Projected at August 30, 2013 and December 31, 2014

Date of Issuance	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
January 5, 2006	January 5, 2016	5.41%	$ 10,750,000	$ 581,575	
January 5, 2006	January 5, 2017	5.45%	4,210,000	229,445	
January 5, 2006	January 5, 2026	5.92%	12,375,000	732,600	
November 1, 2006	November 1, 2021	6.015%	16,000,000	962,400	
December 23, 2008	December 23, 2013	5.53%	14,000,000	774,200	
December 16, 2010	December 16, 2030	6.02%	10,000,000	602,000	
January 7, 2013	January 7, 2043	5.77%	20,000,000	1,154,000	
Long-Term Debt at Feb. 28, 2013 and August 30, 2013			87,335,000	5,036,220	5.77%
December 23, 2008	December 23, 2013	5.53%	(14,000,000)	(774,200)	
December 18, 2013	December 18, 2043	5.24%	21,000,000	1,100,400	
November 30, 2014	November 30, 2014	5.28%	2,000,000	105,600	
Long-Term Debt at December 31, 2014			$ 96,335,000	$ 5,468,020	5.68%

Source of information: Company provided data

Columbia Gas of Kentucky, Inc.
Long-term Debt Outstanding
Thirteen-month Average December 31, 2014

Date of Issuance	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
January 5, 2006	January 5, 2016	5.41%	$ 10,750,000	$ 581,575	
January 5, 2006	January 5, 2017	5.45%	4,210,000	229,445	
January 5, 2006	January 5, 2026	5.92%	12,375,000	732,600	
November 1, 2006	November 1, 2021	6.015%	16,000,000	962,400	
December 16, 2010	December 16, 2030	6.02%	10,000,000	602,000	
January 7, 2013	January 7, 2043	5.77%	20,000,000	1,154,000	
December 18, 2013	December 18, 2043	5.24%	21,000,000	1,100,400	
November 30, 2014	November 30, 2014	5.28%	307,692	16,246	
Thirteen-month Average Long-Term Debt			$ 94,642,692	$ 5,378,666	5.68%

Source of information: Company provided data

Monthly Dividend Yields for
Delivery Group
for the Twelve Months Ending February 2013

Company	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	12-Month Average	6-Month Average	3-Month Average
AGL RES INC (NYSE:GAS)	4.72%	4.71%	4.92%	4.78%	4.59%	4.65%	4.52%	4.55%	4.73%	4.63%	4.54%	4.71%			
ATMOS ENERGY CORP (NYSE:ATO)	4.41%	4.27%	4.17%	3.95%	3.88%	3.95%	3.87%	3.92%	4.00%	4.00%	3.77%	3.67%			
LACLEDE GROUP INC (NYSE:LG)	4.27%	4.24%	4.40%	4.18%	4.00%	3.97%	3.87%	4.11%	4.22%	4.42%	4.29%	4.21%			
NEW JERSEY RES (NYSE:NJR)	3.42%	3.53%	3.65%	3.49%	3.50%	3.60%	3.50%	3.61%	3.97%	4.05%	3.83%	3.62%			
NORTHWEST NAT GAS CO (NYSE:NWN)	3.95%	3.90%	3.85%	3.76%	3.66%	3.63%	3.64%	3.91%	4.16%	4.15%	4.01%	4.01%			
PIEDMONT NAT GAS INC (NYSE:PNY)	3.87%	3.95%	3.99%	3.73%	3.79%	3.87%	3.70%	3.78%	3.92%	3.84%	3.92%	3.87%			
SOUTH JERSEY INDS INC (NYSE:SJI)	3.22%	3.28%	3.35%	3.17%	3.06%	3.20%	3.05%	3.52%	3.57%	3.53%	3.28%	3.23%			
SOUTHWEST GAS CORPORATION (SWX)	2.49%	2.82%	2.82%	2.71%	2.66%	2.76%	2.68%	2.73%	2.82%	2.79%	2.66%	2.61%			
WGL HLDGS INC (NYSE:WGL)	3.84%	4.00%	4.13%	4.06%	3.97%	4.12%	4.01%	4.03%	4.12%	4.12%	3.83%	3.81%			
Average	3.80%	3.86%	3.92%	3.76%	3.68%	3.75%	3.65%	3.80%	3.95%	3.95%	3.79%	3.75%	3.81%	3.82%	3.83%

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://finance.yahoo.com/
http://www.nasdaq.com/symbol/gas/dividend-history

Forward-looking Dividend Yield					
	½ Growth	D_0/P_0	(.5g)	D_1/P_0	$\frac{D_0(1+g)^0+D_0(1+g)^0+D_0(1+g)^1+D_0(1+g)^1}{P_0}$
		3.82%	1.025000	3.91%	
	Discrete	D_0/P_0	Adj.	D_1/P_0	$\frac{D_0(1+g)^{.25}+D_0(1+g)^{.50}+D_0(1+g)^{.75}+D_0(1+g)^{1.00}}{P_0}$
		3.82%	1.031059	3.93%	
	Quarterly	D_0/P_0	Adj.	D_1/P_0	$\left[\left(1+\frac{D_0(1+g)^{.25}}{P_0}\right)^4-1\right]$
		0.9538%	1.012272	3.92%	
	Average			3.92%	
	Growth rate			5.00%	
	K			8.92%	

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Gas Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
AGL Resources, Inc.	4.50%	9.00%	7.50%	5.00%	5.50%	7.00%	6.00%	6.50%
Atmos Energy Corp.	4.00%	7.00%	1.50%	1.50%	4.50%	6.50%	4.50%	4.50%
Laclede Group	6.00%	6.50%	2.50%	1.50%	6.50%	5.00%	7.00%	5.00%
New Jersey Resources Corp.	7.00%	7.50%	8.00%	6.00%	7.50%	8.00%	4.50%	5.00%
Northwest Natural Gas	4.50%	4.00%	4.50%	3.00%	4.00%	4.00%	3.50%	3.00%
Piedmont Natural Gas Co.	4.50%	5.00%	4.00%	4.50%	3.00%	5.00%	4.00%	5.50%
South Jersey Industries, Inc.	7.00%	9.50%	9.50%	6.50%	7.00%	10.50%	8.00%	8.00%
Southwest Gas Corp.	6.50%	6.00%	4.00%	2.00%	5.00%	4.50%	3.00%	3.50%
WGL Holdings, Inc.	3.00%	3.00%	2.50%	2.00%	5.00%	4.00%	1.50%	3.00%
Average	5.22%	6.39%	4.89%	3.56%	5.33%	6.06%	4.67%	4.89%

Source of Information: Value Line Investment Survey, December 7, 2012

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	I/B/E/S First Call	SNL	Zacks	Morningstar	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
AGL Resources, Inc.	NMF	3.80%	3.50%	4.60%	6.00%	1.50%	5.00%	9.00%	6.50%
Atmos Energy Corp.	5.93%	6.60%	6.00%	5.80%	4.00%	1.50%	6.00%	3.50%	3.50%
Laclede Group	5.30%	4.00%	3.00%	-	3.00%	2.50%	4.50%	2.50%	4.50%
New Jersey Resources Corp.	4.00%	1.10%	4.00%	2.60%	5.50%	4.00%	5.50%	5.00%	7.50%
Northwest Natural Gas	4.50%	3.80%	4.20%	3.00%	3.00%	2.50%	1.00%	-0.50%	4.00%
Piedmont Natural Gas Co.	5.57%	4.00%	3.70%	4.60%	2.50%	3.50%	1.50%	2.50%	3.50%
South Jersey Industries, Inc.	6.00%	8.00%	6.00%	-	9.00%	9.00%	6.00%	7.00%	7.50%
Southwest Gas Corp.	4.05%	5.50%	4.90%	-	9.00%	8.00%	6.00%	6.50%	6.00%
WGL Holdings, Inc.	5.25%	5.00%	5.30%	5.00%	2.50%	2.50%	4.00%	1.50%	3.50%
Average	5.08%	4.64%	4.51%	4.27%	4.94%	3.89%	4.39%	4.11%	5.17%

Source of Information : Yahoo Finance, February 20, 2013
Reuters.com, February 20, 2013
Zacks, February 20, 2013
Morningstar, February 20, 2013
Value Line Investment Survey, December 7, 2012

Gas Group
Financial Risk Adjustment

		AGL Resources (NYSE:GAS)	ATMOS Energy (NYSE:ATO)	Laclede Group (NYSE:LG)	New Jersey Resources (NYSE:NJR)	Northwest Natural Gas (NYSE:NWN)	Piedmont Natural Gas (NYSE:PNY)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	WGL Holdings (NYSE:WGL)	Average
Fiscal Year		12/31/12	09/30/12	09/30/12	09/30/12	12/31/12	10/31/12	12/31/12	12/31/12	09/30/12	
Capitalization at Fair Values											
	Debt(D)	4,057,000	2,426,434	452,768	583,140	834,664	1,163,227	682,300	1,482,095	758,900	1,382,281
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	4,710,667	3,229,686	969,196	1,776,495	1,189,731	2,302,608	1,593,109	1,957,128	2,077,369	2,200,665
	Total	8,767,667	5,656,120	1,421,964	2,359,635	2,024,395	3,465,835	2,275,409	3,439,223	2,864,442	3,586,077
Capital Structure Ratios											
	Debt(D)	46.27%	42.90%	31.84%	24.71%	41.23%	33.56%	29.99%	43.09%	26.49%	35.56%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.98%	0.11%
	Equity(E)	53.73%	57.10%	68.16%	75.29%	58.77%	66.44%	70.01%	56.91%	72.52%	64.33%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%
Common Stock											
	Issued	117,855.075	90,239.900	22,539.431	41,619.633	26,917.000	72,250.000		46,147.788	51,611.647	
	Treasury	0.000	0.000	0.000	2,763.659	0.000	0.000		0.000	0.000	
	Outstanding	117,855.075	90,239.900	22,539.431	38,855.974	26,917.000	72,250.000	31,653.262	46,147.788	51,611.647	
	Market Price	$ 39.97	$ 35.79	$ 43.00	$ 45.72	$ 44.20	$ 31.87	$ 50.33	$ 42.41	$ 40.25	
Capitalization at Carrying Amounts											
	Debt(D)	3,553,000	1,960,131	364,416	532,929	691,700	975,000	626,400	1,318,510	589,200	1,179,032
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	3,413,000	2,359,243	601,611	813,865	733,033	1,027,004	736,214	1,310,179	1,269,556	1,362,634
	Total	6,966,000	4,319,374	966,027	1,346,794	1,424,733	2,002,004	1,362,614	2,628,689	1,886,929	2,544,796
Capital Structure Ratios											
	Debt(D)	51.00%	45.38%	37.72%	39.57%	48.55%	48.70%	45.97%	50.16%	31.23%	44.25%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.49%	0.17%
	Equity(E)	49.00%	54.62%	62.28%	60.43%	51.45%	51.30%	54.03%	49.84%	67.28%	55.58%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.75	0.70	0.55	0.65	0.55	0.65	0.65	0.75	0.65	0.66

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.66	=	Bu	[1+	(1-0.35)	0.5528	+	0.0017	]
	0.66	=	Bu	[1+	0.65	0.5528	+	0.0017	]
	0.66	=	Bu	1.3610					
	0.48	=	Bu						

Hamada	Bl	=	0.48	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.48	[1+	0.65	0.7962	+	0.0030	]
	Bl	=	0.48	1.5205					
	Bl	=	0.73						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	) - (	ku	-	d	)	P	/	E
	7.62%	=	8.92%	-	(((	7.62%	-	4.02%	)	0.65	)	35.56%	/	64.33%	) - (	7.62%	-	5.68%	)	0.11%	/	64.33%
	7.62%	=	8.92%	-	(((	3.60%			)	0.65	)	0.5528			) - (	1.94%			)	0.0017		
	7.62%	=	8.92%	-	((	2.34%					)	0.5528			) - (	1.94%			)	0.0017		
	7.62%	=	8.92%	-		1.29%									-	0.00%						

M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	) + (	ku	-	d	)	P	/	E
	9.49%	=	7.62%	+	(((	7.62%	-	4.02%	)	0.65	)	44.25%	/	55.58%	) + (	7.62%	-	5.68%	)	0.17%	/	55.58%
	9.49%	=	7.62%	+	(((	3.60%			)	0.65	)	0.7962			) + (	1.94%			)	0.0030		
	9.49%	=	7.62%	+	((	2.34%					)	0.7962			) + (	1.94%			)	0.0030		
	9.49%	=	7.62%	+		1.86%									+	0.01%						

Gas Group

Analysis of Public Offerings of Common Stock

Company	Date of Offering	No. of shares offered	Dollar amount of offering	Price to public	Underwriters' discount and commission	Gross Proceeds per share	Estimated company issuance expenses	Net proceeds per share	Percent of offering price: Underwriters' discount and commission	Percent of offering price: Estimated company issuance expenses	Percent of offering price: Total issuance and selling expense
Piedmont Natural Gas Company, Inc.	01/29/13	4,000,000	$ 128,000,000	$ 32.00	$ 1.120	$ 30.880	$ 0.088	$ 30.792	3.5%	0.3%	3.8%
Atmos Energy Corporation	12/07/06	5,500,000	$ 173,250,000	$ 31.50	$ 1.103	$ 30.398	$ 0.073	$ 30.325	3.5%	0.2%	3.7%
AGL Resources Inc	11/19/04	9,600,000	$ 297,696,000	$ 31.01	$ 0.930	$ 30.080	$ 0.042	$ 30.038	3.0%	0.1%	3.1%
Atmos Energy Corporation	10/21/04	14,000,000	$ 346,500,000	$ 24.75	$ 0.990	$ 23.760	$ 0.029	$ 23.731	4.0%	0.1%	4.1%
Atmos Energy Corporation	07/19/04	8,650,000	$ 214,087,500	$ 24.75	$ 0.990	$ 23.760	$ 0.046	$ 23.714	4.0%	0.2%	4.2%
The Laclede Group, Inc.	05/25/04	1,500,000	$ 40,200,000	$ 26.80	$ 0.871	$ 25.929	$ 0.067	$ 25.862	3.3%	0.3%	3.6%
Northwest Natural Gas Company	03/30/04	1,200,000	$ 37,200,000	$ 31.00	$ 1.010	$ 29.99	$ 0.146	$ 29.844	3.3%	0.5%	3.8%
Piedmont Natural Gas Company, Inc.	01/23/04	4,250,000	$ 180,625,000	$ 42.50	$ 1.490	$ 41.010	$ 0.082	$ 40.928	3.5%	0.2%	3.7%
Atmos Energy Corporation	06/18/03	4,000,000	$ 101,240,000	$ 25.31	$ 1.0124	$ 24.298	$ 0.095	$ 24.203	4.0%	0.4%	4.4%
AGL Resources Inc.	02/11/03	5,600,000	$ 123,200,000	$ 22.00	$ 0.770	$ 21.230	$ 0.045	$ 21.185	3.5%	0.2%	3.7%
WGL Holdings, Inc	06/26/01	1,790,000	$ 47,846,700	$ 26.73	$ 0.895	$ 25.835	$ 0.031	$ 25.804	3.3%	0.1%	3.4%
Atmos Energy Corporation	11/07/00	6,000,000	$ 133,500,000	$ 22.25	$ 1.110	$ 21.140	$ 0.058	$ 21.082	5.0%	0.3%	5.3%
Average									3.7%	0.2%	3.9%

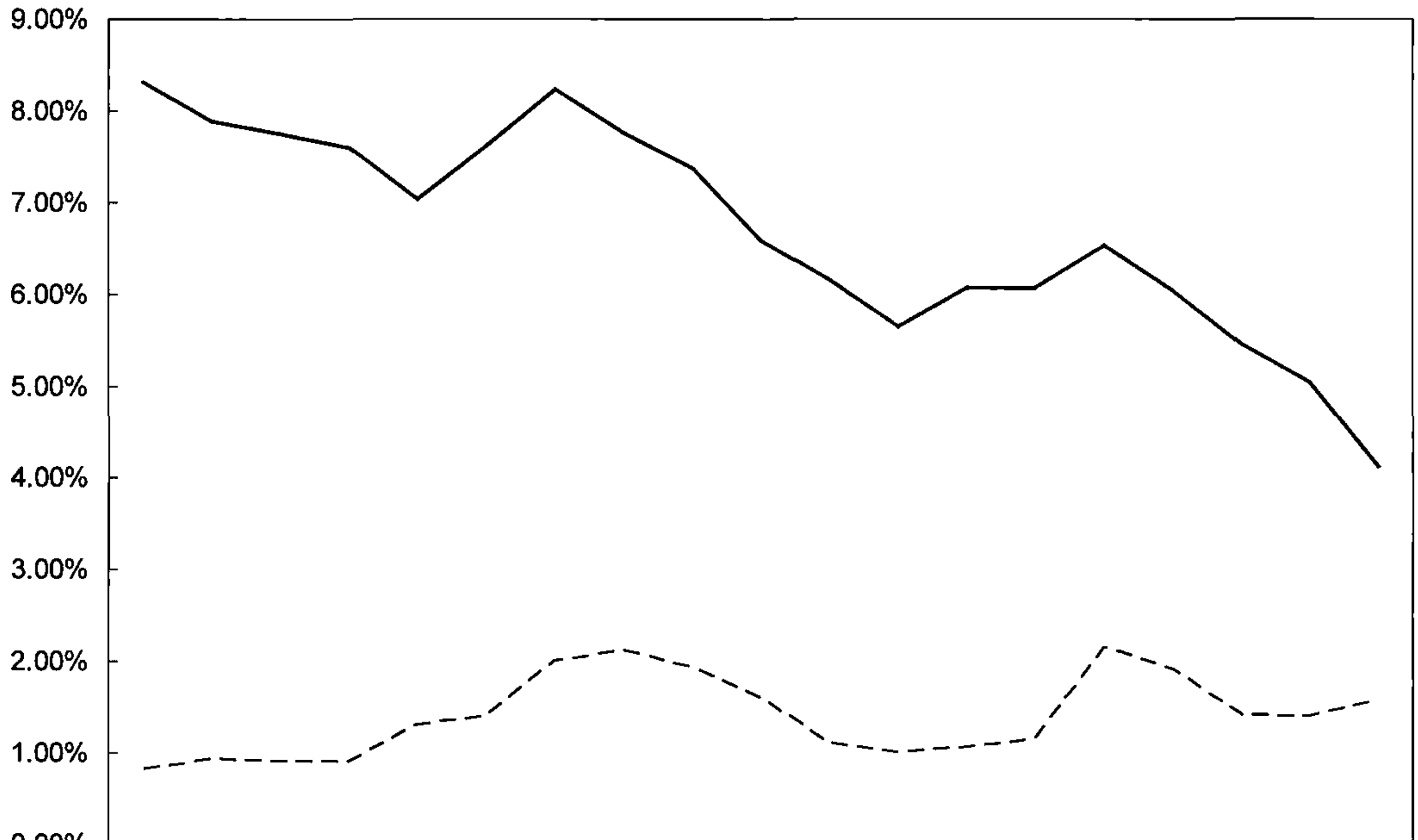
Source of Information: SNL Financial and SEC filings

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2008-2012
and the Twelve Months Ended February 2013

Years	Aa Rated	A Rated	Baa Rated	Average
2008	6.18%	6.53%	7.24%	6.65%
2009	5.75%	6.04%	7.06%	6.28%
2010	5.24%	5.46%	5.96%	5.55%
2011	4.78%	5.04%	5.57%	5.13%
2012	3.83%	4.13%	4.86%	4.27%
Five-Year Average	5.16%	5.44%	6.14%	5.58%
Months				
Mar-12	4.16%	4.48%	5.13%	4.59%
Apr-12	4.10%	4.40%	5.11%	4.53%
May-12	3.92%	4.20%	4.97%	4.36%
Jun-12	3.79%	4.08%	4.91%	4.26%
Jul-12	3.58%	3.93%	4.85%	4.12%
Aug-12	3.65%	4.00%	4.88%	4.18%
Sep-12	3.69%	4.02%	4.81%	4.17%
Oct-12	3.68%	3.91%	4.54%	4.04%
Nov-12	3.60%	3.84%	4.42%	3.95%
Dec-12	3.75%	4.00%	4.56%	4.10%
Jan-13	3.90%	4.15%	4.66%	4.24%
Feb-13	3.95%	4.18%	4.74%	4.29%
Twelve-Month Average	3.81%	4.10%	4.80%	4.24%
Six-Month Average	3.76%	4.02%	4.62%	4.13%
Three-Month Average	3.87%	4.11%	4.65%	4.21%

Source: Mergent Bond Record

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



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%	6.07%	6.53%	6.04%	5.46%	5.04%	4.13%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%	1.08%	1.16%	2.17%	1.93%	1.43%	1.42%	1.59%

A rated Public Utility Bonds over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%
Feb-06	5.82%	4.73%	1.09%
Mar-06	5.98%	4.91%	1.07%
Apr-06	6.29%	5.22%	1.07%
May-06	6.42%	5.35%	1.07%
Jun-06	6.40%	5.29%	1.11%
Jul-06	6.37%	5.25%	1.12%
Aug-06	6.20%	5.08%	1.12%
Sep-06	6.00%	4.93%	1.07%
Oct-06	5.98%	4.94%	1.04%
Nov-06	5.80%	4.78%	1.02%
Dec-06	5.81%	4.78%	1.03%
Jan-07	5.96%	4.95%	1.01%
Feb-07	5.90%	4.93%	0.97%
Mar-07	5.85%	4.81%	1.04%
Apr-07	5.97%	4.95%	1.02%
May-07	5.99%	4.98%	1.01%
Jun-07	6.30%	5.29%	1.01%
Jul-07	6.25%	5.19%	1.06%
Aug-07	6.24%	5.00%	1.24%
Sep-07	6.18%	4.84%	1.34%
Oct-07	6.11%	4.83%	1.28%
Nov-07	5.97%	4.56%	1.41%
Dec-07	6.16%	4.57%	1.59%
Jan-08	6.02%	4.35%	1.67%
Feb-08	6.21%	4.49%	1.72%
Mar-08	6.21%	4.36%	1.85%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.74%	1.64%
Jul-08	6.40%	4.62%	1.78%
Aug-08	6.37%	4.53%	1.84%
Sep-08	6.49%	4.32%	2.17%
Oct-08	7.56%	4.45%	3.11%
Nov-08	7.60%	4.27%	3.33%
Dec-08	6.52%	3.18%	3.34%

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Jan-09	6.39%	3.46%	2.93%
Feb-09	6.30%	3.83%	2.47%
Mar-09	6.42%	3.78%	2.64%
Apr-09	6.48%	3.84%	2.64%
May-09	6.49%	4.22%	2.27%
Jun-09	6.20%	4.51%	1.69%
Jul-09	5.97%	4.38%	1.59%
Aug-09	5.71%	4.33%	1.38%
Sep-09	5.53%	4.14%	1.39%
Oct-09	5.55%	4.16%	1.39%
Nov-09	5.64%	4.24%	1.40%
Dec-09	5.79%	4.40%	1.39%
Jan-10	5.77%	4.50%	1.27%
Feb-10	5.87%	4.48%	1.39%
Mar-10	5.84%	4.49%	1.35%
Apr-10	5.81%	4.53%	1.28%
May-10	5.50%	4.11%	1.39%
Jun-10	5.46%	3.95%	1.51%
Jul-10	5.26%	3.80%	1.46%
Aug-10	5.01%	3.52%	1.49%
Sep-10	5.01%	3.47%	1.54%
Oct-10	5.10%	3.52%	1.58%
Nov-10	5.37%	3.82%	1.55%
Dec-10	5.56%	4.17%	1.39%
Jan-11	5.57%	4.28%	1.29%
Feb-11	5.68%	4.42%	1.26%
Mar-11	5.56%	4.27%	1.29%
Apr-11	5.55%	4.28%	1.27%
May-11	5.32%	4.02%	1.30%
Jun-11	5.26%	3.91%	1.35%
Jul-11	5.27%	3.95%	1.32%
Aug-11	4.69%	3.24%	1.45%
Sep-11	4.48%	2.83%	1.65%
Oct-11	4.52%	2.87%	1.65%
Nov-11	4.25%	2.72%	1.53%
Dec-11	4.33%	2.67%	1.66%
Jan-12	4.34%	2.70%	1.64%
Feb-12	4.36%	2.75%	1.61%
Mar-12	4.48%	2.94%	1.54%
Apr-12	4.40%	2.82%	1.58%
May-12	4.20%	2.53%	1.67%
Jun-12	4.08%	2.31%	1.77%
Jul-12	3.93%	2.22%	1.71%
Aug-12	4.00%	2.40%	1.60%
Sep-12	4.02%	2.49%	1.53%
Oct-12	3.91%	2.51%	1.40%
Nov-12	3.84%	2.39%	1.45%
Dec-12	4.00%	2.47%	1.53%
Jan-13	4.15%	2.68%	1.47%
Feb-13	4.18%	2.78%	1.40%
Average:			
12-months			1.55%
6-months			1.46%
3-months			1.47%

Common Equity Risk Premiums
Years 1926-2012

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.72%	4.72%	7.00%	3.03%
Average Across All Interest Rates	11.82%	6.41%	5.40%	5.16%
High Interest Rates	11.92%	8.15%	3.77%	7.35%

Source of Information: 2013 Stocks, Bonds, Bills, and Inflation (SBBI) Classis Yearbook

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Stocks vs. Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	-13.17%	1.94%
1945	36.44%	4.08%	32.36%	1.99%
1941	-11.59%	2.73%	-14.32%	2.04%
1949	18.79%	3.31%	15.48%	2.09%
1946	-8.07%	1.72%	-9.79%	2.12%
1950	31.71%	2.12%	29.59%	2.24%
1939	-0.41%	3.97%	-4.38%	2.26%
1948	5.50%	4.14%	1.36%	2.37%
2012	16.00%	10.68%	5.32%	2.41%
1947	5.71%	-2.34%	8.05%	2.43%
1942	20.34%	2.60%	17.74%	2.46%
1944	19.75%	4.73%	15.02%	2.46%
1943	25.90%	2.83%	23.07%	2.48%
2011	2.11%	17.95%	-15.84%	2.48%
1938	31.12%	6.13%	24.99%	2.52%
1936	33.92%	6.74%	27.18%	2.55%
1951	24.02%	-2.69%	26.71%	2.69%
1954	52.62%	5.39%	47.23%	2.72%
1937	-35.03%	2.75%	-37.78%	2.73%
1953	-0.99%	3.41%	-4.40%	2.74%
1935	47.67%	9.61%	38.06%	2.76%
1952	18.37%	3.52%	14.85%	2.79%
1934	-1.44%	13.84%	-15.28%	2.93%
1956	31.56%	0.48%	31.08%	2.95%
2008	-37.00%	8.78%	-45.78%	3.03%
1932	-8.19%	10.82%	-19.01%	3.15%
1927	37.49%	7.44%	30.05%	3.16%
1957	-10.78%	8.71%	-19.49%	3.23%
1930	-24.90%	7.98%	-32.88%	3.30%
1933	53.99%	10.38%	43.61%	3.36%
1928	43.61%	2.84%	40.77%	3.40%
1929	-8.42%	3.27%	-11.69%	3.40%
1956	6.56%	-6.81%	13.37%	3.45%
1926	11.62%	7.37%	4.25%	3.54%
1960	0.47%	9.07%	-8.60%	3.80%
1958	43.36%	-2.22%	45.58%	3.82%
1962	-8.73%	7.95%	-16.68%	3.95%
1931	-43.34%	-1.85%	-41.49%	4.07%
2010	15.06%	12.44%	2.62%	4.14%
1961	26.89%	4.82%	22.07%	4.15%
1963	22.80%	2.19%	20.61%	4.17%
1964	16.48%	4.77%	11.71%	4.23%
1959	11.96%	-0.97%	12.93%	4.47%
1965	12.45%	-0.46%	12.91%	4.50%
2007	5.49%	2.60%	2.89%	4.50%
1966	-10.06%	0.20%	-10.26%	4.55%
2009	26.46%	3.02%	23.44%	4.58%
2005	4.91%	5.87%	-0.96%	4.61%
2002	-22.10%	16.33%	-38.43%	4.84%
2004	10.88%	8.72%	2.16%	4.84%
2006	15.79%	3.24%	12.55%	4.91%
2003	28.68%	5.27%	23.41%	5.11%
1998	28.58%	10.76%	17.82%	5.42%
1967	23.98%	-4.95%	28.93%	5.56%
2000	-9.10%	12.87%	-21.97%	5.58%
2001	-11.89%	10.65%	-22.54%	5.75%
1971	14.30%	11.01%	3.29%	5.97%
1968	11.06%	2.57%	8.49%	5.98%
1972	18.99%	7.26%	11.73%	5.99%
1997	33.36%	12.95%	20.41%	6.02%
1995	37.58%	27.20%	10.38%	6.03%
1970	3.86%	18.37%	-14.51%	6.48%
1993	10.08%	13.19%	-3.11%	6.54%
1996	22.96%	1.40%	21.56%	6.73%
1999	21.04%	-7.45%	28.49%	6.82%
1969	-8.50%	-8.09%	-0.41%	6.87%
1976	23.93%	18.65%	5.28%	7.21%
1973	-14.69%	1.14%	-15.83%	7.26%
1992	7.62%	9.39%	-1.77%	7.26%
1991	30.47%	19.89%	10.58%	7.30%
1974	-26.47%	-3.06%	-23.41%	7.60%
1986	18.67%	19.85%	-1.18%	7.89%
1994	1.32%	-5.76%	7.08%	7.99%
1977	-7.16%	1.71%	-8.87%	8.03%
1975	37.23%	14.64%	22.59%	8.05%
1989	31.69%	16.23%	15.46%	8.16%
1990	-3.10%	6.78%	-9.88%	8.44%
1978	6.57%	-0.07%	6.64%	8.98%
1988	16.61%	10.70%	5.91%	9.18%
1987	5.25%	-0.27%	5.52%	9.20%
1985	31.73%	30.09%	1.64%	9.56%
1979	18.61%	-4.18%	22.79%	10.12%
1982	21.55%	42.56%	-21.01%	10.95%
1984	6.27%	16.86%	-10.59%	11.70%
1983	22.56%	6.26%	16.30%	11.97%
1980	32.50%	-2.76%	35.26%	11.99%
1981	-4.92%	-1.24%	-3.68%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2008-2012
and the Twelve Months Ended February 2013

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2008	1.82%	2.00%	2.24%	2.80%	3.17%	3.67%	4.36%	4.28%
2009	0.47%	0.96%	1.43%	2.19%	2.81%	3.26%	4.11%	4.08%
2010	0.32%	0.70%	1.11%	1.93%	2.62%	3.21%	4.03%	4.25%
2011	0.18%	0.45%	0.75%	1.52%	2.16%	2.79%	3.62%	3.91%
2012	0.18%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
Five-Year Average	0.59%	0.88%	1.18%	1.84%	2.40%	2.95%	3.73%	3.89%

Months	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
Mar-12	0.19%	0.34%	0.51%	1.02%	1.56%	2.17%	2.94%	3.28%
Apr-12	0.18%	0.29%	0.43%	0.89%	1.43%	2.05%	2.82%	3.18%
May-12	0.19%	0.29%	0.39%	0.76%	1.21%	1.80%	2.53%	2.93%
Jun-12	0.19%	0.29%	0.39%	0.71%	1.08%	1.62%	2.31%	2.70%
Jul-12	0.19%	0.25%	0.33%	0.62%	0.98%	1.53%	2.22%	2.59%
Aug-12	0.18%	0.27%	0.37%	0.71%	1.14%	1.68%	2.40%	2.77%
Sep-12	0.18%	0.26%	0.34%	0.67%	1.12%	1.72%	2.49%	2.88%
Oct-12	0.18%	0.28%	0.37%	0.71%	1.15%	1.75%	2.51%	2.90%
Nov-12	0.18%	0.27%	0.36%	0.67%	1.08%	1.65%	2.39%	2.80%
Dec-12	0.16%	0.26%	0.35%	0.70%	1.13%	1.72%	2.47%	2.88%
Jan-13	0.15%	0.27%	0.39%	0.81%	1.30%	1.91%	2.68%	3.08%
Feb-13	0.16%	0.27%	0.40%	0.85%	1.35%	1.98%	2.78%	3.17%
Twelve-Month Average	0.18%	0.28%	0.39%	0.76%	1.21%	1.80%	2.55%	2.93%
Six-Month Average	0.17%	0.27%	0.37%	0.74%	1.19%	1.79%	2.55%	2.95%
Three-Month Average	0.16%	0.27%	0.38%	0.79%	1.26%	1.87%	2.64%	3.04%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields
The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated February 1, 2013

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2013	First	0.2%	0.3%	0.8%	1.8%	3.0%	3.7%	4.7%
2013	Second	0.2%	0.3%	0.9%	1.9%	3.1%	3.8%	4.8%
2013	Third	0.2%	0.4%	1.0%	2.0%	3.2%	3.8%	4.9%
2013	Fourth	0.3%	0.4%	1.1%	2.2%	3.3%	3.9%	4.9%
2014	First	0.3%	0.5%	1.2%	2.3%	3.4%	4.1%	5.1%
2014	Second	0.4%	0.6%	1.3%	2.4%	3.5%	4.2%	5.2%

Measures of the Market Premium

Value Line Return					
As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
February 22, 2013	2.2%	+	10.67%	=	12.87%

DCF Result for the S&P 500 Composite

D/P	(1+.5g)	+	g	=	k
2.36%	(1.0438)	+	8.76%	=	11.22%

where:	Price (P)	at	28-Feb-13	=	1514.68
	Dividend (D)	for	4th Qtr. '12	=	8.94
	Dividend (D)		annualized	=	35.76
	Growth (g)	by	First Call	=	8.76%

Summary			
Value Line			12.87%
S&P 500			11.22%
Average			12.05%
Risk-free Rate of Return (Rf)			3.50%
Forecast Market Premium			8.55%
Historical Market Premium	(Rm)	(Rf)	
1926-2012 Arith. mean	11.72%	3.03%	8.69%
Average - Forecast/Historical			8.62%

Table 7-6: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ Long-Term Returns in Excess of CAPM

Decile	Beta*	Arithmetic Mean Return (%)	Actual Return in Excess of Riskless Rate** (%)	CAPM Return in Excess of Riskless Rate' (%)	Size Premium (Return in Excess of CAPM) (%)
Mid-Cap, 3-5	1.12	13.73	8.61	7.50	1.12
Low-Cap, 6-8	1.23	15.19	10.07	8.23	1.85
Micro-Cap, 9-10	1.36	18.03	12.91	9.10	3.81

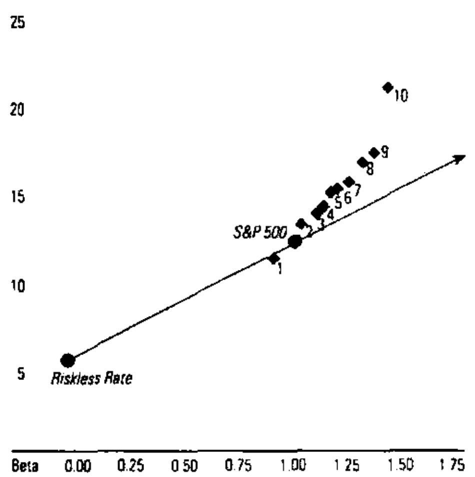
Data from 1926–2012.

*Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926-December 2012.

**Historical riskless rate measured by the 87-year arithmetic mean income return component of 20-year government bonds (5.12 percent).

'Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.82 percent) minus the arithmetic mean income return component of 20-year government bonds (5.12 percent) from 1926–2012.

Graph 7-2: Security Market Line Versus Size-Decile Portfolios of the NYSE/AMEX/NASDAQ



Data from 1926–2012.

Serial Correlation in Small Company Stock Returns

The serial correlation, or first-order autocorrelation, of returns on large capitalization stocks is near zero. [See Table 7-1.] If stock returns are serially correlated, then one can gain some information about future performance based on past returns. For the smallest stocks, the serial correlation is near or above 0.1. This observation bears further examination.

Table 7-7: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ Serial Correlations of Annual Returns in Excess of Decile 1 Returns

Decile	Serial Correlations of Annual Returns in Excess of Decile 1 Return
2	0.22
3	0.27
4	0.25
5	0.25
6	0.33
7	0.27
8	0.34
9	0.29
10	0.38

Data from 1926–2012. Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2013 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

To remove the randomizing effect of the market as a whole, the returns for decile 1 are geometrically subtracted from the returns for deciles 2 through 10. The result illustrates that these series differences exhibit greater serial correlation than the decile series themselves. Table 7-7 above presents the serial correlations of the excess returns for deciles 2 through 10. These serial correlations suggest some predictability of smaller company excess returns. However, caution is necessary. The serial correlation of small company excess returns for non-calendar years (February through January, etc.) do not always confirm the results shown here for calendar (January through December) years. The results for the non-calendar years (not shown in this book) suggest that predicting small company excess returns may not be easy.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2 & 3; Safety Rank of 1, 2 & 3; Financial Strength of B, B+, B++ & A;
Price Stability of 100; Betas of .55 to .75; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Altria Group	TOBACCO	2	2	B+	100	0.55	3
AmerisourceBergen	MEDICNON	3	2	B++	100	0.70	2
Berkley (W.R.)	INSPRPTY	2	2	B++	95	0.70	2
Campbell Soup	FOODPROC	2	2	B++	100	0.55	2
Capitol Fed. Fin'l	THRIFT	3	3	B+	95	0.65	3
Church & Dwight	HOUSEPRD	2	1	A	100	0.60	3
Clorox Co.	HOUSEPRD	2	2	B++	100	0.60	3
DaVita Inc.	MEDSERV	2	3	B+	95	0.70	3
Dollar General	RETAIL	2	3	B++	95	0.60	3
Erie Indemnity Co.	INSPRPTY	3	2	B++	100	0.75	2
Haemonetics Corp.	MEDICNON	3	2	B++	95	0.65	3
Hershey Co.	FOODPROC	2	2	B++	100	0.65	2
Hormel Foods	FOODPROC	3	1	A	100	0.65	3
Kellogg	FOODPROC	3	1	A	100	0.55	3
Kroger Co.	GROCERY	3	2	B++	95	0.60	3
Laboratory Corp.	MEDSERV	3	1	A	100	0.65	3
Marsh & McLennan	FINSERV	3	3	B	95	0.75	3
People's United Fin'l	THRIFT	3	3	B+	95	0.70	3
Philip Morris Int'l	TOBACCO	3	2	B++	95	0.75	3
Quest Diagnostics	MEDSERV	3	2	B++	95	0.75	3
Silgan Holdings	PACKAGE	3	3	B+	95	0.75	3
Stericycle Inc.	ENVIRONM	2	2	B++	95	0.70	3
Verisk Analytics	INFOSER	2	2	B+	100	0.60	3
Waste Connections	ENVIRONM	3	3	B+	95	0.70	2
Weis Markets	GROCERY	3	1	A	95	0.65	3
Average		3	2	B++	97	0.66	3
Gas Group	Average	3	2	B++	100	0.66	3

Source of Information: Value Line Investment Survey for Windows, January 2013

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2007-2011 and
Projected 3-5 Year Returns

Company	2007	2008	2009	2010	2011	Average	Projected 2015-17
Altria Group	49.4%	122.0%	89.5%	NMF	NMF	87.0%	NMF
AmerisourceBergen	15.9%	17.3%	18.8%	21.6%	24.6%	19.6%	27.5%
Berkley (W.R.)	20.6%	16.5%	10.2%	11.4%	7.7%	13.3%	12.5%
Campbell Soup	59.5%	60.5%	105.9%	91.1%	77.8%	79.0%	58.0%
Capitol Fed. Fin'l	3.7%	5.8%	7.0%	7.1%	3.3%	5.4%	4.5%
Church & Dwight	15.6%	15.1%	15.5%	15.3%	15.9%	15.5%	17.0%
Clorox Co.	NMF	-	-	NMF	NMF	-	NMF
DaVita Inc.	19.7%	19.2%	19.8%	22.8%	22.5%	20.8%	19.0%
Dollar General	-	3.8%	10.0%	15.5%	16.4%	11.4%	19.0%
Erie Indemnity Co.	20.6%	18.0%	12.0%	17.8%	21.4%	18.0%	24.5%
Haemonetics Corp.	11.4%	11.9%	12.5%	12.2%	10.7%	11.7%	12.0%
Hershey Co.	81.3%	135.3%	69.3%	65.1%	76.4%	85.5%	52.5%
Hormel Foods	15.8%	14.2%	16.1%	17.0%	17.8%	16.2%	16.0%
Kellogg	43.7%	79.3%	53.3%	57.8%	69.9%	60.8%	33.5%
Kroger Co.	24.0%	24.1%	23.2%	21.1%	30.0%	24.5%	23.5%
Laboratory Corp.	29.4%	30.4%	25.3%	23.7%	25.8%	26.9%	20.0%
Marsh & McLennan	6.9%	NMF	9.2%	8.6%	16.2%	10.2%	20.0%
People's United Fin'l	3.4%	2.7%	2.0%	1.6%	3.8%	2.7%	6.0%
Philip Morris Int'l	39.1%	NMF	NMF	NMF	NMF	39.1%	NMF
Quest Diagnostics	16.7%	17.8%	18.3%	17.9%	19.7%	18.1%	16.0%
Silgan Holdings	24.6%	25.1%	23.2%	26.1%	29.4%	25.7%	20.0%
Stericycle Inc.	18.0%	22.8%	21.1%	20.4%	20.2%	20.5%	15.0%
Verisk Analytics	-	-	-	-	-	-	37.0%
Waste Connections	12.8%	8.2%	8.7%	10.5%	12.1%	10.5%	13.5%
Weis Markets	7.1%	7.1%	9.1%	9.4%	10.1%	8.6%	9.0%
Average						27.4%	21.6%
Average (excluding values >20%)						12.4%	13.3%

Russell A. Feingold

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF RUSSELL A. FEINGOLD ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

Introduction

Q: Please state your name and business address.

A: My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

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

A: I am employed by Black & Veatch Corporation as a Vice President and I lead the Rates & Regulatory Practice of Black & Veatch Management Consulting.

Q: Please describe the firm of Black & Veatch Corporation.

A: Black & Veatch Corporation has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch Management Consulting delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch Management Consulting delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, gas pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q: What is your educational background?

A: I received a Bachelor of Science Degree in Electrical Engineering from Washington University - St. Louis and a Master of Science Degree in Financial Management from Polytechnic Institute of New York University.

Q: What has been the nature of your work in the utility consulting field?

A: I have over thirty-eight (38) years of experience in the utility industry, the last thirty-five (35) years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before utility regulatory bodies and have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Attachment RAF-1.

Q: Have you ever testified before any regulatory commission?

A: Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC"), the National Energy Board of Canada, and numerous state and provincial regulatory commissions, including the Kentucky Public Service Commission (the "Commission") in Case No. 2009-00141. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies. In addition to traditional utility costing and rate design concepts and issues for gas and electric distribution utilities, and gas pipeline companies, my testimony has addressed revenue decoupling mechanisms and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Regulation ("PBR") concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States.

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

A: I am appearing on behalf of Columbia Gas of Kentucky, Inc. ("Columbia").

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

A: The purpose of my testimony is to present and explain Columbia's cost of service studies, its class revenue allocation proposal, and its rate design proposals filed in this case. As part of the rate design section of my testimony, I will present and explain Columbia's proposal to implement a Revenue Normalization Adjustment ("RNA") mechanism to adjust its non-gas base rates on a quarterly basis for unexpected fluctuations in its actual gas volumes and non-gas base revenues. Specifically, I will discuss the reasons why Columbia has decided to propose its RNA mechanism at this time, the industry-wide conditions that support the implementation of such a ratemaking concept, the conceptual underpinnings and computational details of Columbia's RNA mechanism proposal, and the benefits to gas customers and to Columbia created by its RNA mechanism.

Columbia's Cost of Service Studies

Q: Have cost of service studies been submitted in this proceeding?

A: Yes. Filing Requirement # 12-v of Columbia's filing contains its cost of service studies based upon pro forma revenues and costs for the forecasted test period ending December 31, 2014, at present and proposed rates. The studies were performed using Black & Veatch's proprietary, computer-based Gas Cost of Service Model.

Q: Were these cost of service studies prepared by you or under your supervision and direction?

A: Yes, they were.

Q: What was the source of the cost data analyzed in Columbia's cost of service studies?

A: All cost of service data have been extracted from Columbia's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from Columbia's historical books and records.

Q: What classes of service were included in Columbia's cost of service studies?

A: The customer classes reflected in Columbia's cost of service studies are:

- GS RES. – General Service Residential (GSR) and Small Volume Gas Transportation Service (SVGTS) Residential.
- GS OTHER - General Service Other (GSO) for Commercial and Industrial customers and Small Volume Gas Transportation Service (SVGTS) for Commercial and Industrial customers.
- IUS – Intrastate Utility Service and Delivery Service.
- DS-ML/SC – Delivery Service for Mainline customers (MLDS) and Delivery Service for Special Contract (SC) customers.
- DS/IS – Interruptible Sales Service (IS) and Delivery Service.

Q: How are these rate classes configured with regard to sales and transportation service customers?

A: These customer classes are configured as combined classes that include both sales service and transportation service customers. A gas utility's cost of service study should recognize that sales service and transportation service customers both require delivery service to physically move gas on its gas system. For example, it costs a gas utility the same amount to have a service line and meter in place at a customer's premises, irrespective of whether the gas moving through the service line and meter is customer-owned gas transported by the utility, or gas it owns that is sold to the customer. Similarly, the volume of gas used by a customer during a peak period establishes the customer's contribution to the system peak. A gas utility's pipeline system does not need to be larger or smaller if the customer, instead of the utility, owns the gas as it moves through its gas system. Therefore, the allocation of distribution costs for sales service and transportation service for the same customer should be based on allocation factors that include both sales and transportation load characteristics.

Q: Please describe in more detail Columbia's cost of service studies presented in this proceeding.

A: The presentation of Columbia's cost of service studies is structured as follows:

- Schedule 1 – presents a summary of results for Columbia's two separate cost of service studies described below.
- Schedule 2 – presents Columbia's cost of service study at present and proposed rates based on a Design Day demand allocation method with a customer component of distribution mains.
- Schedule 3 – presents Columbia's cost of service study at present and proposed rates based on a Peak and Average demand allocation method without a customer component of distribution mains.

- Schedule 4 - presents a complete description and back-up calculations for all the allocation factors used in the functionalization, classification, and allocation phases of the cost of service studies.

The structure for each filed cost of service study is described below. *Pages 1-12* present the detailed results of the cost of service study by FERC or primary account. In particular, *Page 12* presents the total revenue requirement computed for each customer class at the system average rate of return. *Page 13* presents a unit cost analysis for each customer class. *Pages 14-25* present the details of the Functionalization phase. *Pages 26-61* present the details of the Classification phase. *Pages 62-133* present the details of Columbia's functionalized and classified revenue requirement by customer class. *Pages 134-143* list the functionalization, classification, and class allocation factors utilized for each account in Columbia's total revenue requirement. Finally, *Page 144* presents the results of the cost of service study by customer class at proposed rates.

Each of these two sets of sheets is structured in the same format. The rate base is presented on lines 1 through 128. Expenses including O&M, customer accounting, A&G, depreciation, taxes other than income, gross receipts tax and income tax are presented on lines 130 through 352. Revenue is presented on lines 357 through 366. Net income at present rates is presented on line 370. A summary of revenue, expenses, net income, and rate of return is presented on lines 376 through 416. Finally, the total revenue requirement computed for each customer class at the system average rate of return is presented on lines 418-436.

Q: Please discuss the factors which you believe can influence the overall cost allocation framework utilized by a gas distribution utility.

A: In undertaking a cost of service study, the overall framework within which a gas distribution utility performs its cost of service study can be influenced by various factors. By overall framework, I mean the three standard steps or phases followed by a utility when performing a cost study - cost functionalization, cost classification, and cost allocation. In my opinion, these factors can include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the gas utility. The physical configuration of the utility's gas system refers to considerations such as: (1) transmission and/or distribution system configuration; (2) mainline pipeline functionality; and (3) system operating pressure configuration. These considerations include determining whether: (1) the distribution system is a centralized grid/single city-gate or a dispersed/multiple city-gate configuration; (2) the gas utility has an integrated transmission and distribution system or a distribution-only operation; and (3) the system operates under a multiple-pressure based or a single-pressure based configuration.

With regard to data availability, the structure of the gas utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by rate/customer class, operating unit or geographic region, and the types of load data available.

State regulatory policies and requirements refer to the particular approaches used to establish utility rates in the state. For example, any specific methodological preferences or guidelines for performing cost of service studies or designing rates established by the state regulatory body can affect the particular cost allocation method(s) presented by the gas utility.

Q: How do these factors relate to the specific circumstances applicable to Columbia?

A: Regarding the physical configuration of Columbia's gas system, it is a dispersed/multiple city-gate distribution system and a multi-pressure based system. Columbia has detailed plant accounting records for many of its distribution-related facilities, and details for some of the larger operating expense categories. Finally, over the years, this Commission appears to have accepted Columbia's filing of two cost of service studies in previous proceedings and has encouraged Columbia to continue using multiple cost studies.

Q: What is the purpose of a cost of service study?

A: A cost of service study is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of Columbia's total cost of service (i.e., Columbia's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and to help determine the individual class revenue requirements.

Q: Are there certain guiding principles which should be followed when performing a cost of service study?

A: Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question - which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by Columbia in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Columbia's gas distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There is generally a direct link between the manner in which costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with some measure of the minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant which is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Commodity related costs are those costs which vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by Columbia for its sales service customers.

Q: **What steps did you follow to perform Columbia's cost of service studies?**

A: I followed three broad steps to perform the cost of service studies: (1) functionalization; (2) classification; and (3) allocation. The first step or phase, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. For Columbia, the functional cost categories associated with gas service include: gas supply, production, and distribution. Classification of costs, the second phase, further separates the functionalized plant and expenses into the three cost-defining characteristics of services rendered, as previously discussed: (1) customer; (2) demand or capacity; and (3) commodity or energy. The final phase is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on external factors such as customer, demand, commodity or revenue-related allocation factors, and internal factors that are combinations of the external factors.

Q: How does the cost analyst establish the cost and utility service relationships you previously described?

A: To establish these relationships, the cost analyst must analyze the gas utility's gas system design and operations, its accounting records, and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q: What do you mean by the term "direct assignment?"

A: The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups.

Direct assignment of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q: Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A: No. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expenses cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q: As part of your work, did you review and analyze Columbia's gas system design and operations?

A: Yes. Since it is widely recognized that a utility's plant in service components provide the most direct link to a utility's gas service requirements, I initially focused my efforts on better understanding the nature and operation of Columbia's gas system. This effort included review of Columbia's gas distribution system and the types and levels of costs incurred in connecting various sized customers to its distribution system.

Q: Please explain the most important considerations you relied upon in determining the cost allocation methodologies which were used to perform Columbia's cost of service study.

A: As stated above, it is important to recognize the cost causative characteristics of the cost elements which are allocated within any class cost of service study. Additionally, the cost analyst needs to develop data in a form which is compatible with and supportive of rate design proposals. Of further concern is the availability of data for use in developing alternative cost allocation factors. In evaluating any cost allocation methodology, consideration should be given to:

1. Recognition of cost causality as opposed to value of service;
2. Results which are representative of the true costs of serving different types of customers;
3. A sound rationale or theoretical basis;
4. Stability of results over time;
5. Logical consistency and completeness; and
6. Ease of implementation.

Q: What are the key issues related to the allocation of demand-related costs within a gas utility's cost of service study?

A: A complex part of the allocation process is the allocation of demand-related costs. Any number of methodologies has been used to develop allocation factors for the demand components of costs. In fact, it is not unusual for more than one demand cost allocation methodology to be used in a cost of service study. Despite numerous methods to allocate demand costs, it is fair to say that three basic methodologies form the foundation for the allocation process. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the gas utility. Under this methodology, demand related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group. The Peak Demand Allocation process might focus on a single peak, such as the highest daily demand occurring during the test period. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day. In some instances, it may be appropriate to determine the peak demand responsibility on an hourly basis rather than a daily basis where hourly requirements dictate a company's investment in distribution facilities.

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand. The portion of these facilities is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand).

A more simplistic version of this methodology is the Peak and Average methodology. This cost methodology gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's demand-related costs on a commodity-related basis. The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, may be designed to serve local peaks which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's (rate class), maximum demand, irrespective of the time of the system peak.

Q: How have demand-related costs been allocated in Columbia's cost of service studies?

A: Columbia's cost of service studies use either a coincident peak demand or peak and average allocation factor, both derived on a design day basis, for allocating its capacity related costs to the various customer classes. Capacity costs for Columbia consist of the capacity costs associated with city-gate facilities and the capacity portion of its gas distribution system.

Q: Why doesn't average demand (i.e., annual throughput volumes divided by 365 days) influence the incurrence of demand-related costs?

A: If a gas utility's system was sized and installed to accommodate average gas demands, it would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, it is clear that a peak demand design criteria is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system. As such, cost causation with respect to demand related costs is unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the gas utility's system by customers with low load factors. Clearly, under-utilization of a gas utility's system is a result that is not in the interest of the gas utility to encourage, recognizing that higher system utilization will result in lower unit costs to all customers served by the gas utility.

For the above-stated reasons, it is inappropriate to rely upon only a commodity-based allocation factor, as derived from annual gas throughput volume, for purposes of allocating demand related costs for a gas utility.

Q: Why did you choose to utilize Columbia's design day demand rather than its actual peak day demand as a demand allocation factor?

A: For the allocation of non-gas costs, use of a gas utility's design day demand is superior to using its actual peak day demand, or an historical average of multiple peak day demands over time, for purposes of deriving demand allocation factors for a number of reasons. These include:

1. A gas utility's system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.
2. Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.
3. Design day demand provides more stable cost allocation results over time.

Q: Why does Columbia's design day demand best reflect the factors that actually cause costs to be incurred?

A: Columbia must consistently rely upon design day demand in the acquisition of its upstream gas supply-related resources and in the design of its own distribution facilities required to serve its firm service customers. And perhaps more importantly, design day demand directly measures the gas demand requirements of Columbia's firm service customers which create the need for Columbia to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of Columbia's operations than to utilize its design peak day requirements within its cost of service study.

Q: What is the nature of the firm demand requirements that Columbia must consider in designing its gas distribution system to deliver under all conditions?

A: Columbia designs its gas distribution system, and has sufficient capacity, to serve the delivery or transportation requirements of all its firm sales and transportation service customers. Therefore, the firm demands of all customers will be treated on an equivalent basis for purposes of cost allocation based on peak demands.

Q: Why is use of design day demand closely related to the change in Columbia's fixed plant investment over time?

A: The change in its design day demand serves as the primary input into Columbia's ongoing decisions to install distribution system facilities to meet firm customer demands for gas delivery service. Gas utilities continually monitor operating pressure to determine when additional capacity must be added to meet design day requirements on individual pipe segments.

Regarding plant investment for meeting growth, the construction cost estimates associated with connecting a new customer to Columbia's gas distribution system are always based upon the capacity level necessary to meet each customer's peak hour demands. An excellent proxy for the peak hour demands used in distribution cost estimating is the customer's design day demand.

Q: Please explain why the use of design day demand provides more stable cost allocation results over time.

A: By definition, a gas utility's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it was not a stable demand determinant, the design of a gas utility's system and supply portfolio would tend to vary and make the installation of facilities a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocators available based on either actual peak day demand or the averaging of multiple peak days.

Q: How was investment in distribution mains classified and allocated in Columbia's cost of service studies?

A: It is widely accepted that distribution mains (Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the gas utility's system. Therefore, to ensure that the rate classes that cause the incurrence of this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a gas utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the gas utility's system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the gas utility.

Q: Is the method used to determine a customer component of distribution mains a generally accepted technique for identifying customer-related costs?

A: Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach; and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, which is the method utilized in Columbia's cost of service studies, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main, where zero inch represents zero capacity. The method regresses unit costs associated with the various sized distribution mains installed on the gas utility system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the gas utility's distribution system, regardless of his peak or annual gas consumption.

The most commonly installed minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, (1) Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners (NARUC), and (2) Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q: If a peak demand methodology and a customer component of distribution mains are your preferred methods for the allocation of demand-related costs and the classification and allocation of distribution mains, why have you also presented a peak and average cost of service study in this proceeding?

A: By performing cost of service studies under various cost allocation methodologies, the boundaries of cost responsibility may be identified. The results can then be used as a tool to guide Columbia's revenue allocation and rate design.

Given adequate time and resources, each individual investment and expense could be analyzed to determine how it is used and what created the need for the investments and operating expenses, and classified accordingly. Such a detailed cost classification study would, perhaps, be more accurate, but very costly to perform. However, the results of such a detailed and extensive cost study (assuming that data is available to accomplish it) may not be any more useful for revenue allocation and rate design than the cost of service studies filed in this proceeding, particularly when the cost analyst considers: (1) the need to ameliorate customer impacts; (2) the limitations of cost tracking of rates designed for a broad class of customers; and (3) the time and financial constraints in preparing a rate filing. The use of more than one cost allocation methodology attempts to recognize the level of judgment inherent in performing cost of service studies and provides this Commission with a reasonable and useable range of results.

Additionally, this Commission appears to prefer having multiple cost studies available for its review and consideration, and Columbia has recognized this preference by its filing of multiple cost of service studies in Case Nos. 2009-00141, 2007-00008, 2002-00145, and 94-179.

In view of these considerations, and to minimize the potential controversy associated with selecting particular cost allocation methods, I have decided to use two common demand cost allocation methods (the design day method and the peak and average method) to determine a range of rate of return values for purposes of evaluating class cost responsibility.

Q: Please describe the special studies you conducted for purposes of allocating other distribution plant investment.

A: Regarding Columbia's major plant accounts, a combination of direct assignments and weighting factors were developed to allocate the following plant accounts: Services - Account No. 380, Meters - Account No. 381, House Regulators – Account No.

383, and Industrial Measuring & Regulating Station Equipment - Account No. 385. In particular, the weighting factors reflect any differences in the unit costs that particular customer groups cause Columbia to incur. For example, the average installed cost of a meter to serve a residential service customer was approximately $156 compared to the average installed cost of a meter to serve an DS/IS customer of approximately $1,992. In addition, the cost of a service line which could serve a residential customer costs less, on a per service basis, than the cost of a service line to serve an industrial service customer.

Q: **Please describe the method used to allocate reserve for depreciation and depreciation expenses?**

A: These items were allocated on the same basis as their associated plant accounts.

Q: **How were distribution-related operation and maintenance expenses allocated in Columbia's cost of service studies?**

A: In general, these expenses were allocated on the basis of the cost allocation methods used for Columbia's corresponding plant accounts. A utility's operation and maintenance expenses generally are considered to support the utility's corresponding plant-in-service accounts. That is, the existence of the particular plant facilities necessitates the incurrence of cost (i.e., expenses) by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Maintenance of Services - Account No. 892, is allocated on the same basis as its investment in Services - Account No. 380. With Columbia's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q: How were Columbia's storage-related costs allocated in its cost of service studies?

A: Columbia's cost of gas stored underground was allocated to its sales service and small volume transportation ("CHOICE") customers based on a winter season allocation factor for each class derived using the gas requirements during the months of November through March in excess of the average monthly gas requirements for the months of April through October.

Q: How were administrative and general expenses allocated in Columbia's cost of service studies?

A: Columbia's cost of service studies allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Specifically, administrative and general expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant or rate base; and (3) O&M expenses. In Columbia's cost of service study, each of its administrative and general accounts was related to one or more of these categories. These categories were then used as a basis to establish an appropriate allocation factor for each account. The allocation factors chosen were broad-based to specifically recognize the Columbia-wide nature of administrative and general expenses.

In particular, labor and supplies expenses (Account Nos. 920 and 921) and employee pensions and benefits (Account No. 926) were allocated using a labor-related allocation factor derived based on all labor costs incurred by Columbia. Similarly, the plant and O&M allocation factors discussed above were derived based on Columbia's total plant investment and total O&M expenses, respectively.

Outside services (Account No. 923) include support activities provided to Columbia directly by outside service providers and its corporate affiliates. These activities relate to various general business functions that support Columbia's gas utility operations. Due to the general nature of these costs and their corporate-wide applicability, these costs were allocated to Columbia's rate classes using a labor-based allocation factor reflecting labor-related costs across all of Columbia's cost accounts.

Q: How were taxes other than income taxes allocated in Columbia's cost of service studies?

A: Columbia's cost of service studies allocated these expenses in a manner to reflect the specific cost causative factors associated with its particular tax expense categories. Specifically, these taxes can be cost classified on the basis of the tax assessment method established for each tax category (i.e., property and payroll). As a result, taxes other than income taxes of a utility typically can be grouped into the following categories: (1) plant; (2) labor; and (3) gas supply-related. In the cost of service study, each of Columbia's taxes other than income taxes accounts was related to one of the above stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each tax account.

Q: How were income taxes allocated in Columbia's cost of service studies?

A: Income Taxes were directly calculated for each rate class based on its income before federal and state income taxes, at Columbia's historical effective rate based on net income at present rates. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues, previously allocated expenses and the various adjustments made Columbia for tax computation purposes. The component of income tax expenses based on the tax deferral created by investments in plant was allocated to each customer class based on the class' allocation of Gross Plant.

Q: Please discuss the results of Columbia's cost of service studies.

A: Referring to Schedule 1, the following cost of service study results at present rates for Columbia's forecasted test period are indicated:

1. The GS Res. class exhibits a below average and negative rate of return under the Design Day Method cost study and a below average rate of return under the Peak & Average Method cost study.
2. The GS Other class exhibits an above average rate of return under both cost studies.
3. The IUS class exhibits a below average and negative rate of return under both cost studies.
4. The DS-ML/SC class exhibits a greatly above average rate of return under both cost studies.
5. The DS/IS class exhibits a greatly above average rate of return under the Design Day Method cost study and a slightly above average rate of return under the Peak & Average Method cost study.

Q: How can cost of service study results such as these provide guidelines for rate design?

A: Results of a cost of service study provide cost guidelines for use in evaluating class revenue levels and class rate structures. With regard to rate class revenue levels, the rate of return results show that certain rate classes are being charged rates that recover less than their indicated costs of service. Obviously, because this condition exists, rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. By adjusting rates in accordance with the cost study, rate class revenue levels can be brought closer in line with the indicated costs of service, resulting in movement of rate class rates of return toward the system average rate of return and resulting in rates that are more in line with the cost of providing service.

Concerning cost justification of rates within each rate class, the classified costs, as allocated to each class of service in the cost study, provide cost information that can be of assistance in determining the need for changes in the relative levels of demand (if they exist), customer and commodity rate block charges.

Q: How were the unit cost analyses presented in Schedules 2 and 3 prepared?

A: Black & Veatch's Cost of Service Model compiles the functionalized, classified and allocated expenses and plant-related data for each class of service. The system average rate of return is applied to the allocated rate base to determine the required net income. This is then grossed up to account for the income tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yields the total revenue requirement for each component of cost at the system average rate of return. The computer model makes this calculation for each of the various cost components (i.e., the customer, demand and commodity portions of the supply, storage, and distribution functional categories). The functionally classified costs are unitized by dividing the total costs by the appropriate number of billing units. Customer-related costs are divided by the number of bills, demand-related costs are divided by the contribution to peak demand and commodity-related costs are divided by the number of Mcf delivered to sales service and CHOICE customers.

Q: Can these unit cost analyses results be used for rate design?

A: Yes, if three part rates (i.e., customer, demand and commodity) were set at the unit cost levels, Columbia's total revenue requirement based on its pro-forma test year would be recovered (assuming customer counts, gas deliveries and other billing determinants were as projected). The unit cost analyses also provide valuable cost information for the design of portions of the tariff. One of the most obvious applications is the use of cost information for establishing cost-based monthly customer charges.

It should be noted, however, that the results produced by a cost of service study are not always relevant to all classes of service. In particular, this applies to Columbia's competitively-situated customers, where rates are based on value of service concepts and competitive considerations. For these customers, the value of gas delivery service to the customer relative to available alternatives, as captured in class revenues, has much more influence on the relative profitability (i.e., rate of return) of that class than cost causation does, as measured by a gas utility's cost of service study. This view is shared by NARUC in its Gas Rate Design Manual where it states that, "Setting rates based on value of service bears little relationship to setting them based on cost of service. When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer." Therefore, the guidelines I discussed above are most useful when evaluating the costs to serve customers in the Company's GS Res., GS Other, and IUS rate classes and less useful when evaluating its DS-ML/SC and DS/IS rate classes which include a relatively large portion of Columbia's competitively-situated customers.

Q: Have you prepared a cost analysis which supports the monthly Customer Charges for all of Columbia's rate schedules?

A: Yes. Schedules 2 and 3, page 13 and pages 110-121 present the components of the customer-classified costs for each of Columbia's customer classes contained in its cost of service studies.

<u>Proposed Class Revenues</u>

Q: Please describe the approach generally followed to allocate the Company's proposed revenue increase of $16,595,510 to its various rate classes.

A: As described earlier, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for each of the Company's rate classes. Based on this evaluation, adjustments to the present revenue levels in certain rate classes were made so that the rates proposed by Columbia moved class revenues closer to the costs of serving those classes.

Q: Did you consider various class revenue options in conjunction with your evaluation and determination of Columbia's interclass revenue proposal?

A: Yes. Using Columbia's proposed revenue increase, and the results of its cost of service studies, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Company personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. It should be noted that present base revenues from General Service Residential customers (67%) and General Service Commercial and Industrial customers (26%) represents approximately 93% of Columbia's total base revenues. Out of necessity, then, the majority of Columbia's proposed revenue increase must be recovered from these two rate classes.

The first and benchmark option that I evaluated under Columbia's proposed total revenue level was to adjust the revenue level for each rate class so that the relative rate of return on net rate base for each class was equal to 1.00 as measured by a combination of the results of Columbia's two cost of service studies. Attachment RAF-2 provides the underlying computations for this option. It indicated that revenue increases were warranted for Columbia's GS-Res., GS-Other, and IUS rate classes, and that decreases were warranted for its DS-ML/SC and DS/IS rate classes. As a matter of judgment, I decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. It should be pointed out, however, that those results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to Columbia's rate classes based on an equal percentage basis of its current non-gas base revenues. By definition, this option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the cost of service study results (as measured by changes in the rate of return on net rate base for each rate class); there was only modest movement towards cost for the majority of Columbia's rate classes (i.e., the resulting rates of return only slightly converged to unity or 1.00). In addition, it is important to recognize that because Columbia's flexibly-priced customers are included in the DS-ML/SC and DS/IS rate classes, any increase in class revenues assigned to these rate classes could not be recovered from such customers. While this option also was not the preferred solution to the inter-class revenue issue, together with the fully cost-based option, it defined a range of results that provided me with further guidance to develop Columbia's class revenue proposal.

Q: What was the next step in the process?

A: After further discussions with Columbia, I concluded that the appropriate inter-class revenue proposal would be one that assigned a revenue increase to each of its rate classes except for the DS-ML/SC rate class in which I maintained the present level of revenues (i.e., no revenue increase). This rate class exhibited a rate of return on net rate base materially above 1.00 at present rates as measured in Columbia's two combined cost of service studies. In addition, most of the customers in these rate classes are currently flexibly-priced or have competitive options that make it impossible to recover additional distribution revenues. Columbia's remaining rate classes received increases in revenues that were generally in proportion to their cost-based revenue requirements at proposed revenue levels (as computed in Columbia's cost of service studies), adjusted for a maximum increase in non-gas base revenues to any one rate class of approximately 1.14 times the overall increase in Columbia's non-gas base revenues. This approach resulted in reasonable movement of the class rates of return on net rate base towards unity or 1.00. That result is reflected on Schedule 1, wherein the rates of return on net rate base are shown to converge towards unity or 1.00 compared to the same measure calculated under present rates. In addition, the amounts of the existing rate subsidies among Columbia's classes were reduced for those classes that received increases in revenues. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable.

Q: Has Columbia prepared a comparison of its present and proposed revenues by rate class?

A: Yes. Schedule M 2.1 presents a comparison of present and proposed revenues for each of Columbia's rate classes and is sponsored by Columbia witness Notestone.

Proposed Rate Design

Q: Please summarize the rate design changes Columbia has proposed in this proceeding.

A: Columbia has proposed the following rate design changes to its current rate schedules:

- The establishment and implementation of a RNA mechanism to address certain of the key business challenges faced by Columbia that negatively impact its ability to achieve the level of non-gas base revenues approved by the Commission in its past rate cases.
- Adjustments to Columbia's monthly Customer Charges (for most rate schedules with proposed revenue increases) toward the indicated customer costs of service by recovering a larger portion of the proposed increases in non-gas base revenues by rate class through these fixed charges.

- Adjustments to Columbia's Delivery Charges (for rate schedules with proposed revenue increases) to recover the remaining non-gas revenue requirement proposed for these rate schedules.

Attachment RAF-3 presents the derivation of Columbia's proposed rates for each of its rate classes. I will discuss the specific rate design changes and supporting rationale for each of Columbia's rate classes later in my testimony. The proposed changes to Columbia's Rates, Rules and Regulations for Furnishing Natural Gas, and the associated Rate Schedules, are presented by Columbia witness Cooper.

Q: Can you please generally describe Columbia's current gas rates?

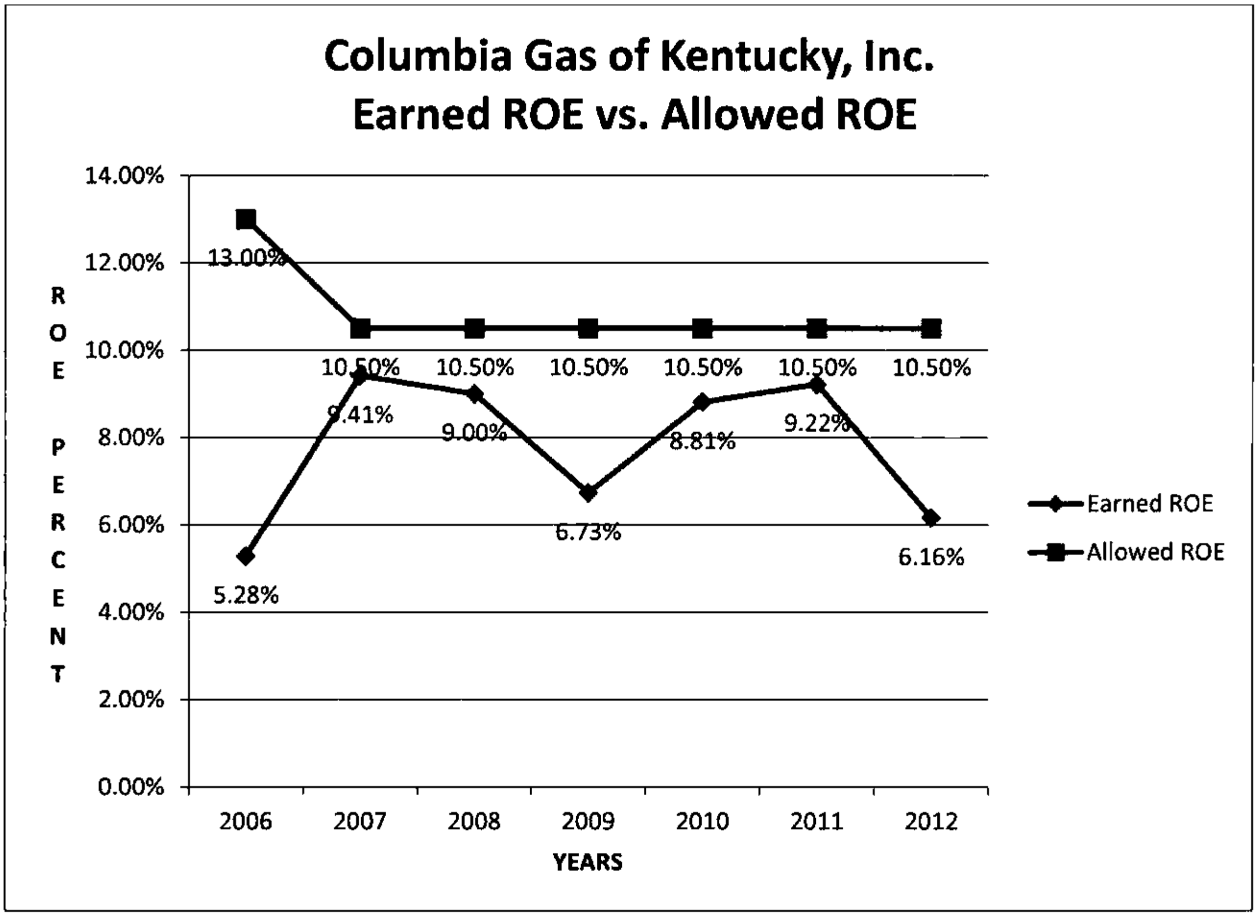
A: Yes. Columbia's current GSR base rate for its residential customers consists of a monthly Customer Charge and a volumetric Delivery Charge for distribution service. The Delivery Charge is assessed to customers on a per Mcf basis. The GSO base rate for commercial and industrial customers consists of a monthly Customer Charge and declining block, volumetric Delivery Charges. Columbia's Delivery Charges are assessed on a per Mcf basis. The monthly Customer Charges and volumetric Delivery Charges recover Columbia's delivery service costs, including the costs that are incurred as a function of the number of customers and the design day demands that are served from its gas distribution system.

Q: Does Columbia warrant changes to its current ratemaking approach to promote economic efficiency?

A: Yes. Columbia's current volumetric rate design is not preferred, in my opinion, because it does an inadequate job of aligning the base revenue recovered by Columbia with the costs incurred to provide gas distribution service. As a result of this misalignment, the current rate design works against the goal of ensuring that Columbia is provided a reasonable opportunity to recover its costs including a return of, and on, the capital that has been invested by Columbia in the property, plant, and equipment that is used and useful in providing gas distribution service. Therefore, it has been extremely difficult in the past for Columbia to earn its allowed rate of return on equity.

Chart 1 below illustrates the inability of Columbia to earn its allowed rate of return on equity even in years when rate increases were approved by the Commission. Once revenues are authorized as part of the ratemaking process and recovery is attempted through a volumetric rate design, the volumetric rate design will almost certainly produce too much or too little revenue to match the utility's fixed costs of providing gas distribution service. In addition, the costs of adding new customers typically exceed by a significant amount the historical level of costs included in base rates to serve customers. As a result, these circumstances faced by Columbia make it very unlikely that it can earn the allowed rate of return on equity in a future period because of revenue erosion and rising costs, which are both beyond Columbia's control.

Chart 1



To understand the difficulty faced by Columbia, it should be noted that over the period of 2003-2011, its total non-gas portion of O&M expenses has increased at a Compound Annual Growth Rate ("CAGR") of 2.3 percent, which is less than the impact of annual inflation, as measured by the Producer Price Index for gas distribution companies, over the same time period. Although there are other factors that can cause this kind of desirable result, the ability of Columbia's management to effectively control costs over that same time period has certainly contributed to the favorable level of these expenses.

Despite this outcome, Columbia has been unable to earn its allowed rate of return. This strongly suggests that there is a need to incorporate different ratemaking and regulatory approaches to provide Columbia with a reasonable opportunity to actually earn its allowed rate of return on equity in future years. Failure to provide Columbia with a rate design under which a reasonable opportunity for cost recovery is realized also causes inefficiencies relative to the removal of disincentives for energy conservation, long-term capital investment, and efficient access to the capital markets.

As explained in more detail below, the combination of changing Columbia's rate design and implementing its proposed RNA mechanism is critical to the long-term provision of efficient, reliable and cost-effective gas distribution service. The various riders approved by the Commission, such as Columbia's Weather Normalization Adjustment (WNA) Clause[1] and its Accelerated Main Replacement Program Rider (AMRP) also are important parts of the ratemaking solution to addressing the issue of providing Columbia with a reasonable opportunity to earn its allowed rate of return. By themselves, however, these other

[1] Columbia's WNA Clause has been in operation since 1996.

rate adjustments do not accomplish the goal of providing Columbia with a reasonable opportunity to earn its allowed rate of return, even in the period immediately following the completion of a rate case. The proposed implementation of its RNA mechanism and further increases in the recovery of fixed costs through its monthly customer charges is a necessary condition for addressing this critical business challenge faced by Columbia.

Q: In recent times, what portion of Columbia's fixed costs has been recovered through its current volumetric delivery charges?

A: Since Columbia's last rate case in 2009, approximately 55 to 60 percent of its current non-gas base revenue has been recovered annually through its volumetric delivery charges. In my general industry experience, this amount is above average compared to the level of fixed costs recovered through volumetric charges by other gas distribution utilities.

Q: What is the nature of gas distribution costs recovered in a utility's base rates?

A: The gas distribution costs of a gas utility are fixed in nature and do not vary with throughput volume. A gas utility designs and installs its gas distribution system in a manner that is capable of meeting its customers' design day requirements at the time each customer is connected to the utility's gas distribution system. Placing these facilities in service permits the gas utility to serve the changes in load that occur over time due to extreme weather (i.e., design day peak load conditions) or economic conditions. Once the facilities are installed to serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers.

Q: What are the business challenges of being able to provide a gas utility with a reasonable opportunity to recover these types of fixed gas delivery service costs through a current rate design that relies heavily upon a volumetric rate component?

A: Essentially, the challenges fall into two broad categories and a third related category. First, there are challenges that relate to economically efficient price signals. Second, there are challenges that relate to the failure to provide a gas utility with a reasonable opportunity to collect its authorized level of revenue. Third, the challenges that fall into the first two categories are made worse in the context of other policy objectives that promote cost-effective energy conservation to address resource constraints, obtain more efficient use of capital, and to help manage price level and volatility risks.

Q: Please describe the failure to provide economically efficient price signals to a gas utility's customers.

A: When fixed costs are recovered volumetrically, customers who conserve "save costs" (through reduced rate revenues) that the utility does not save. This causes more frequent rate cases and from an economic perspective wastes resources. An economically efficient price signal matches the reduction in cost for the utility with the reduction in cost for the consumer. In the case of Columbia, the cost reduction from energy conservation is seen in lower gas commodity-related costs. Any customer savings in excess of the cost of gas overstates the value of conservation and results in both excess investments by the customer and cross subsidies among customers.

Q: Please describe the failure to provide the gas utility with a reasonable opportunity to collect its approved level of revenue.

A: A fundamental tenet of rate regulation provides that rates create a reasonable opportunity for the utility to earn its allowed rate of return. This regulatory principle has its foundations in a Missouri case before the U. S. Supreme Court where Justice Brandeis concluded that a utility is permitted an *opportunity to earn the cost of service* including a return of and on the assets devoted to public service.[2] (Em-

[2] Missouri *ex rel.* Southwestern Bell Tel. Co. v. Public Service Commission, 262 U. S. 276, 290-291 (1923).

phasis added). This regulatory principle is well accepted and has a long history of application.

The allowed return together with operating and maintenance expenses (excluding gas costs), depreciation expenses, and taxes for a test year constitutes the utility's revenue requirements for delivery service. For gas delivery service, none of these costs varies with the volume of gas consumed by customers. This fact is recognized by regulatory bodies because they do not weather normalize any of these costs as would be appropriate if the costs varied with the volume of gas consumed.

The recovery of revenues occurs in a prospective period, the first year referred to as the Rate Effective Period. The dollars that are actually available for the earned return in the Rate Effective Period equal revenue minus all of the costs incurred in that same year, not the level of costs included in the test year and used for ratemaking purposes to establish the revenue requirement. Thus, if rates do not provide a reasonable opportunity of producing the allowed revenue because of changing use patterns, even though costs equal test year costs, the opportunity to earn the allowed return disappears.

Even if the annual revenue obtained in the Rate Effective Period coincidently matches the authorized revenue, a volumetric rate design still poorly aligns the flow of revenue a natural gas distribution company receives with the way that costs are incurred to provide its public utility service. Looking at this from a customer's perspective, the volumetric rate design tends to also swing monthly base rate bills up or down without regard to the fixed nature of the costs that are being incurred to provide base rate service. Thus, a volumetric base rate falsely suggests that a customer that reduces consumption will somehow produce a corresponding effect on the utility's costs of providing gas delivery service.

The fundamental point is that sales volume variation and changing numbers of customers from the level assumed for the test year results in revenue and an actual earned return variation, either higher or lower than the amount specified for ratemaking purposes. Actual earned return over time does not equal the allowed return even though earnings vary from year to year under a variety of circumstances including declining use per customer, conservation, price elasticity responses, asymmetric costs, and other relevant factors. Nevertheless, volumetric recovery of fixed costs fails to provide a reasonable basis for cost recovery as well as a reasonable opportunity to earn the allowed rate of return without an appropriate adjustment to reflect the changing level of billing determinants on a near real time basis.

The solution to this fundamental inability to even have an opportunity to earn the allowed return is to permit the gas utility to "break the link" between revenues and volumes using a ratemaking mechanism, such as the RNA mechanism proposed by Columbia. Its proposed rate mechanism provides that type of periodic adjustment that can satisfy the objective of providing a reasonable opportunity to earn the allowed return when properly structured. I will describe the proposed RNA mechanism below in detail and demonstrate how it works in conjunction with both Columbia's base rates and its WNA Clause to provide a more reasonable opportunity to recover costs with changes in gas usage, while at the same time protecting the customers from paying excess revenue in the event that gas usage patterns would otherwise increase revenues.

Q: What business challenges have most influenced the decisions by gas distribution utilities to propose revenue decoupling mechanisms?

A: The business challenges that have most influenced the decisions by gas distribution utilities to propose revenue decoupling mechanisms have included weather variability and warming temperatures, the ongoing energy efficiency and conservation efforts of their customers, and the resulting decline in average use per customer. Based on my discussions with Columbia staff, I understand that each of these factors, other than most weather variability[3], has impacted Columbia's financial performance and its customers' bills. The general impacts of these phenomena on Columbia are further described by Columbia witness Miller.

Q: How would you describe Columbia's historical gas usage experience for its residential customers?

A: As discussed by Columbia witness Gresham, Columbia has experienced substantial declines in use per customer within its residential class. Weather normalized use per customer for Columbia's residential customers has fallen 31% since 1993 and 17% over the last 10 years. This equates to a reduction in customer usage of approximately 1.9% per year for the past 10 years, and 1.2% in the last 5 years, which is not unlike other gas customers throughout the U.S., caused primarily by increased efficiency of gas appliances (especially space heating equipment), reduced appliance saturation in homes with natural gas, and tighter, more energy efficient homes. Attachment RAF-4 demonstrates that over the last ten (10) years, the average annual use per customer has declined significantly in Columbia's residential service class.

[3] Weather variability during the months of December through April is addressed through Columbia's currently-effective WNA Clause. However, this does not represent the Company's total weather variability because it excludes other months with Heating Degree-Days (HDDs).

Q: Against what reference point should Columbia's decline in use per customer be reviewed?

A: The reference point should be the use per customer level established in each of Columbia's previous base rate cases. Referring to Attachment RAF-4, the annual "baseline" use per customer for the Residential class established in Columbia's last base rate cases to design Columbia's base rates were as follows:

Table 1 – Residential Use Per Customer – Past Rate Cases

Case No.	From	To	Usage per Customer
94-179	January 1, 2003	March 1, 2003	98.2 Mcf
2002-00145	March 1, 2003	September 1, 2007	84.4 Mcf
2007-00008	September 1, 2007	October 27, 2009	69.2 Mcf
2009-00141	October 27, 2009	December 31, 2012	70.8 Mcf

You can readily see that over the succeeding years after a rate case was completed, Columbia never experienced a gas sales level equal to the "baseline" use per customer amount.

Q: What conclusion do you reach from this gas usage data?

A: Columbia's "baseline" use per customer level established in its previous rate cases for its Residential class has not been representative of the actual use per customer it experienced in subsequent years. To the extent the "baseline" use per customer level is not representative of Columbia's expected future trends, its base rates will not properly recover the fixed costs incurred to provide its customers with gas distribution service.

Q: Have you examined how the non-gas base revenues collected by Columbia have varied historically?

A: Yes. Attachment RAF-5 presents the non-gas base revenue impact experienced by Columbia in its Residential rate class due to fluctuations in gas volumes caused by declining use per customer. Over the last ten (10) years, Columbia incurred non-gas base revenue losses in each of those years with the exception of 2008 and 2009. The total non-gas base revenue losses from Columbia's volumetric delivery charges during that period amounted to almost $10.6 million, or approximately $1.1 million per year. As a point of reference, Columbia's total approved non-gas base revenue from its Delivery Charge for the Residential rate class in its last rate case was approximately $16.5 million.

Q: Is Columbia's above-described experience unusual in the gas distribution industry?

A: No. This type of under-recovery of fixed costs is not unique to Columbia. Under-recovery has been quite commonplace in the gas distribution segment of the energy industry, which has prompted the types of ratemaking changes I will discuss later in my testimony.

Q: Is this the first time that Columbia has attempted to address these types of business challenges through changes in its ratemaking approach?

A: No. In its past rate cases, Columbia proposed to increase its monthly Customer Charges so that they would more closely reflect the fixed customer-related costs it incurs to provide gas delivery service. However, the continued reliance on the ratemaking principle of gradualism by the Commission and other stakeholders has moderated the degree of increase in these fixed charges from the levels that were sought by Columbia.

In its 2009 rate case, Columbia proposed a Straight Fixed-Variable ("SFV") rate design for its Residential rate classes to address the above-described business challenges. Columbia also proposed a two-year phase-in for its SFV rate design proposal so the then current monthly Customer Charges within the Residential rate classes would gradually be increased to the full cost-based level. It is my belief that this ratemaking method was not acceptable to the parties in that proceeding.

With these continuing efforts as a backdrop, Columbia made the decision in this filing to propose its RNA mechanism as a viable alternative to the rate-making approaches it has considered and proposed in the past, and as an important step towards addressing the business challenges faced by Columbia.

Q: Can you please compare and contrast Columbia's RNA mechanism proposal with other ratemaking alternatives such as SFV rate design and rate stabilization mechanisms?

A: Yes. While SFV rate design is a form of revenue decoupling, its structure is very different from Columbia's proposed RNA mechanism. In simple terms, a SFV rate design adjusts the gas utility's underlying rate structure by increasing its monthly customer charges to a full cost-based level and eliminating its volumetric delivery charges. Under this ratemaking approach, the gas utility's total cost of delivery service is recovered through the revenues collected under its monthly customer charges. In contrast, a revenue decoupling mechanism does not change the gas utility's underlying rate structure, but instead, provides for periodic rate adjustments to enable the gas utility to recover the level of base revenues that was approved in its last rate case by the regulator.

Under a rate stabilization mechanism, which also is different structurally from revenue decoupling, the gas utility has the ability to adjust its rates each year to reflect changes to a wide range of cost of service elements, including revenues, expenses, rate of return, and level of gas volumes. In other words, a rate stabilization mechanism affects both the revenue and cost side of a gas utility's revenue requirement equation. In contrast, a revenue decoupling mechanism is only able to address the revenue side of the equation, so that a gas utility's opportunity to earn its allowed rate of return continues to be directly affected by its ability to effectively manage the total costs of operating its gas distribution system on a going forward basis.

Q: How will the RNA mechanism proposed by Columbia address the decline in customer usage?

A: Columbia's proposed RNA mechanism represents the required fundamental change to the utility ratemaking process to recognize that a utility such as Columbia has difficulty in establishing a reasonable level of volumes in a rate case that can accurately represent its actual volumes in future periods. As a consequence of this existing process, the volumetric delivery charges that Columbia would derive in its rate case, and that the Commission would approve, are unlikely to reflect the level of base rates required in future periods to fully recover its approved level of fixed operating costs.

Q: In what other manner will the proposed RNA mechanism impact Columbia?

A: The proposed RNA mechanism will align the interests of Columbia with the interests of its customers, policymakers, conservation advocates, and others with respect to energy conservation and efficiency programs for Columbia's customers. Columbia's proposed RNA mechanism will address the financial challenges caused by its traditional rate design, its customers will have greater opportunities to lower their gas bills through the energy efficiency and conservation programs offered by Columbia, and policy considerations related to climate change and related environmental issues will be recognized as customers use less energy. It will place Columbia in a stronger position to consider various energy conservation and efficiency programs in the future to help offset the volatility and unpredictability of natural gas prices because it will no longer be placed in a financially disadvantageous position caused by declines in use per customer.

The appropriateness of this type of ratemaking solution was recognized by the Oregon Public Utility Commission ("OPUC") in its approval in 2002 of a revenue decoupling mechanism for Northwest Natural Gas Company ("NW Natural"). There, the OPUC affirmed the severance of the connection between profits and sales and acknowledged the conflict between the motivation to sell energy and the motivation to promote reduction in energy consumption. From that time, many other utility regulators have followed the lead of Oregon in approving similar ratemaking mechanisms for other gas utilities.

Q: Why is it important to "break the link" between Columbia's revenues and sales to achieve enhanced energy efficiency and conservation goals?

A: Breaking this link is important because it eliminates Columbia's "Throughput Incentive" that is inherent in the way its gas rates have been historically designed. The "Throughput Incentive" financially motivates a utility such as Columbia to increase deliveries of natural gas and to maximize the "throughput" of natural gas across its utility system. Under the traditional utility ratemaking structure, a utility is financially motivated to increase its deliveries in a future period because its rates are designed to recover most fixed costs on a volumetric basis – causing the utility's revenues to increase as its sales increase. Under this ratemaking approach, an increase in the recovery of fixed costs will occur when sales are higher. Conversely, a decrease in the recovery of fixed costs will occur when sales are lower. This situation creates a natural disincentive for utilities to promote conservation or energy efficiency initiatives because such actions will reduce the utility's revenues and resulting earnings.

Columbia's proposed RNA mechanism will adjust its rates on a periodic basis to offset the revenue impact of increases or decreases in sales. By doing so, its proposed revenue decoupling mechanism will effectively eliminate the link between sales and revenues. Hence, it would encourage Columbia to be more supportive of measures that promote decreased energy usage, conservation, or other energy efficiency initiatives.

Q: How does revenue decoupling work?

A: While such a ratemaking mechanism can take several forms, the basic approach consists of defining a target for the utility's non-gas base revenues and placing over- and under-collections of revenue with reference to that target in a deferred account for refund or recovery in a subsequent period. Under these mechanisms, the gas utility cannot increase its earnings by increasing its sales volumes because any over-collected non-gas revenues are deferred for future refunding to customers. Similarly, any non-gas revenue losses resulting from reductions in sales volumes would not decrease the utility's earnings since the revenue lost would be accrued in the current period for subsequent collection from customers. Obviously, though, changes in Columbia's costs would continue to impact its achieved level of earnings.

Q: Is it necessary to continue to use some measure of sales volumes to compute a gas utility's unit rates?

A: Yes. Under a revenue decoupling mechanism, however, the sales level assumed in the utility's last rate case upon which its base rates were designed is not blindly adhered to for purposes of representing the level of sales the utility actually achieves in a future 12-month period. By utilizing customers' actual sales levels and relating that amount to the utility's approved level of distribution non-gas revenues, rates can be adjusted to recover the appropriate level of revenues to produce the margin authorized by the regulator. In other words, the utility's realized distribution non-gas revenues are no longer inextricably linked to its rate case sales level.

Q: How is revenue decoupling an improvement over traditional ratemaking?

A: The de-emphasis of sales volumes in the operation of a revenue decoupling mechanism better recognizes the way consumers actually perceive, value, and purchase services offered by gas and electric utilities. A consumer does not look at utility services and consciously make a decision to purchase a certain number of cubic feet of gas or kilowatt-hours of electricity. Instead, the consumer purchases utility services to acquire light, heat, air conditioning and a wide range of other consumer needs and conveniences. Therefore, we should not continue to hold the financial health of utilities hostage to the fluctuating sales levels resulting from such consumer choices. If over time consumers are able to utilize energy commodities more efficiently, through adoption of energy conservation and energy efficiency techniques promoted by utilities and others, the utilities should not be penalized for these beneficial societal actions.

Q: Would implementation of a revenue decoupling mechanism lessen the computational precision by which a gas utility's base rates are set?

A: No. Under a revenue decoupling mechanism, the utility's base rates will continue to be computed by rate class and they will continue to be designed to recover Columbia's approved level of non-gas revenue requirement. Even more precisely, however, they will reflect the customers' actual gas consumption.

Q: Does the implementation of a revenue decoupling mechanism provide the utility with a guarantee that it will achieve the financial performance previously approved by the regulator?

A: No. In order to achieve its financial expectations, the utility must still actively manage its costs and growth in customers relative to the levels approved in its last rate case to achieve its financial expectations. The re-establishment of the utility's sales levels that I just described only takes gas volumes out of the rate-making equation. It does not eliminate any of the utility's responsibilities to prudently manage the business factors that are under its control. And since the cost side of the ratemaking equation is not affected by the operation of the utility's revenue decoupling mechanism, it does not lessen the utility's incentive to become a more efficient operation through the ongoing pursuit of cost reduction opportunities.

Q: What nationwide trends have you seen related to revenue decoupling mechanisms for gas distribution utilities?

A: Overall, there has been a strong recognition and endorsement throughout the utility industry of ratemaking approaches that "decouple" a utility's sales from its revenues. In my opinion, such a ratemaking approach is now widespread as its conceptual underpinnings have gained acceptance by a growing number of utility regulators as the challenges in the utility industry have become more evident and pronounced.

As of 2002, there were only three (3) states that had approved revenue decoupling mechanisms for gas utilities – and as of May 2013 there were twenty-one (21) states that have approved revenue decoupling, and five (5) additional states that have approved SFV rate design. Attachment RAF-6 presents a map of the U.S. which depicts the extent to which revenue decoupling has been approved, or is currently being addressed, in the various states. This data reflects states where revenue decoupling mechanisms or SFV rate structures has been approved since both "decouple" a utility's sales from its revenues.

Q: How many gas customers are served today under approved revenue decoupling mechanism tariffs?

A: Approximately 30 million residential gas customers are currently served under approved revenue decoupling mechanism tariffs as reported at the American Gas Association ("AGA") Rate Committee Meeting and Regulatory Issues Seminar, October 30, 2012. There are currently about 65 million residential gas customers served by gas utilities in the U.S.

Q: What is the overall structure of revenue decoupling mechanisms approved by utility regulators in the U.S.?

A: The vast majority of revenue decoupling mechanisms approved in the U.S. are designed on a "full" decoupled basis. This means that the ratemaking mechanism addresses all factors (including variations in weather) that impact use per customer. It should be noted that in the states where a single ratemaking mechanism is not used to achieve "full" revenue decoupling, the vast majority of utility regulators also have approved companion WNA mechanisms for those utilities to specifically address the impact of weather upon their gas volumes and non-gas revenues. This would also be the case for Columbia with the Commission's approval of its proposed RNA mechanism.

Q: What are the factors that have driven the recent level of interest in revenue decoupling?

A: I believe there are two key factors that have driven the recent interest in revenue decoupling. First, it is widely acknowledged by utilities, regulators, legislators, and other stakeholders that utilities have an inherent disincentive to promote energy efficiency. This is caused by the prevalence of volumetric-based rate structures for gas utilities that create a decline in non-gas revenues with a decline in customers' gas usage. Revenue decoupling removes this inherent disincentive as a necessary prerequisite to utilities offering energy efficiency and conservation programs to their customers.

Second, as a result of the ongoing decline in use per customer, most gas utilities have experienced an under-recovery of non-gas revenues as I discussed previously. This serious financial impact can be mitigated with revenue decoupling.

Q: Have other participants in the gas industry endorsed the concept of revenue decoupling to address the inherent disincentive that a utility has to promote energy efficiency?

A: Yes. With the increased volatility in energy prices and the resultant unprecedented upward pressure being placed on customers' utility bills, many energy industry groups are now publicly advocating a renewed focus on promoting cost-effective energy efficiency measures to help relieve these consumer burdens. These groups include the AGA, the Edison Electric Institute ("EEI"), the Natural Resources Defense Council ("NRDC"), the Alliance to Save Energy, and the American Council for an Energy Efficient Economy ("ACEEE"). These groups realize that a fundamental change must be made to the utility ratemaking process in order to achieve these consumer benefits. They have endorsed the concept of revenue decoupling as their solution to the problem as demonstrated in the Joint Statement of the American Gas Association and the Natural Resources Defense Council submitted to the National Association of Regulatory Utility Commissioners (NARUC), in July 2004.

In the Joint Recommendation submitted in November 2003 to the NARUC by the NRDC and the Edison Electric Institute, the NRDC and EEI issued a particularly pointed statement when they said that to eliminate a powerful disincentive for energy efficiency and distributed-resource investment, they both support the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes.

Q: Has any other industry organization recognized revenue decoupling as a viable ratemaking concept to address this issue?

A: Yes. NARUC has recognized that revenue decoupling as a ratemaking concept provides earnings stability for utilities and removes the disincentives for promoting energy conservation. In particular, in its Resolution on Gas and Electric Efficiency, Sponsored by NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, Committee on Energy Resources and the Environment, adopted by the NARUC Board of Directors on July 14, 2004, NARUC made reference to the above-mentioned groups and stated that among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure the utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail sales.

In its 2005 Fall Meeting, NARUC's Board of Directors adopted the "Resolution on Energy Efficiency and Innovative Rate Design," dated November 16, 2005. As set forth in this second resolution, NARUC encouraged state utility regulators and other policy makers to review the rate design approaches they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices.

The NARUC resolution also recognized that the traditional volume driven state approach to regulating the rates that utilities charge to deliver natural gas might tend to misalign the interests of natural gas utilities and the goals of energy efficiency and energy conservation. As part of this review, NARUC further encouraged state utility regulators and other policy makers to consider in their review innovative rate designs including "energy efficiency tariffs" and "decoupling tariffs." In addition, the resolution recognized several utilities that have received approval of revenue decoupling mechanisms, fixed-variable rates and other innovative rate design approaches.

In response to the May 2008 Second Joint Statement of the American Gas Association and the Natural Resources, NARUC issued a Resolution on the Second Joint Statement of the American Gas Association and the Natural Resources Defense Council in Support of Measures to Promote Increased Energy Efficiency and reduction in Greenhouse Gas Emissions, Sponsored by the Committee on Gas and Energy Resources and the Environment. This resolution was adopted by the NARUC Board of Directors on July 23, 2008. This resolution again encouraged state commissions and other policymakers to review and give strong consideration to approving gas distribution proposals consistent with the principles and recommendations made in the AGA/NRDC Statement.

Q: Have any national policy initiatives been undertaken to address the deficiencies in traditional utility ratemaking?

A: Yes. In July 2005 the U.S. Department of Energy and U.S. Environmental Protection Agency, with the participation of over 50 utilities, public utility commissions, energy consumers, and non-governmental groups set a broad course for encouraging greater energy efficiency investment in the United States.

The National Action Plan for Energy Efficiency ("Action Plan") emphasizes the need to eliminate ratemaking and regulatory disincentives or barriers through its recommendation that utility regulators modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. Specifically, the Action Plan states that removing the throughput incentive is one way to remove a disincentive to invest in efficiency. It is widely recognized that a revenue decoupling mechanism is a ratemaking approach that can address the "Throughput Incentive" utilities have when their rates are designed so that fixed costs are recovered through volumetrically-based energy charges.

I also would note that in NARUC's Resolution Supporting the National Action Plan for Energy Efficiency, Sponsored by the Executive Committee and the Committees on Consumer Affairs, Electricity, Energy Resources and the Environment, and Gas, adopted by the NARUC Board of Directors on August 2, 2006, it endorsed the principal objectives and recommendations of the Action Plan, and commends to its member commissions a state-specific, or where appropriate, regional review of the elements and potential applicability of energy efficiency policy recommendations outlined in the Action Plan, in an effort to identify potential improvements in energy efficiency policy nationwide. The NARUC Resolution cites five key elements of the Action Plan, including the modification of ratemaking practices to align utility incentives with the delivery of cost effective energy efficiency and to promote energy efficiency investments.

Q: Does the Energy Independence and Security Act of 2007 address revenue decoupling in conjunction with the Act's directives on utility energy efficiency programs?

A: Yes. Section 532(b) (6) (A) of the Act states that the rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency. Further, from a policy perspective, the Act directs each state regulatory authority to consider separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer. Clearly, revenue decoupling mechanisms and SFV rate design are two different ratemaking approaches that do achieve this policy objective.

Q: Does the American Recovery and Reinvestment Act of 2009 address the concept of revenue decoupling within the context of the energy efficiency initiatives delineated in the Act?

A: Yes. Section 410 (a) (1) of the Act specifically states that the applicable State regulatory authority will seek to implement a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently. As I discussed earlier, this alignment can be achieved by a utility and its stakeholders through the implementation of a revenue decoupling mechanism.

Q: Has the financial community recognized the value of ratemaking solutions to address the conditions faced by gas utilities?

A: Yes. The financial community has discussed the impact of energy conservation and usage on gas utilities. It has acknowledged that rate design solutions such as revenue decoupling favorably address the financial consequences of reduced usage on gas utility systems. For example, in its report, "Impact of Conservation on

Gas Margins and Financial Stability in the Gas LDC Sector," Special Comment Report, Moody's Investor Service, dated June 2005, Moody's Investor Service issued a *Special Comment* report that specifically addressed this topic. The Moody's report stated that having utility rate designs that compensate the gas distribution utilities for margin losses caused by variations in gas consumption due to conservation as with variations due to weather, would serve to stabilize the utility's credit metrics and credit ratings.

Q: What are the key design elements of a revenue decoupling mechanism for a gas distribution utility?

A: A revenue decoupling mechanism for a gas distribution utility should be designed to periodically adjust its base rates to reflect changes in distribution non-gas revenue due to variances in gas volumes. The key design elements for such a ratemaking mechanism are as follows:

- It should be structured so that the mechanism adjusts the utility's rates for changes in its customers' gas use, and the resulting change in non-gas revenues, caused by all relevant factors.[4]
- It should be applicable to the utility's rate classes that are most affected by the factors that cause changes in gas use per customer.

[4] Unless variability in weather has already been either fully or partially addressed through the gas utility's implementation of a WNA mechanism.

- It should adjust rates in a manner to reflect the change in actual non-gas revenues generated from customers and the non-gas revenues approved by the utility regulator for each rate class in the gas utility's most recently completed rate case.
- The frequency of rate adjustments under the utility's revenue decoupling mechanism should be set so that adjustments can be made as soon as feasible after the actions that gave rise to the need for the rate adjustment (e.g., energy efficiency measures initiated by the customer, change in weather from normal levels).

Q: Does Columbia's proposed RNA mechanism represent an effective solution to the aforementioned ratemaking challenges it has experienced?

A: Yes. Columbia's proposed RNA mechanism is fair, symmetrical, and beneficial to Columbia and its customers for the following reasons:

1. Under its proposed RNA mechanism, Columbia will be able to continue to embrace energy conservation and efficiency measures for its customers without the continual real threat of margin losses due to declining gas sales per customer.

2. Columbia's proposed RNA mechanism relies upon realistic gas volume levels for computing its unit rates charged to its Residential customers.
3. Columbia's proposed RNA mechanism is a more effective ratemaking method to address the issue of margin volatility on a quarterly basis, and year-to-year, compared to budget billing and gradual periodic increases in its monthly customer charges.

Q: Please explain the structure and key design elements of Columbia's proposed RNA mechanism.

A: Columbia's proposed RNA mechanism will adjust the base rates of Rate Schedules GSR and SVGTS GSR on a quarterly basis to reconcile the difference in actual non-gas revenue as reported for the aggregate of these rate schedules compared to the approved comparable revenue amount established in its most recently approved rate case. This mechanism will adjust Columbia's base rates for Rate Schedules GSR and SVGTS GSR to account for changes in gas usage per customer after the application of its WNA Clause and will provide Columbia with a better opportunity to achieve the level of non-gas revenues previously approved by the Commission.

Columbia's proposed RNA mechanism is a form of revenue decoupling, and it is characterized as a "partial" revenue decoupling mechanism since variations in gas usage due to weather are separately tracked and base rates are adjusted through Columbia's currently-effective WNA Clause in the months in which the WNA is in effect.[5] Columbia proposes to continue the operation of its WNA Clause and views its RNA mechanism proposal as a natural next-step in its ratemaking evolution, and a companion ratemaking mechanism to its WNA Clause, to achieve "full" revenue decoupling. Columbia's WNA Clause has been in operation since 1996.

In conjunction with its WNA Clause, Columbia's proposed RNA mechanism will break the link between its residential revenues and sales volumes in order to align the interests of Columbia and its residential customers with respect to energy conservation and efficiency efforts that serve to lower customers' gas usage.

Columbia's proposed RNA mechanism will be computed and applied to residential customers' bills on a quarterly basis, with a two-month lag to accommodate the compilation and reporting of data to derive the adjustment amount. In other words, the rate adjustment under the RNA mechanism computed based

[5] Since Columbia's currently-effective WNA Clause adjusts its non-gas base rates only during the months of December through April, its proposed RNA mechanism which is designed to operate year-round will also adjust its non-gas base rates for any weather variations that occur during the months of May through November.

on first quarter results (i.e., three months ended March) will be applied to customer bills rendered in June through August.

The "baseline" use per customer and non-gas base revenue per customer will be established in Columbia's current rate case, and they will be adjusted as necessary in its future rate cases.

Q: Please explain why Columbia's proposed RNA mechanism will apply only to its residential service class and the corresponding transportation service class for its residential choice customers.

A: These two rate classes comprise the majority of Columbia's customer base and represent over sixty (60) percent of its non-gas base revenues. Moreover, the gas usage of these groups is most sensitive to the impacts of energy efficiency and conservation.

Q: Is it unusual for a revenue decoupling mechanism, such as Columbia's proposed RNA mechanism, to have a billing lag?

A: No. A billing lag is inherent in these types of ratemaking mechanisms to accommodate the need for the utility to compile the necessary actual data to compute the appropriate rate adjustments for inclusion in customers' bills. Every one of the revenue decoupling mechanisms that have been approved to date by utility regulators has a billing lag as an integral part of the computational process. Under Columbia's proposed RNA mechanism, there is a two-month lag after the end of each quarter in the adjustment to customers' bills. This period is the shortest amount of time under such a ratemaking mechanism to complete the computational, reporting, and regulatory requirements.

Q: Has the Columbia's RNA mechanism proposal been reflected in its gas tariff?

A: Yes. The tariff sheets for Columbia's RNA proposed mechanism are presented in its proposed tariff sponsored by Columbia witness Cooper.

Q: Please explain how Columbia's proposed RNA mechanism will operate.

A: The quarterly rate adjustment under Columbia's RNA mechanism will be computed as follows:

1. Determine the Authorized Quarterly Non-Gas Revenue ("AQNR") based on the final revenue approved by the Commission for Rate Schedules GSR and SVGTS GSR in Columbia's most recently completed rate case. The quarterly non-gas revenue amounts will be fixed based on the compliance rates filed by Columbia at the completion of its rate case, and will be computed as the sum of the monthly billing determinants times the final rates for Rate Schedules GSR and SVGTS GSR in each quarter.

2. Determine the Weather Adjusted Quarterly Booked Revenue ("WAQBR") for the Residential class (Rate Schedules GSR and SVGTS GSR) based on the applicable billing months' non-gas base rate revenue recorded on Columbia's books, which includes the sum of the revenues calculated for each residential customer under Columbia's currently-effective WNA Clause.
3. The quarterly Revenue Normalization Adjustment ("RNA") under Columbia's RNA mechanism will be equal to the AQNR amount minus the WAQBR amount for the applicable billing quarter for Rate Schedules GSR and SVGTS GSR.
4. The RNA Billing Factor ("RNABF") for Rate Schedules GSR and SVGTS GSR will be equal to the RNA amount, plus or minus any prior quarter's under or over collection under the RNA mechanism, divided by the estimated normalized gas volumes for Rate Schedules GSR and SVGTS GSR for the next quarter following the current quarter's RNA.[6]
5. The RNABF determined above for Rate Schedules GSR and SVGTS GSR will be applied to that class' gas bills beginning with the first billing cycle for the third succeeding billing month following the billing quarter's RNA.[7]

---

[6] For example, the RNA for Rate Schedules GSR and SVGTS GSR for the first billing quarter (January through March) will be divided by that class' estimated volumes for the next RNA billing period (June through August) to determine the applicable RNABF.

[7] For example, the RNA for Rate Schedules GSR and SVGTS GSR for the first billing quarter would be billed beginning with the first billing cycle for the June billing month.

6. A reconciliation of the RNA billing will be computed on a quarterly basis by comparing actual collections under the RNA mechanism with the RNA amount. The calculated under or over collection will be included in the RNABF in the second succeeding RNA billing period.

Q: **Have you developed an example of the supporting computations for Columbia's proposed RNA mechanism that it proposes to file each quarter with the Commission?**

A: Yes. Attachment RAF-7 presents an example of the supporting computations for Columbia's proposed RNA mechanism. The computations mirror the details provided in Columbia's proposed tariff on how its RNA mechanism will operate.

Q: **Have you evaluated the expected performance of Columbia's proposed RNA mechanism based on its recent experience with changes in use per customer and non-gas base revenues?**

A: Yes. Attachment RAF-8 illustrates the results of a simulation of the operation of the RNA mechanism and the determination of the associated rate adjustment factors for the residential service classes under proposed rates during a three-year period. Customer billing adjustments under the RNA mechanism were computed for the average residential customer as if the RNA mechanism was in effect during this three-year period. The simulation used as a base the following data for customers served under Columbia's Rate Schedules GSR and SVGTS GSR: (1) authorized monthly non-gas base revenues from Columbia's last rate case; (2) monthly non-gas revenues that were booked during 2010-2012; and (3) monthly normalized gas volumes during 2010-2012.[8]

Q: Would you please describe the results of your analysis for Columbia's Residential Service rate classes?

A: Yes. The results of the analysis shown in Attachment RAF-8 present the quarterly RNABF and annual average bill impacts under the proposed RNA mechanism for Columbia's Residential Service customers. As a point of reference, the average annual gas bill of the average-sized residential sales customer under Columbia's current rates is approximately $551.00, including all applicable non-base rate charges. Specifically, the maximum positive adjustment (bill increase) under Columbia's proposed RNA mechanism during any year was $4.65 in 2012. The maximum negative adjustment (bill decrease) during any year was ($2.87) in 2011.

---

[8] For 2012, the RNABFs that were derived based on the RNA amounts for the 3rd and 4th quarters utilized Columbia's estimated normalized monthly volumes from its 2013 Financial Plan.

Q: Will Columbia have to propose any changes to its current ratemaking methods to accommodate its proposed RNA mechanism?

A: With the implementation of its proposed RNA mechanism, to avoid an issue of double-counting, Columbia proposes to suspend the annual rate adjustment associated with its Energy Efficiency/Conservation Program Lost Sales ("EECPLS").

Q: What are the benefits to Columbia and to its residential customers of implementing its proposed RNA mechanism?

A: There are several significant benefits from implementing the Columbia's proposed RNA mechanism, including:

- Columbia's RNA mechanism will break the link between the gas consumption of its residential customers and its revenues and result in a better alignment of the interests of Columbia and its customers. Under the RNA mechanism, Columbia will be able to continue to embrace energy conservation and efficiency measures without the continual real threat of margin losses due to declining gas sales per customer.
- With the implementation of Columbia's RNA mechanism, customers will pay each year approximately the same amount for gas delivery service as if Columbia had experienced normal weather and no incremental energy conser-

vation by its customers, which is the same basis upon which the Commission establishes Columbia's base rates. Obviously, though, the customer who does conserves natural gas will continue to experience a significant benefit through the bill reductions created by the reduction in gas commodity charges. Ultimately, Columbia's RNA mechanism together with its WNA Clause will result in a heating customer's bill more accurately reflecting the margin recovery amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts and warmer-than-normal weather in the amount they pay for gas supply service, which currently amounts to approximately half of its total bill.

- It will benefit Columbia and its customers seeking price stability by reducing price volatility due to variations from gas commodity costs and the prevailing economic conditions.
- It may lessen the frequency and magnitude of Columbia's future base rate cases because of the enhanced opportunity to recover its Commission-approved revenue requirement, which can lead to reduced rate case expenses that benefit all customers.

Q: Mr. Feingold, please summarize your position regarding Columbia's proposed RNA mechanism.

A: In my professional opinion, the Company's proposed RNA mechanism is absolutely necessary and appropriate for the purpose of eliminating disincentives to the promotion of energy efficiency and to solve the chronic business challenges faced by Columbia that I discussed earlier. This ratemaking proposal is just, reasonable and conceptually sound, provides significant benefits to Columbia and its residential customers, will better accommodate energy efficiency, addresses a fundamental deficiency in utility ratemaking, and is a ratemaking approach endorsed by energy trade associations, several state public utility commissions and NARUC to further promote and expand the energy efficiency programs offered by gas utilities that are so critical to their customers' ability to moderate the impact of rising energy prices.

Q: What general guidelines did you use in the development of Columbia's proposed rate design by class of service as presented in Attachment RAF-3?

A: I maintained the monthly customer and delivery charge structure that currently exists for Columbia's sales and transportation service customers. Also, within each rate class, the base rate delivery charges for sales customers and transportation customers were designed to be the same. Finally, I was cognizant of the fact that customers within certain of Columbia's rate schedules are already paying monthly fixed charges that are higher than those reflected in Columbia's current base rates because of the additional monthly fixed charge that is added under

Columbia's AMRP. As an example, Columbia's residential customers are currently charged an AMRP amount of $1.06 per month in addition to the current monthly Customer Charge of $12.35, for a total of $13.41 per month. When Columbia's rates filed in this case are approved by the Commission, the AMRP amount will be reset to zero because the underlying fixed costs reflected in this charge will be recovered through Columbia's new base rates.

Q: Please explain how you developed the proposed rates applicable to Columbia's customers served under its GSR and SVGTS Residential rate schedules.

A: My first step was to derive the monthly Customer Charge. I did this based on the results of Columbia's customer cost analysis contained in both of its cost of service studies and the consideration of other non-cost factors which I will describe below. Schedules 2 and 3, page 13 indicate that the monthly customer costs for the GS-Res. rate class range between $22.28 and $31.93 based on the results of the two cost of service studies presented by Columbia. The level of this proposed charge also was influenced by certain non-cost considerations, including: (1) the magnitude of Columbia's revenue increase request and the proposed revenue increase assigned to its residential rate class; (2) the magnitude of the increase in this charge necessary to maintain the current Delivery Charge for this rate class at its current level; and (3) the level of monthly customer charges approved by the Commission in the recent past.

The midpoint of the range of the Company's customer-related costs is $27.11 per month. Increasing Columbia's current monthly Customer Charge of $12.35 per month for these rate schedules halfway toward this cost-based midpoint equates to a customer charge of $19.73 per month. Further, adjusting Columbia's current residential Customer Charges to recover the entirety of the proposed increase in non-gas base revenues under the residential rate schedules results in a customer charge of $21.62 per month. Increasing the current Customer Charges by 1.25 times the percentage by which the non-gas base revenues of the residential class are proposed to be increased results in a customer charge of $17.65 per month. Finally, the Commission has approved monthly customer charges for residential gas customers as high as $20.70 per month.[9]

Based on these considerations, I set the monthly Customer Charges for Columbia's residential rate schedules at $18.50 per month. In my judgment, this proposal is reflective of the underlying fixed customer-related costs incurred by Columbia while recognizing the various other considerations discussed above which serve to moderate the higher level for this charge that is justified based on the cost-to-serve these customers.

---

[9] Delta Natural Gas Company, Case No. 2010-00116, Order dated October 21, 2010.

Next, I derived the Delivery Charge so that it would recover the remaining non-gas base revenue requirement proposed for these rate schedules.

Q: Please explain how you developed the proposed rates applicable to Columbia's customers served under its GSO and SVGTS Commercial and Industrial rate schedules.

A: Similar to the process described above, I first derived the monthly Customer Charges for these rate schedules and then I derived the Delivery Charges to recover the remaining non-gas base revenue requirement for these rate schedules. Schedules 2 and 3, page 13 indicate that the monthly customer costs for the GS-Other rate class range between $36.56 and $46.09 (with a cost-based midpoint of $41.33) based on the results of the two cost of service studies presented by the Company. These amounts are much higher than Columbia's current monthly Customer Charge for these rate schedules of $25.13 per month. As with the residential rate schedules, the level of this proposed charge also was influenced by certain non-cost considerations similar to the ones I described above. Based on these considerations, I set the monthly customer charges for Columbia's general service rate schedules at $37.50 per month.

Next, I derived the Delivery Charges so that they would recover the remaining non-gas base revenue requirement proposed for these rate schedules.

Q: Please explain how you developed the proposed rates applicable to Columbia's customers served under its IUS and DS/IUS rate schedules.

A: Once again, I first derived the monthly Customer Charge for this rate schedule and then I derived the Delivery Charges to recover the remaining non-gas base revenue requirement for this rate schedule. Schedules 2 and 3, page 13 indicate that the monthly customer costs for the IUS rate class range between $621.63 and $632.59 (with a cost-based midpoint of $627.11) based on the results of the two cost of service studies presented by Columbia. These amounts are higher than Columbia's current monthly Customer Charge for these rate schedules of $331.50 per month. Based on these considerations, I set the monthly Customer Charges for Columbia's IUS and DS/IUS rate schedules at $477.00 per month, which equates to moving the current charge approximately halfway toward the cost-based midpoint for these rate schedules.

Next, I derived the Delivery Charge so that it would recover the remaining non-gas base revenue requirement proposed for these rate schedules.

Q: Please explain how you developed the proposed rates applicable to Columbia's customers served under its MLDS rate schedule.

A: There were no changes made to the rates of the MLDS rate schedule because Columbia has proposed no change to its non-gas base revenues.

Q: Please explain how you developed the proposed rates applicable to Columbia's customers served under its IS and DS/IS rate schedules.

A: Once again, I first derived the monthly Customer Charges for these rate schedules and then I derived the Delivery Charges to recover the remaining non-gas base revenue requirement for this rate schedule. Schedules 2 and 3, page 13 indicate that the monthly customer costs for the IS and DS/IS rate classes range between $600.23 and $604.99 (with a cost-based midpoint of $602.61) based on the results of the two cost of service studies presented by Columbia. These amounts are roughly the same compared to Columbia's current monthly Customer Charge for these rate schedules of $583.39 per month. Based on these considerations, I did not change the current level of the monthly Customer Charges for Columbia's IS and DS/IS rate schedules.

Next, I derived the Delivery Charges so that they would recover the total non-gas base revenue requirement proposed for these rate schedules.

Q: Were typical bill comparisons prepared to illustrate the impact of Columbia's proposed rates on customers' gas bills?

A: Yes. Typical bill comparisons for varying levels of monthly gas usage at current and proposed rates for each of Columbia's rate classes are shown in Schedule N and sponsored by Columbia witness Notestone.

Q: Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Russell A. Feingold, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Russell A. Feingold

STATE OF PENNSYLVANIA

COUNTY OF ALLEGHENY

SUBSCRIBED AND SWORN to before me by Russell A. Feingold on this the 23 day of May, 2013.

Notary Public

My Commission expires: 9/25/16

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Orlando Sciarretti III, Notary Public
Pine Twp., Allegheny County
My Commission Expires Sept. 25, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE
RUSSELL A. FEINGOLD

EDUCATIONAL BACKGROUND

- Bachelor of Science degree in Electrical Engineering from Washington University in St. Louis
- Master of Science degree in Financial Management from Polytechnic Institute of New York University

WORK EXPERIENCE

2007 – Present	**Black & Veatch Corporation** Vice President, Management Consulting Division and Rates & Regulatory Practice Lead
1996 – 2007	**Navigant Consulting, Inc.** Managing Director, Energy Practice - Litigation, Regulatory & Markets Group
1990 – 1996	**R.J. Rudden Associates, Inc.** Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division

1973 – 1978 **Port Authority of New York and New Jersey**
Staff Engineer and Utility Rate Specialist
Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- National Energy Board of Canada
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Kentucky Public Service Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Nebraska Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities

- New Mexico Public Regulation Commission
- New York Public Service Commission
- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- South Dakota Public Service Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of Wyoming

EDUCATIONAL AND TRAINING ACTIVITIES

- Past Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison and University of Chicago School of Business, 1985 – 2013.

- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992, and 2012-2013.
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987 edition.
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress).

PUBLICATIONS AND PRESENTATIONS

- "State Regulatory and Legislative Issues," American Gas Association Financial Forum, May 5-7, 2013
- "Providing Natural Gas to Unserved and Underserved Areas," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 28-31, 2012
- "State Regulatory Issues Affecting Gas Utilities," American Gas Association Accounting Principles Committee Meeting, August 13-15, 2012
- "State Regulatory Landscape and Future Trends Affecting Utilities," American Gas Association Financial Forum, May 6-8, 2012.
- "The Continuing Saga of Fixed Cost Recovery: Arguments in Utility Rate Proceedings," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 30 - November 2, 2011.
- "State Regulatory Issues Affecting Utilities," American Gas Association Accounting Principles Committee Meeting, August 15-17, 2011.
- "State Regulatory Issues Affecting Utilities," Edison Electric Institute/American Gas Association Accounting Leadership Conference, June 26-29, 2011.
- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 15-17, 2011.

- "2011 Forecast – Regulatory Issues and Risks for Utilities," American Gas Association Finance Committee Meeting, March 16-18, 2011.
- "State Regulatory Issues Affecting Utilities," Edison Electric Institute and American Gas Association Accounting Leadership Conference, June 27-30, 2010.
- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 17-19, 2010.
- "A Utility's Regulatory Compact: Where's the Right Balance? – RMEL Electric Energy Magazine, Issue 1 – Spring 2010.
- "Communicating Ratemaking and Regulatory Concepts to a Utility's Stakeholders," American Gas Association, Communications and Marketing Committee Meeting, March 16-17, 2010.
- "Managing Regulatory Risk Workshop", Rocky Mountain Electric League, October 8, 2009.
- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association, 2009 Financial Forum, May 3, 2009.
- "Financial Incentives for Energy Efficiency: Lessons Learned to Date," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 7, 2009.
- "Breaking the Link Between Sales and Profits: Current Status and Trends," Energy Bar Association, Electricity Regulation and Compliance Committee, February 17, 2009.
- "State Ratemaking Issues for Gas Distribution Utilities," Energy Law Journal, Volume 29, No. 2, 2008 (Report of the Natural Gas Regulation Committee).
- "Current Issues in Cost Allocation and Rate Design for Utilities," SNL Energy, Utility Rate Cases Today: The Issues and Innovations, November 6, 2008.
- "Current Issues in Revenue Decoupling for Gas Utilities," American Gas Association, Financial and Investor Relations Webcast, October 16, 2008.
- "Addressing Utility Business Challenges Through the State Regulatory Process," American Gas Association, 2008 Legal Forum, July 20-22, 2008.
- "Earning on Natural Gas Energy Efficiency Programs," American Gas Association Rate and Regulatory Issues Conference Webcast, May 23, 2008.

- "State Regulatory Directions: Utility Challenges and Solutions," American Gas Association Financial Forum, May 4, 2008.
- "Ratemaking and Financial Incentives to Facilitate Energy Efficiency and Conservation," The Institute for Regulatory Policy Studies, Illinois State University, May 1, 2008.
- "Update on Revenue Decoupling and Innovative Rates," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, March 10, 2008.
- "Update on Revenue Decoupling and Utility Based Energy Conservation Efforts," American Gas Association, Rate and Regulatory Issues Conference Webcast, May 30, 2007.
- "A Renewed Focus on Energy Efficiency by Utility Regulators," American Gas Association, Rate and Regulatory Issues Seminar and Committee Meetings, March 26, 2007.
- "The Continuing Ratemaking Challenge of Declining Use Per Customer," American Public Gas Association, Gas Utility Management Conference, October 31, 2006.
- "Understanding and Managing the New Reality of Utility Costs in the Natural Gas Industry," Financial Research Institute, Public Utility Symposium, University of Missouri – Columbia, September 27, 2006.
- "Ratemaking and Energy Efficiency Initiatives: Key Issues and Perspectives," American Gas Association, Ratemaking Webcast, September 14, 2006.
- "Ratemaking Solutions in an Era of Declining Gas Usage and Price Volatility," Northeast Gas Association, 2006 Executive Conference, September 10-12, 2006.
- "Rethinking Natural Gas Utility Rate Design," American Gas Foundation and The NARUC Foundation, Executive Forum, Ohio State University, May 2006.
- "Rate Design, Trackers, and Energy Efficiency – Has the Paradigm Shifted?" Energy Bar Assocation, Midwest Energy Conference, March 2006.
- "Key Regulatory Issues Affecting Energy Utilities," American Gas Association, Lunch 'n Learn Session, November 2005.
- "Decoupling, Conservation, and Margin Tracking Mechanisms," American Gas Association, Rate & Regulatory Issues – Audio Conference Series, October 2005.

- "In Search of Harmony, [Utilities and Regulators] Respondents Weigh in with Needed Actions", Public Utilities Fortnightly, November 2005
- "The Use of Trackers as a Regulatory Tool," Midwest Energy Association – Legal, Regulatory, and Government Relations Roundtable, October 9-11, 2005.
- "Rate Design and the Regulatory Environment," American Gas Association Finance Committee Meeting, October 2005.
- "Creative Utility Regulatory Strategies in a High Price Environment," American Gas Association Executive Conference, September 2005.
- "Revenue Decoupling Programs: Aligning Diverse Interests," The Institute for Regulatory Policy Studies, Illinois State University, May 2005.
- "Key Regulatory Issues Affecting Energy Utilities" American Gas Association Financial Forum, May 2005.
- "Energy Efficiency and Revenue Decoupling: A True Alignment of Customer and Shareholder Interests," American Gas Association Rate and Regulatory Issues Seminar and Committee Meetings, April 2005.
- "Rate Case Techniques: Strategies and Pitfalls" American Gas Association, Rate & Regulatory Issues – Audio Conference Series, March 2005.
- "Regulatory Uncertainty: The Ratemaking Challenge Continues" Public Utilities Fortnightly, Volume 142, No. 11, November 2004.
- "Current Trends in Utility Rate Cases and Pricing: Surveying the Landscape," Platts Rate Case & Pricing Symposium, October 25-26, 2004.
- "State Regulatory Oversight of the Gas Procurement Function" Energy Bar Association, Natural Gas Regulation Committee, Energy Law Journal, Volume 25, No. 1, 2004.
- "Cost Allocation Across Corporate Divisions", American Gas Association, Rate and Strategic Issues Committee Meeting, April 2003.
- "Unbundling Initiatives – How Far Can We Go?" American Gas Association Restructuring Seminar: Service and Revenue Enhancements for the Energy Distribution Business, December 2002.
- "Utility Regulation and Performance-Based Ratemaking (PBR)," PBR Briefing Session sponsored by BC Gas Utility Ltd., April 2002.

- "LDC Perspectives on Managing Price Volatility" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.
- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.
- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999
- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.
- "Asset and Resource Migration Strategies," presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.
- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- "State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.

- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.

- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.

- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.

- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.

- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.

- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.

- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.

- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.

- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.

- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.

- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.

- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.

- Seminar organizer and moderator at the American Gas Association seminar, "Integrated Resource Planning: A Primer," December 1991.

- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.

- "Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.

- "Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.

- "Design of Distribution Company Gas Rates," presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.

- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, "Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," 1988-1990.

- "Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.

- "So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.

- "Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.

- "Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.

- "Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.

- "Gas Transportation Rates - An Integral Part of a Competitive Marketplace," *American Gas Association, Financial Quarterly Review*, Summer 1987.

- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review*, October 1983.

- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.

- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.

- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Rate Committee of the American Gas Association
- Member, Energy Bar Association
- Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of May 2013)

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Summary of Levelized Revenue Increase
(Average of Design Day and Peak & Average Cost Studies)

Line No.		Total CKY	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
1	Rate of Return	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
2	Net Rate Base	$ 203,298,499	$ 138,523,472	$ 49,702,881	$ 94,890	$ 54,282	$ 14,922,975
3	Operating Expenses	$ 48,648,316	$ 33,002,177	$ 14,742,241	$ 66,074	$ 10,486	$ 827,338
4	Customer Accts, Services & Sales Exp.	$ 5,952,664	$ 5,021,527	$ 692,564	$ 459	$ 28,322	$ 209,792
5	Administrative & General Expenses	$ 15,167,736	$ 11,237,455	$ 3,136,506	$ 13,120	$ 17,904	$ 762,751
6	Depreciation Expense	$ 11,548,354	$ 8,666,051	$ 2,176,365	$ 5,857	$ 154,250	$ 545,832
7	General Taxes	$ 3,525,110	$ 2,534,397	$ 735,215	$ 1,477	$ 1,577	$ 252,444
8	Total Expenses	$ 84,842,181	$ 60,461,607	$ 21,482,891	$ 86,986	$ 212,539	$ 2,598,158
9	Return on Net Rate Base	$ 17,463,341	$ 11,899,166	$ 4,269,477	$ 8,151	$ 4,663	$ 1,281,884
10	Income Tax on Return	$ 6,325,796	$ 4,310,269	$ 1,546,545	$ 2,953	$ 1,689	$ 464,340
11	Increase in Uncollectibles	$ 94,422	$ 83,588	$ 8,812	$ 25	$ 191	$ 1,805
12	Increase in General Taxes	$ 1,017,427	$ 731,485	$ 212,200	$ 426	$ 455	$ 72,861
13	Total Levelized Revenue Requirement	$ 109,743,168	$ 77,486,115	$ 27,519,926	$ 98,541	$ 219,537	$ 4,419,049
14	Revenue Under Current Rates	$ 93,147,657	$ 59,998,782	$ 27,032,161	$ 76,729	$ 590,628	$ 5,449,357
15	Levelized Revenue Increase (Decrease)	$ 16,595,511	$ 17,487,333	$ 487,765	$ 21,812	$ (371,091)	$ (1,030,308)

Levelized Revenue Increase - Design Day Cost Study

Line No.		Total CKY	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
16	Rate of Return	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
17	Net Rate Base	$ 203,298,499	$ 155,193,340	$ 45,874,276	$ 94,534	$ 52,547	$ 2,083,803
18	Operating Expenses	$ 48,648,316	$ 33,639,147	$ 14,595,340	$ 66,072	$ 10,276	$ 337,481
19	Customer Accts, Services & Sales Exp.	$ 5,952,664	$ 5,021,527	$ 692,564	$ 459	$ 28,322	$ 209,792
20	Administrative & General Expenses	$ 15,167,736	$ 11,841,464	$ 2,997,559	$ 13,117	$ 17,745	$ 297,851
21	Depreciation Expense	$ 11,548,354	$ 9,340,209	$ 2,059,741	$ 5,331	$ 5,026	$ 138,047
22	General Taxes	$ 3,525,110	$ 2,804,060	$ 673,041	$ 1,471	$ 1,566	$ 44,972
23	TOTAL EXPENSES	$ 84,842,181	$ 62,646,406	$ 21,018,246	$ 86,450	$ 62,935	$ 1,028,144
24	Return on Net Rate Base	$ 17,463,341	$ 13,331,108	$ 3,940,600	$ 8,120	$ 4,514	$ 178,999
25	Income Tax on Return	$ 6,325,796	$ 4,828,965	$ 1,427,415	$ 2,942	$ 1,635	$ 64,839
26	Increase in Uncollectibles	$ 94,422	$ 83,588	$ 8,812	$ 25	$ 191	$ 1,805
27	Increase in General Taxes	$ 1,017,427	$ 809,316	$ 194,255	$ 425	$ 452	$ 12,980
28	Total Levelized Revenue Requirement	$ 109,743,168	$ 81,699,384	$ 26,589,329	$ 97,962	$ 69,726	$ 1,286,767
29	Revenue Under Current Rates	$ 93,147,657	$ 59,998,782	$ 27,032,161	$ 76,729	$ 590,628	$ 5,449,357
30	Levelized Revenue Increase (Decrease)	$ 16,595,511	$ 21,700,602	$ (442,832)	$ 21,233	$ (520,901)	$ (4,162,590)

See Requirement # 12-v, Schedule 2, Page 12 for details.

Levelized Revenue Increase - Peak & Average Cost Study

Line No.		Total CKY	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
31	Rate of Return	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
32	Net Rate Base	$ 203,298,499	$ 121,853,604	$ 53,531,485	$ 95,245	$ 56,017	$ 27,762,147
33	Operating Expenses	$ 48,648,316	$ 32,365,208	$ 14,889,142	$ 66,075	$ 10,696	$ 1,317,196
34	Customer Accts, Services & Sales Exp.	$ 5,952,664	$ 5,021,527	$ 692,564	$ 459	$ 28,322	$ 209,792
35	Administrative & General Expenses	$ 15,167,736	$ 10,633,447	$ 3,275,452	$ 13,123	$ 18,063	$ 1,227,652
36	Depreciation Expense	$ 11,548,354	$ 7,991,892	$ 2,292,988	$ 6,382	$ 303,474	$ 953,617
37	General Taxes	$ 3,525,110	$ 2,264,734	$ 797,389	$ 1,483	$ 1,588	$ 459,916
38	TOTAL EXPENSES	$ 84,842,181	$ 58,276,808	$ 21,947,536	$ 87,522	$ 362,142	$ 4,168,173
39	Return on Net Rate Base	$ 17,463,341	$ 10,467,225	$ 4,598,355	$ 8,182	$ 4,812	$ 2,384,768
40	Income Tax on Return	$ 6,325,796	$ 3,791,573	$ 1,665,675	$ 2,964	$ 1,743	$ 863,842
41	Increase in Uncollectibles	$ 94,422	$ 83,588	$ 8,812	$ 25	$ 191	$ 1,805
42	Increase in General Taxes	$ 1,017,427	$ 653,654	$ 230,145	$ 428	$ 458	$ 132,742
43	Total Levelized Revenue Requirement	$ 109,743,168	$ 73,272,847	$ 28,450,523	$ 99,120	$ 369,347	$ 7,551,331
44	Revenue Under Current Rates	$ 93,147,657	$ 59,998,782	$ 27,032,161	$ 76,729	$ 590,628	$ 5,449,357
45	Levelized Revenue Increase (Decrease)	$ 16,595,511	$ 13,274,065	$ 1,418,362	$ 22,392	$ (221,281)	$ 2,101,974

See Requirement # 12-v, Schedule 3, Page 12 for details.

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requiremer
For the 12 Months Ended December 31, 2014

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	**GSR/GTR Rate Design**								
2	Total Revenue @ Proposed Rates				71,148,068				
3 Less:	Gas Cost Revenue				24,780,205	24,780,205			
4 Less:	Gas Cost Uncollectible Charge [1]		6,098,392	0.0243	148,191	148,191		0.0603	
5 Less:	EAP Revenue			0.0615	491,717	491,717		0.0615	
6 Less:	Administrative Charge Revenue								
7 Less:	Customer Delivery ChargeRevenue	1,439,306		18.50	26,627,161	17,775,429		12.35	8,851,732
8 Less:	EECP			(0.24)	(345,433)	(345,433)		(0.24)	0
9 Less:	AMRP			0.00	0	1,525,664		1.06	(1,525,664)
10	Net Volumetric Base Revenue				19,446,227				
11	All Gas Consumed		7,995,391.7	2.4322	19,446,392	14,963,376		1.8715	4,483,016
12	Total				71,148,233	59,339,148			11,809,084
13	**GSO/GTO/GDS Rate Design**								
14	Total Revenue @ Proposed Rates				31,226,834				
15 Less:	Gas Cost Revenue				12,128,821	12,128,821			
16 Less:	Gas Cost Uncollectible Charge [1]		2,984,895	0.0243	72,533	72,533		0.0603	0
17 Less:	Administrative Charge Revenue	403		55.90	22,528	22,528		55.90	0
18 Less:	Customer Charge Revenue	164,808		37.50	6,180,300	4,141,625		25.13	2,038,675
Less:	AMRP			0.00	0	655,936		3.98	(655,936)
19	Net Volumetric Base Revenue				12,822,652				
20 Less:	First 50 Mcf		2,198,287.6	2.4322	5,346,675	4,114,095	0.421367055	1.8715	1,232,580
21	Next 350 Mcf		2,101,354.1	2.3851	5,011,860	3,814,588	0.390691427	1.8153	1,197,272
22	Next 600 Mcf		603,680.5	2.2990	1,387,839	1,044,126	0.106939723	1.7296	343,713
23	Over 1,000 Mcf		500,491.1	2.1495	1,075,787	790,876	0.081001795	1.5802	284,911
24	Subtotal		5,403,813.3		12,822,161	9,763,685	1.000000000		3,058,476
25	Total				31,226,343	26,785,128			4,441,215

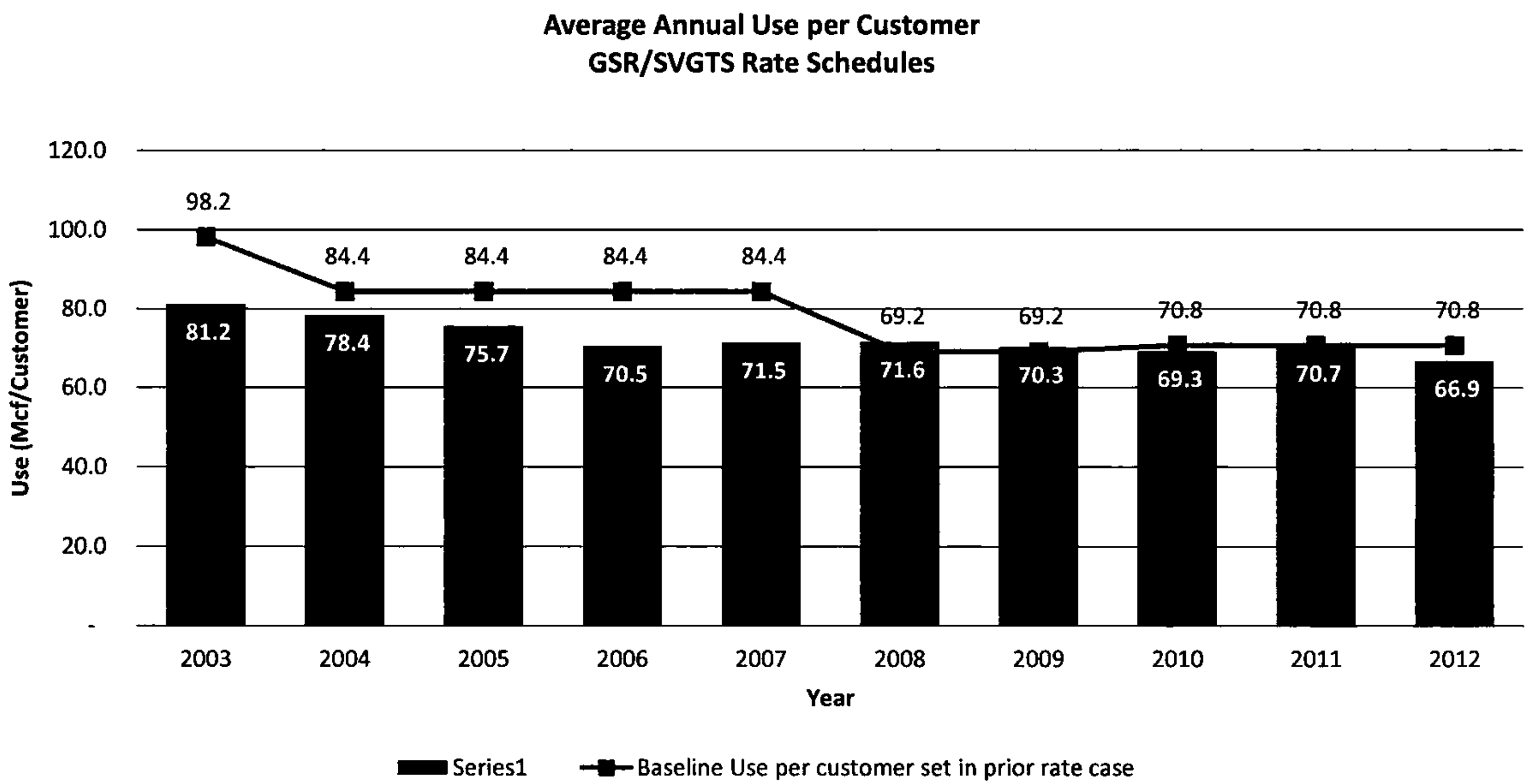
Columbia Gas of Kentucky, Inc
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requiremer
For the 12 Months Ended December 31, 2014

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	**DS/SAS Rate Design**								
2	Total Revenue @ Proposed Rates				4,554,266				
3 Less:	Gas Cost Revenue				0	0			
4 Less:	Gas Cost Uncollectible Charge [1]		0	0.0243	0	0			0
5 Less:	EAP Revenue				0	0			
6 Less:	Customer Charge Revenue	792		583.39	462,045	462,045		583.39	0
7 Less:	Administrative Charge Revenue	792		55.90	44,273	44,273		55.90	0
8 Less:	AMRP			0.00	0	188,171		237.59	(188,171)
9	Net Volumetric Base Revenue				4,047,948				(188,171)
10	First 30,000 Mcf		5,639,178.6	0.6177	3,483,321	3,082,939	0.857804809	0.5467	400,382
11	Over 30,000 Mcf		1,759,200.0	0.3272	575,599	511,048	0.142195191	0.2905	64,551
12	Subtotal		7,398,378.6		4,058,919	3,593,987	1.000000000		464,933
13	Total				4,565,237	4,288,475			276,762
14	**DS3 (Mainline) Customer Charge Rate Design Change**								
15	Total Revenue @ Proposed Rates				75,045				
16 Less:	Gas Cost Revenue				0				
17 Less:	Gas Cost Uncollectible Charge [1]		0	0.0243	0	0			0.0000
18 Less:	EAP Revenue				0				
19 Less:	Customer Charge Revenue	36		200.00	7,200	7,200		200.00	0.0000
20 Less:	Administrative Charge Revenue	36		55.90	2,012	2,012		55.90	0.0000
21	Net Volumetric Base Revenue				65,833				0.0000
22	All Gas Consumed		767,283.0	0.0858	65,833	65,833		0.0858	0.0000
23	Total				75,045	75,045			0
24	**IS Rate Design**								
25	Total Revenue @ Proposed Rates				173,437				
26 Less:	Gas Cost Revenue				134,494	134,494			
27 Less:	Gas Cost Uncollectible Charge [1]		33,099	0.0243	804	804		0.0603	0
28 Less:	Customer Charge Revenue	12		583.39	7,001	7,001		583.39	0
29 Less:	AMRP			0.00	0	2,851		237.59	(2,851)
30	Net Volumetric Base Revenue				31,138				(2,851)
31	First 30,000 Mcf		33,099.0	0.6177	20,445	18,095	1.000000000	0.5467	2,350
32	Over 30,000 Mcf		0.0	0.3272	0	0	0.000000000	0.2905	0
33	Subtotal		33,099.0		20,445	18,095	1.000000000		2,350
34	Total				162,745	163,246			(501)
35	**IUS Rate Design**								
36	Total Revenue @ Proposed Rates				82,718				
37 Less:	Gas Cost Revenue				56,254	56,254			
38 Less:	Gas Cost Uncollectible Charge [1]		13,844	0.0243	336	336		0.0603	0
39 Less:	EAP Revenue				0				
40 Less:	Administrative Charge Revenue				0				
41 Less:	Customer Charge Revenue	24		477.00	11,448	7,956		331.50	3,492
Less:	AMRP			0.00	0	993		41.38	(993)
42	Net Volumetric Base Revenue				14,680				2,499
43	All Gas Consumed		13,844.0	1.0604	14,680	10,729		0.7750	3,951
44	Total		13,844.0		82,718	76,268			6,450

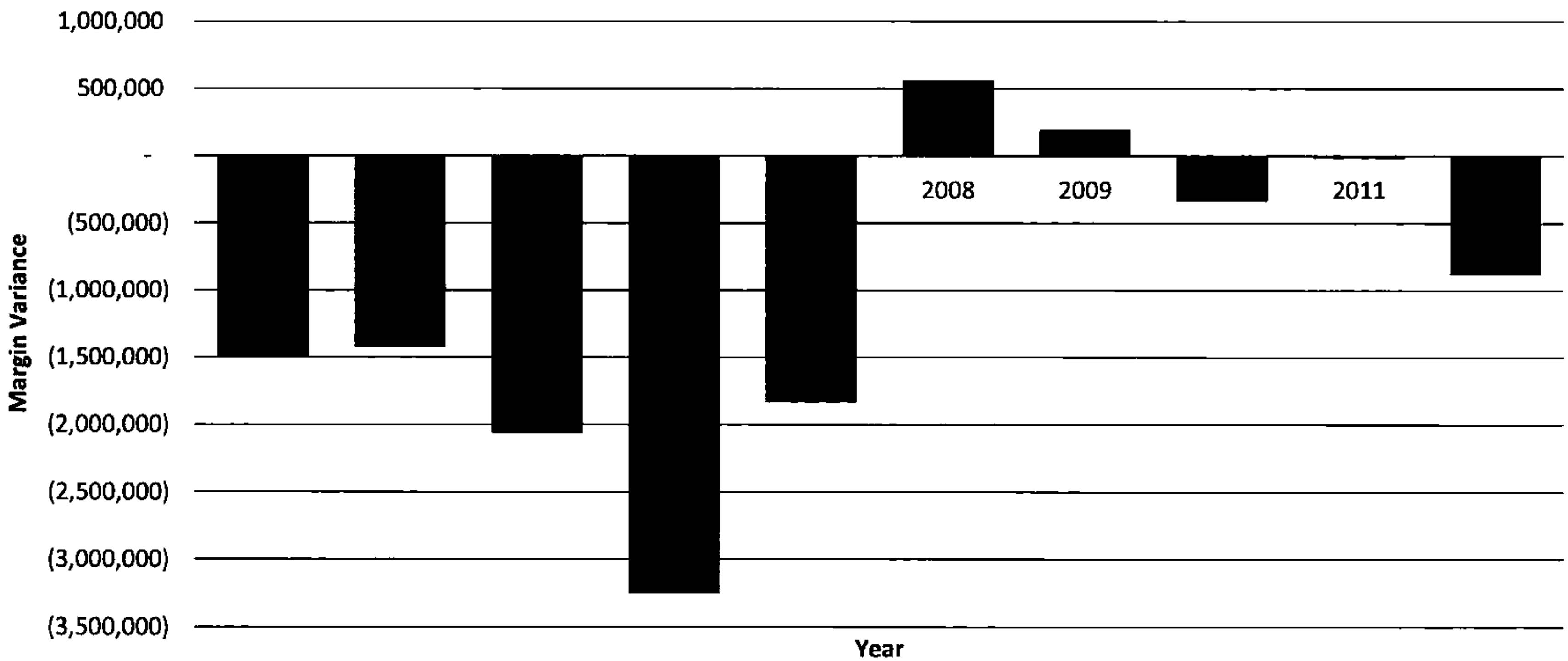
[1]	Gas Cost Uncollectible Charge to GCA Customers	
	Expected Gas Cost Commodity Rate as of February 28, 2013 ($/Mcf	4.2771
	Uncollectible Expense Accrual Rate (See Schedule D-2.1 Sheet 5	0.568963%
	Proposed Rate / Mcf	0.0243

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2014

Line No.		Reference	Detail ($)	Amount ($)
1	**Change in Forfeited Discounts Revenue**			
2	Test Year Forfeited Discounts (Account 487)			356,864.00
3	Test Year Revenue Subject to Late Payment Penalties:			
4 GSR	General Service - Residential	Schedule M-2.1	51,706,021	
5 G1C	LG&E Commercial	Schedule M-2.1	18,403	
6 G1R	LG&E Residential	Schedule M-2.1	15,108	
7 GSO	General Service - Commercial	Schedule M-2.1	20,162,510	
8 GSO	General Service - Industrial	Schedule M-2.1	923,594	
9 IS	Interruptible Service - Industrial	Schedule M-2.1	164,437	
10 IUS	Intrastate Utility Service - Wholesale	Schedule M-2.1	76,767	
11 GTR	GTS Choice - Residential	Schedule M-2.1	7,852,669	
12 GTO	GTS Choice - Commercial	Schedule M-2.1	4,798,113	
13 GTO	GTS Choice - Industrial	Schedule M-2.1	87,513	
14 DS	GTS Delivery Service - Commercial	Schedule M-2.1	1,275,851	
15 DS	GTS Delivery Service - Industrial	Schedule M-2.1	3,012,624	
16 GDS	GTS Grandfathered Delivery Service - Commercial	Schedule M-2.1	543,591	
17 GDS	GTS Grandfathered Delivery Service - Industrial	Schedule M-2.1	377,264	
18 DS3	GTS Main Line Service - Industrial	Schedule M-2.1	75,045	
19 FX1	GTS Flex Rate - Commercial	Schedule M-2.1	55,037	
20 FX2	GTS Flex Rate - Commercial	Schedule M-2.1	53,421	
21 FX5	GTS Flex Rate - Industrial	Schedule M-2.1	308,765	
22 FX7	GTS Flex Rate - Industrial	Schedule M-2.1	203,271	
23 SAS	GTS Special Agency Service	Schedule M-2.1	0	
24 SC3	GTS Special Rate - Industrial	Schedule M-2.1	883,188	
25 Total				92,593,192.98
26	Ratio of Late Payment Penalties to Total Revenue	Line 2 / Line 25		0.003854106
27	Proposed Revenue Subject to Late Payment Penalties:			
28	GSR/GTR Residential	Schedule M-2.1	71,148,068	
29	GSO/GTO/GDS	Schedule M-2.1	31,226,834	
30	DS/SAS	Schedule M-2.1	4,554,266	
31	IS	Schedule M-2.1	173,437	
32	IUS	Schedule M-2.1	82,718	
33	G1C	Schedule M-2.1	18,403	
34	G1R	Schedule M-2.1	15,108	
35	DS3	Schedule M-2.1	75,045	
36	FX1	Schedule M-2.1	55,037	
37	FX2	Schedule M-2.1	53,421	
38	FX5	Schedule M-2.1	308,765	
39	FX7	Schedule M-2.1	203,271	
40	SC3	Schedule M-2.1	883,188	
41 Total				108,797,563
42	Proposed Forfeited Discounts (Account 487)	Line 26 x Line 45		419,317
43	**Proposed Adjustment to Account 487 Revenue**	**Line 46 - Line 2**		**62,453**


Average Annual Use per Customer
GSR/SVGTS Rate Schedules
120.0
100.0
80.0
60.0
40.0
20.0
-
Use (Mcf/Customer)
98.2
84.4
84.4
84.4
84.4
69.2
69.2
70.8
70.8
70.8
81.2
78.4
75.7
70.5
71.5
71.6
70.3
69.3
70.7
66.9
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
Series1
Baseline Use per customer set in prior rate case

Non-Gas Base Revenue Impact from Current Volumetric Delivery Charges
GSR/SVGTS Rate Schedules



Columbia Gas of Kentucky, Inc.
Non-Gas Base Revenue Impact from Current Volumetric Delivery Charges - GSR/SVGTS Rate Schedules
For Years 2003 - 2012

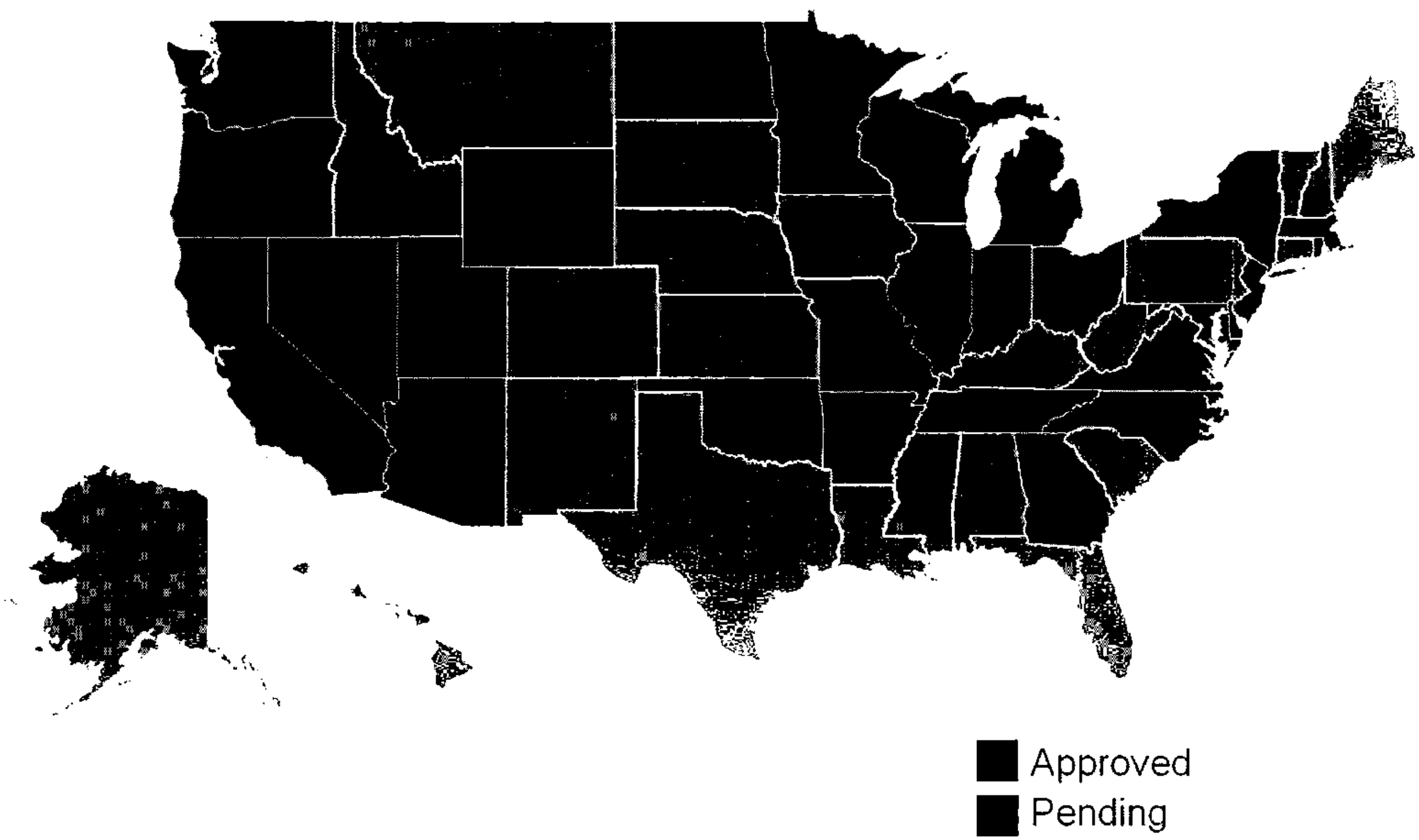
	Jan-Feb 2003	Mar-Dec 2003	2004	2005	2006	Jan-Aug 2007	Sep-Dec 2007	2008	Jan-Oct 2009	Nov-Dec 2009	2010	2011	2012
Year End Customers	127,932	127,932	127,072	126,412	125,429	124,953	124,953	123,724	122,053	122,053	121,780	120,681	120,446
UPC Baseline	98.2	85.4	84.4	84.4	84.4	84.4	69.2	69.2	69.2	70.8	70.8	70.8	70.8
UPC Normalized	81.2	81.2	78.4	75.7	70.5	71.5	71.5	71.6	70.3	70.3	69.3	70.7	66.9
Increase / (Decrease) UPC	(16.95)	(4.15)	(5.98)	(8.72)	(13.86)	(12.92)	2.28	2.44	1.13	(0.47)	(1.49)	(0.08)	(3.91)
Rate / Mcf	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715	1.8715
Increase / (Decrease)	(676,560)	(828,937)	(1,422,535)	(2,063,136)	(3,253,781)	(2,014,876)	177,400	565,005	215,397	(17,833)	(340,071)	(17,984)	(881,163)

Increase / (Decrease) Summary By Year

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Increase / (Decrease)	(1,505,497)	(1,422,535)	(2,063,136)	(3,253,781)	(1,837,476)	565,005	197,563	(340,071)	(17,984)	(881,163)

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167

Natural Gas Revenue Decoupling in the United States (1)



(1) Includes revenue decoupling mechanisms and Straight Fixed-Variable (SFV) rate design
(2) Approved in 26 states, pending in 1 state (as of May 2013)

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment Billing Factor (RNABF) - Computational Example
Residential Service

Line No.	Description		2012 January	February	March	1st Quarter
	(1)		(2)	(3)	(4)	(5)
1	Authorized Quarterly Non-Gas Revenue (AQNR) - Rate Schedules GSR and SVGTS GSR		$4,739,819	$4,657,541	$4,032,197	$13,429,557
2	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule GSR		$ 3,624,389	$ 3,448,168	$ 2,934,402	$ 10,006,959
3	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule SVGTS GSR		$ 1,132,609	$ 1,068,142	$ 909,585	$ 3,110,335
4	Subtotal	(Lines 2 + 3)				$ 13,117,295
5	Revenue Normalization Adjustment (RNA)	(Lines 1 - 4)				$ 312,262
6	Under/(Over) Collection from Prior Period (1)					$ -
7	Subtotal	(Lines 5 + 6)				$ 312,262
			June	July	August	3-Month Total
8	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule GSR (2)		119,592	92,438	83,690	295,720
9	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule SVGTS GSR (2)		37,233	28,256	25,802	91,291
10	Subtotal	(Lines 8 + 9)				387,011
11	RNA Billing Factor (RNABF)	(Line 7/Line 10)				$ 0.8069

(1) For the second preceding RNA Billing Period

Columbia Gas of Kentucky, Inc.
RNA Billing Factor (RNABF) Current Rate Calculation
For the 12 Months Ending December 31, 2012

Residential Service

Line No. (1)	2012 Quarter (2)	Total RNA 1/ (3)	Estimated Normalized Volumes (Mcf) (4)	RNABF Effective Months (5)	Total RNABF ($/Mcf) (6 = 3 / 4)
1	1st Quarter	$312,262	387,011	Jun - Aug 2012	$0.8069
2	2nd Quarter	$578,109	863,662	Sep - Nov 2012	$0.6694
3	3rd Quarter	($67,993)	4,673,320	Dec 2012 - Feb 2013	($0.0145)
4	4th Quarter	($266,563)	2,410,608	Mar - May 2013	($0.1106)
5	Total	$555,816	8,334,601		$0.0667

6	Annual Average Use Per Customer (Mcf)	69.7
7	Annual RNA Bill Impact	$4.65

1/ Page 2 of 6

RNABF - Revenue Normalization Adjustment Billing Factor

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment (RNA)
For the 12 Months Ending December 31, 2012

Residential Service

Line No. (1)	Month (2)	AQNR (3)	WAQBR (4)	Current Quarter RNA (5 = 3 - 4)
1	January	4,739,819	4,756,998	
2	February	4,657,541	4,516,310	
3	March	4,032,197	3,843,987	
4	**1st Quarter**	13,429,557	13,117,295	312,262
5	April	3,087,244	2,639,931	
6	May	2,117,824	2,051,082	
7	June	1,798,639	1,734,584	
8	**2nd Quarter**	7,003,707	6,425,598	578,109
9	July	1,694,888	1,716,318	
10	August	1,674,649	1,692,086	
11	September	1,674,519	1,703,644	
12	**3rd Quarter**	5,044,056	5,112,049	(67,993)
13	October	1,796,249	1,887,322	
14	November	2,467,840	2,720,170	
15	December	3,783,408	3,706,568	
16	**4th Quarter**	8,047,497	8,314,060	(266,563)
17	Total	$33,524,817	$32,969,001	$555,816

AQNR - Authorized Quarterly Non-Gas Revenue
WAQBR - Weather Adjusted Quarterly Booked Revenue

Columbia Gas of Kentucky, Inc.
RNA Billing Factor (RNABF) Current Rate Calculation
For the 12 Months Ending December 31, 2011

Residential Service

Line No. (1)	2011 Quarter (2)	Total RNA 2/ (3)	Estimated Normalized Volumes (Mcf) (4)	RNABF Effective Months (5)	Total RNABF ($/Mcf) (6 = 3 / 4)
1	1st Quarter	($16,671)	426,291.3	Jun - Aug 2011	($0.0390)
2	2nd Quarter	($63,200)	879,780.7	Sep - Nov 2011	($0.0720)
3	3rd Quarter	($91,907)	4,740,235.8	Dec 2011 - Feb 2012	($0.0190)
4	4th Quarter	($172,980)	2,271,760.9	Mar - May 2012	($0.0760)
5	Total	($344,758)	8,318,068.6		($0.0414)

6	Annual Average Use Per Customer (Mcf)	69.3
7	Annual RNA Bill Impact	($2.87)

2/ Page 4 of 6

RNABF - Revenue Normalization Adjustment Billing Factor

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment (RNA)
For the 12 Months Ending December 31, 2011

Residential Service

Line No.	Month	AQNR	WAQBR	Current Quarter RNA
(1)	(2)	(3)	(4)	(5 = 3 - 4)
1	January	4,782,008	4,945,981	
2	February	4,698,267	4,683,894	
3	March	4,058,204	3,925,275	
4	**1st Quarter**	13,538,479	13,555,150	(16,671)
5	April	3,115,041	3,032,245	
6	May	2,133,187	2,204,503	
7	June	1,806,174	1,880,854	
8	**2nd Quarter**	7,054,402	7,117,602	(63,200)
9	July	1,696,379	1,731,362	
10	August	1,677,604	1,691,579	
11	September	1,677,875	1,720,824	
12	**3rd Quarter**	5,051,858	5,143,765	(91,907)
13	October	1,799,437	1,892,646	
14	November	2,472,528	2,588,815	
15	December	3,790,697	3,754,181	
16	**4th Quarter**	8,062,662	8,235,642	(172,980)
17	Total	$33,707,401	$34,052,159	($344,758)

AQNR - Authorized Quarterly Non-Gas Revenue
WAQBR - Weather Adjusted Quarterly Booked Revenue

Columbia Gas of Kentucky, Inc.
RNA Billing Factor (RNABF) Current Rate Calculation
For the 12 Months Ending December 31, 2010

Residential Service

Line No. (1)	2010 Quarter (2)	Total RNA 3/ (3)	Estimated Normalized Volumes (Mcf) (4)	RNABF Effective Months (5)	Total RNABF ($/Mcf) (6 = 3 / 4)
1	1st Quarter	($170,503)	403,102.7	Jun - Aug 2010	($0.4230)
2	2nd Quarter	$289,334	797,070.9	Sep - Nov 2010	$0.3630
3	3rd Quarter	($48,349)	5,025,598.8	Dec 2010 - Feb 2011	($0.0100)
4	4th Quarter	($26,843)	2,514,969.3	Mar - May 2011	($0.0110)
5	Total	$43,639	8,740,741.7		$0.0050

6	Annual Average Use Per Customer (Mcf)	72.5
7	Annual RNA Bill Impact	$0.36

3/ Page 6 of 6

RNABF - Revenue Normalization Adjustment Billing Factor

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment (RNA)
For the 12 Months Ending December 31, 2010

Residential Service

Line No. (1)	Month (2)	AQNR (3)	WAQBR (4)	Current Quarter RNA (5 = 3 - 4)
1	January	4,804,764	4,984,135	
2	February	4,727,581	4,722,675	
3	March	4,092,603	4,088,641	
4	**1st Quarter**	13,624,948	13,795,451	(170,503)
5	April	3,135,978	2,953,980	
6	May	2,141,568	2,037,951	
7	June	1,816,341	1,812,622	
8	**2nd Quarter**	7,093,887	6,804,553	289,334
9	July	1,709,830	1,729,794	
10	August	1,686,471	1,702,056	
11	September	1,647,870	1,660,670	
12	**3rd Quarter**	5,044,171	5,092,520	(48,349)
13	October	1,811,217	1,825,208	
14	November	2,486,776	2,389,446	
15	December	3,825,228	3,935,411	
16	**4th Quarter**	8,123,221	8,150,064	(26,843)
17	Total	$33,886,227	$33,842,588	$43,639

AQNR - Authorized Quarterly Non-Gas Revenue
WAQBR - Weather Adjusted Quarterly Booked Revenue

S. Mark Katko

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF
S. MARK KATKO
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF S. MARK KATKO

Q: Please state your name and business address.

A: My name is S. Mark Katko and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

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

A: I am employed by NiSource Corporate Services Company ("NCSC"). My title is Manager of Regulatory Strategy and Support. As Manager, my principal responsibilities include providing support in regulatory compliance filings and base rate cases as requested by the NiSource Inc. ("NiSource") gas distribution business unit, including Columbia Gas of Kentucky, Inc. ("Columbia" or "the Company").

Q: What is your educational background?

A: I received a Bachelor of Science in Business Administration degree, majoring in Accounting, in 1978 from The Ohio State University. I am a Certified Public Accountant (inactive) in the state of Ohio.

Q: What is your employment history?

A: I began my career with the Columbia Gas distribution companies in 1978 as a General Accountant in the Finance Department. I held various positions of increasing responsibility in the Accounting and Financial Planning sections of the Finance Department from 1978 to 2012, most recently as Manager of Budgets. I assumed my current position in the Regulatory Strategy and Support department in April 2012.

Q: Have you previously testified before any regulatory commission?

A: Yes. I have previously filed testimony with the Kentucky Public Service Commission.

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

A: I am responsible for the development of the cost of service and proposed revenue increase. As part of the cost of service analysis, my testimony supports Columbia's Operations and Maintenance ("O&M") expenses. I am also responsible for Schedules A, C, D, F, G, H, I and K. These schedules were prepared under my direction and supervision. I also sponsor and support Filing Requirements 11-a, 11-b, 12-c, 12-d, 12-h, , 12-j, 12-k, 12-l, 12-m, 12-n, 12-o, 12-p, 12-q, 12-r, 12-u, 13-a, 13-c, 13-d, 13-f, 13-g, 13-h, 13-i and 13-k.

Q: What is the test period in this proceeding?

A: Columbia is requesting an adjustment in rates based on a forecasted test period. The test period is the twelve months ended December 31, 2014. The financial data for the forecasted period is presented in the form of pro forma adjustments to a base period which is the twelve months ended August 31, 2013. The base period includes actual data for the period September 1, 2012 through February 28, 2013 and forecasted data for the period March 1, 2013 through August 31, 2013.

Q: What information is presented on Schedule A?

A: Schedule A reflects Columbia's Overall Financial Summary for the base period and forecasted test period. Schedule A, Line 8 shows the calculation of the revenue deficiency in this case of $16,595,510 for the forecasted test period. This amount represents the increase in revenue that is required by Columbia to earn an overall rate of return on rate base of 8.59%, the return recommended by Columbia witness Moul. On line 9, the requested revenue increase of $16,595,510 is the revenue that is supported by Columbia's proposed rates, and is the adjustment to revenue that Columbia is requesting in its Application.

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

A: Schedule C presents Columbia's jurisdictional Operating Income for the base period and forecasted test period and details how the Company derived the amount of the requested revenue increase. Schedule C-1 is the Operating Income Summary, Schedule C-2 is the Adjusted Operating Income Statement, Schedule C-2.1 is the annual Operating Revenues and Expenses by Accounts – Jurisdictional, and Schedule C-2.2 is the monthly Operating Revenues and Expenses by Accounts – Jurisdictional.

Q: Please explain Schedule C-1.

A: Schedule C-1 reflects Columbia's base period and forecasted test period Operating Income Summary. This schedule includes the forecasted test period operating income summarized at both current rates and proposed rates. The forecasted test period operating income at current rates is presented as pro forma adjustments to the base period. The revenue at proposed rates was developed by adding the revenue increase shown on Schedule A to the current forecasted period operating revenues. The related increase to expenses and taxes on the proposed revenue increase was subtracted from the current forecasted test period adjusted operating results to determine the forecasted operating income and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1 and is supported by Columbia witness Notestone.

Q: What is Schedule C-2?

A: Schedule C-2 shows the adjusted operating income statement for the base period and forecasted test period at current rates.

Q: Please explain Schedules C-2.1A and C-2.1B.

A: Schedule C-2.1A shows the detail of Columbia's unadjusted base period operating results and Schedule C-2.1B shows the unadjusted forecasted test period operating results. The operating results as shown on this schedule are listed by account and are summarized on Schedule C-2.

Q: Please explain Schedules C-2.2A and C-2.2B.

A: Schedules C-2.2A and C-2.2B show the information presented on Schedules C-2.1A and C-2.1B, respectively, by month.

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

A: Schedule D presents the summary of adjustments made to base period Operating Income to arrive at forecasted test period Operating Income. Schedule D-1 is the Summary of Utility Jurisdictional Adjustments to Operating Income by Major Accounts. Schedule D-2.1 shows the detailed adjustments made to revenue and gas purchase accounts. Schedule D-2.2 shows the detailed adjustments made to O&M accounts. Schedule D-2.3 shows the detailed adjustments made to Depreciation and Amortization and Taxes Other Than Income Taxes accounts. Schedule D-2.4 shows ratemaking adjustments that are being made to the forecasted test period and which are in addition to those adjustments on Schedules D-2.1 through D-2.3.

Q: What is the basis for the forecasted O&M expense included in the base period and forecasted test period net operating income?

A: The forecasted O&M expense included in the base and test periods is derived from the Company's most recent financial plan.

Q: How is O&M expense developed for Columbia's financial plan?

A: The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approach. The O&M budget serves as a key component of Columbia's overall financial plan at a high level and as a cost management tool for NiSource Gas Distribution ("NGD") business unit and Columbia management at a more detailed level.

NiSource establishes financial goals and objectives for the entire corporation based on its overall strategic planning objectives including business unit and operating company input. These goals and objectives are communicated to each of its business units and the NiSource Corporate Services Financial Planning and Analysis groups responsible for each unit's financial plans. It is the responsibility of these groups, working together, to ensure that: (1) its financial plans, including O&M expenses, are developed in accordance with corporate financial goals and objectives as well as certain specific corporate guidelines and assumptions; and (2) individual company operational and administrative requirements are addressed.

The O&M budget for Columbia is based on a grass roots concept in which individuals responsible for approving expenditures are also responsible for budgeting the expenditures. The process generally follows organizational responsibility. Department heads are responsible for overseeing the development of O&M budgets for all cost centers under their control. Budgets originate in operating center locations in the field and other departments representing the major business functions of the company; these budgets are combined with a corporate level budget to arrive at a total company budget.

Q: What is meant by the term corporate level budget?

A: The corporate level budget represents categories that are budgeted at a company, and not individual department level. This allows for each department to focus exclusively on the expenditures for which they are directly responsible. Examples of O&M expenses included at this level are employee benefits, benefits administration fees, audit fees, uncollectible accounts, management fee, corporate insurance, corporate incentive plan, long term incentive plan, regulatory amortizations, and revenue trackers.

Q: O&M expenses in Schedules C and D are shown by FERC, or general ledger, account as is required by the regulations regarding rate filings. Is this how these expenses are budgeted?

A: No. O&M budgets are developed at a cost element and activity level. Cost element defines the type of resources used or consumed in accomplishing the organization's goals and objectives, such as labor, materials, outside services, and many other categories. Cost elements are designed to permit uniform budgeting and cost reporting among all NGD companies. Activities describe the accomplishment or benefit derived from the expenditure, such as leak inspection and repair, cathodic protection, delinquent collections, and many other categories.

Q: How did Columbia convert O&M expenses budgeted by cost element and activity to FERC accounts filed in this proceeding?

A: Columbia allocated the budgeted O&M expenses by cost element to FERC accounts based on an historic trend. Specifically, Columbia looked at actual O&M expenses by cost element by FERC account for the twelve months ending December 31, 2012. A percentage of each FERC account charged to a particular cost element was calculated. This percentage was then applied to budgeted O&M expense for each cost element to arrive at an allocation of the cost element budget to FERC accounts for inclusion in the filing.

Q: What are the principal assumptions used in the development of the cost element budgets included in the forecasted test period O&M expenses?

A: Labor expense is based on projected headcount and wage increase assumptions. Specifically, Columbia is projecting 131 active full-time employees and an overall wage increase guideline of 3% for 2013 and 2014. Non-labor expenses start with the assumption that amounts are to be held relatively flat year to year reflecting a normal, ongoing level of expenses and further adjusted for activities or events that are reasonably expected to occur.

Q: Can you provide examples of such activities or events that have been taken into account in the development of the O&M expense budget?

A: Yes. The planned installation of automated meter reading devices scheduled over the course of 2014 is expected to result in outside services savings starting in the fourth quarter of 2014. Columbia is also anticipating additional expenses starting in mid-2013 related to compliance with new pipeline safety regulations under the federally mandated Distribution Integrity Management Program ("DIMP"). The estimated impact of this program has been taken into account in the development of outside services and public awareness advertising expenses, as well as in the budgeted headcount level used to develop labor expense mentioned previously.

Q: What other types of activities or events are specifically addressed in the O&M budget?

A: Postage expense, which is included in the Materials and Supplies cost element, reflects anticipated increases in postage rates. Uncollectible accounts expense is based on the latest estimate of net charge-offs as a percentage of residential revenue. Regulatory amortizations are budgeted at a level based on current approved amortizations of expenses previously deferred. Revenue trackers are budgeted at the same level as the corresponding revenue. In addition, corporate assumptions are provided to Columbia and other NiSource companies to be included in their respective financial plans.

Q: What are the corporate assumptions provided to Columbia?

A: Corporate assumptions provided to Columbia include several major categories. Employee benefits expenses are based on information provided by NiSource's independent actuary, AON Hewitt. Corporate insurance expenses are based on estimated property and casualty premium costs developed by NiSource's Corporate Insurance Department. Audit fees are based on estimates developed by NiSource Accounting. Telecommunications expenses are based on estimates developed by NiSource Information Technology. Management fee expenses are based on estimates of services to be performed by NCSC for Columbia. Benefits administration fees, long term incentive plan, and corporate incentive plan expenses are based on estimates developed by NiSource Human Resources; the corporate incentive plan is currently based on a target payout assumption. Expenses related to the implementation of a single general ledger and chart of accounts for all NiSource companies are based on estimates developed by the NiSource Financial Transformation group.

Q: What services are performed by NCSC for Columbia as included in the management fee?

A: Please refer to the testimony of Columbia witness Taylor for a list of the services performed by NCSC for Columbia and other NiSource companies.

Q: How is the management fee budget developed?

A: The management fee budget is based on the budgets developed by each NCSC department. Similar to Columbia's budgeting methodology, NCSC budgets its expenses by cost categories such as labor, materials, outside services and other expenses. In addition, each department is allocated a portion of NCSC's indirect costs, such as benefits, taxes, depreciation and other expenses to arrive at a fully loaded cost. The fully loaded budget is allocated to Columbia and other NiSource companies using an allocation basis or bases as determined by each department.

Q: What allocation bases are available to each department for allocating their budgets to NiSource companies?

A: Each allocation basis that is currently in effect is available to each department in allocating their budgets to NiSource companies. Please refer to the testimony of Columbia witness Taylor for an explanation of the Bases of Allocation. Also please refer to Filing Requirement 12-u for a description of each basis.

Q: Does the O&M expense budgeting methodology described in your testimony result in an accurate estimate of expenses to be incurred during the forecasted test period?

A: Yes. Please refer to Attachment SMK-1 included in this testimony for a comparison of actual versus the annual original O&M budget excluding trackers for the years 2008 through 2012. As with any budget, conditions may change over the course of a year, thus requiring adjustments to budgets subsequent to the original budget. Overall, this attachment indicates a high level of O&M budgeting accuracy by Columbia and, accordingly, provides a high level of confidence as to the accuracy of the O&M expenses included in the forecasted test period.

Q: Why have you excluded trackers from this comparison?

A: O&M expenses categorized as trackers are designed to match, or track, revenues related to specific programs that have been previously approved in order to ensure that there is no impact on net operating income for such programs. The accounting treatment generally allows expenses to be deferred as incurred and reclassified to expense when the recovery of program costs is recorded in revenue. While O&M tracker expense variances may be material, there is a corresponding offsetting revenue variance. For that reason, I have excluded trackers from the comparison so as not to distort the accuracy of the budget.

Q: What is the O&M expense level for the base period and forecasted test period?

A: O&M expense before ratemaking adjustments is $34,071,013 for the base period and $33,332,723 for the forecasted test period, a decrease of $738,290. Please refer to Attachment SMK-2 included in this testimony for a comparison of the two periods by cost element and explanations of the major drivers of the change. Also please refer to Schedule D-2.2 which provides additional detail regarding the adjustments between the two periods.

Q: Are you making any additional adjustments to O&M expense from what is shown on Attachment SMK-2?

A: Yes. O&M expense included on Attachment SMK-2 reflects Columbia's most recent forecast and represents the best estimate of costs to be incurred during a stated period. This is necessary for financial plan accuracy and cost management purposes. However, certain O&M expenses are treated differently for regulatory purposes. As the result of filing based on a fully forecasted test period, it is necessary to review financial plan O&M expenses further and make additional adjustments as needed. Schedule D-2.4 contains a listing of the ratemaking adjustments being made to forecasted test period O&M expenses, as well as to operating revenues and other operating expenses. These adjustments are summarized on Schedule C-2.

Q: **How are the income tax effects of these adjustments reflected?**

A: State and federal income taxes have been adjusted on Schedule E-1, which is supported by Columbia witness Fischer, to reflect changes resulting from the adjustments described in my testimony

Q: **Please explain Columbia's adjustment to regulatory commission expense requesting to recover costs incurred in preparing this case as shown on Schedule D-2.4.**

A: The adjustment to O&M expense for the estimated costs of developing this case is $675,000 and includes the costs of the legal notice, consultants retained, legal fees, and miscellaneous costs such as travel and supplies. This amount has been divided by 3 years, which reflects the proposed amortization period based on the average period between rate cases. The resulting adjustment is an increase to operating expense of $225,000 in the forecasted test period.

Q: **Please explain the adjustment to regulatory commission expense related to the annual Public Service Commission Fees assessment.**

A: The adjustment related to the annual PSC fees assessment is based on total forecasted test period Operating Revenues at current rates and the latest known assessment factor of 0.17540%. The resulting adjustment is a decrease to operating expense of $53,218 in the forecasted test period.

Q: **Please explain the adjustment to uncollectible accounts expense.**

A: Uncollectible accounts expense has been adjusted to reflect an appropriate level based on Columbia's current net charge-off percentage of 0.568963% which is applied to operating revenues in Schedule C as supported by Columbia witness Notestone. The resulting adjustment is a decrease to expense of $301,133 in the forecasted test period.

Q: **What does the separate adjustment for large volume uncollectible accounts represent?**

A: Uncollectible expense related to large volume accounts is accounted for separately due to its unique pattern. The forecasted test period has been decreased by $14,107 to reflect a five year average of actual expense.

Q: **What is the adjustment related to ASC 712 Post-Employment Benefits?**

A: Accounting Standards Codification (ASC) 712, formerly referred to as Statement of Financial Accounting Standards (SFAS) 112, defines the calculation of expense representing the estimated cost of providing medical, dental and life insurance to individuals on disability up until they are age 65. Each year, Columbia makes an annual adjustment to the liability. This amount can vary greatly year to year and has not historically been included in Columbia's forecasts. The forecasted test period has been increased by $9,770 to reflect a five year average of actual expense.

Q: Why has Columbia requested recovery of costs related to other post-retirement benefits billed from NCSC?

A: In June 2011, Columbia was billed $324,621 from NCSC representing the difference between the level of NCSC's accruals under ASC 715, formerly referred to as SFAS 106, and the amounts it had expensed based on the level of claims it had paid over a period of many years. Columbia capitalized $29,887 and recorded the remaining $294,734 to a regulatory asset based on the final order in Case No. 2011-00422. This amount has been divided by 5 years, which is the proposed amortization period. The resulting adjustment is an increase to operating expense of $58,947 in the forecasted test period.

Q: Please explain the adjustment for tracker expense accounts.

A: The adjustment to tracker expense is required to match expense with revenue recoveries for the Energy Assistance Program and Energy Efficiency and Conservation riders that are included in Operating Revenues in Schedule C. The resulting adjustment is a decrease to operating expense of $307,699.

Q: Why did Columbia remove certain O&M expenses as non-recoverable?

A: As explained earlier, the O&M budget included in Columbia's financial plan needs to be all inclusive to ensure overall accuracy and support cost management activities. Included in budgeted O&M expenses are items that have historically been treated as non-recoverable for ratemaking purposes. These include certain expenses related to reimbursements to employees, lobbying, promotional advertising, other business promotion, and dues and memberships. Adjustments 9, 10, and 11 on Schedule D-2.4 recognize this treatment. The resulting adjustment is a decrease to operating expense of $299,658.

Q: What is the basis for the depreciation and amortization expense included in the base period and forecasted test period net operating income?

A: Depreciation expense included in the base period is based on actual expense for September 2012 through February 2013 and estimated depreciation expense for March through August 2013 based on current depreciation rates and forecasted plant in service by month. For the forecasted test period, depreciation expense is based on proposed depreciation rates filed in this case by Columbia witness

Spanos and forecasted plant in service by month. The forecasted plant in service in both the base period and forecasted test period is supported by Columbia witness Notestone. Amortization expense included in the base period and forecasted test period relates to specific intangible assets with identifiable in-service dates and lives. Amortization of these assets is normally recorded on a straight-line basis over the individual asset's life.

Q: Is an additional adjustment to depreciation and amortization expense being made on Schedule D-2.4?

A: No.

Q: What is the basis for the taxes other than income included in the base period and forecasted test period net operating income on Schedule C?

A: Property taxes are based on the latest estimated effective tax rate and applying it to the latest actual assessed value further adjusted to reflect estimated additions and retirements to property, plant, and equipment over the planning period. Property taxes on gas storage are based on the latest estimated effective tax rate and applying it to the latest actual West Virginia assessed value. Payroll taxes are based on an historic trend of actual payroll expense to actual labor expense and applying the resulting percentage to projected labor expense.

Q: Is an additional adjustment to taxes other than income being made on Schedule D-2.4?

A: Yes. Property tax expense has been adjusted to reflect projected calendar year 2013 net plant additions and the projected gas storage balance at December 31, 2013 as included in this rate case. The resulting adjustment is an increase to property tax expense of $2,084. Payroll tax expense has been adjusted to reflect forecasted test period labor expense as included in this rate case. The resulting adjustment is an increase to payroll tax expense of $47,026.

Q: Please describe the remaining schedules for which you are responsible.

A: Schedule F is a listing of organization membership dues; initiation fees; expenditures at country clubs; charitable contributions; marketing, sales, and advertising expenditures; professional service expenses; civic and political activity expenses; expenditures for employee parties and outings; employee gift expenses; and rate case expenses for the base period and forecasted test period. Schedule G is an analysis of payroll costs including wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title. Schedule H shows the calculation of the gross revenue conversion factor for the forecasted test period. Schedule I provides comparative income statements, revenue statistics, and sales statistics for the 5 most recent calendar years from the application filing date, the base period, the forecasted test period, and 2 calendar years beyond the forecast period. Schedule K provides comparative financial data and earnings measures for the 10 most recent calendar years, the base period, and the forecasted test period.

Q: Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Steven Mark Katko, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Steven Mark Katko

Steven Mark Katko

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by Steven Mark Katko on this the 23RD day of May, 2013.

NOTARIAL SEAL STATE OF OHIO

CHERYL A. MacDONALD
Notary Public, State of Ohio
My Commission Expires
March 26, 2017

Notary Public

My Commission expires: MARCH 26, 2017

Columbia Gas of Kentucky, Inc.
Operation and Maintenance Expenses
Actual v. Original Budget Excluding Trackers
2008 - 2012
($000)

Year	Original Budget	Actual	Increase (Decrease)	% Variance	Major Variance by Category:
2008	28,302	27,733	(569)	-2.0%	management fee $(959); employee benefits $(673); uncollectibles $1,147.
2009	30,205	30,799	594	2.0%	management fee $434; employee benefits $384; labor $356; outside services $(654).
2010	32,304	30,282	(2,022)	-6.3%	uncollectibles - $(2,068).
2011	31,578	29,820	(1,758)	-5.6%	uncollectibles - $(1,345); employee benefits $(882)
2012	30,890	31,254	364	1.2%	labor $694; employee benefits $457; uncollectible accounts $(650).
Cumulative	153,279	149,888	(3,391)	-2.2%	

Columbia Gas of Kentucky, Inc.
Operation and Maintenance Expenses Comparison
For the Base Period 12 Months Ending August 31, 2013 and the Forecasted Period 12 Months Ending December 31, 2014

	Base Period	Schedule D-2.2 Adjustments	Forecasted Period Before Ratemaking Adjustments	% Change Forecasted v. Base Period	Major Drivers of Change:
Labor	7,422,952	131,442	7,554,394	1.77%	Wage and headcount increases partially offset by decreased incentive plans.
Employee Benefits	3,128,530	(1,005,132)	2,123,398	-32.13%	Primarily decreased pension and ASC 712 annual accrual.
Materials and Supplies	1,530,224	(86,293)	1,443,931	-5.64%	Primarily decreased purchase of hand tools (based period includes increased level for new hires) partially offset by increased postage.
Outside Services	5,580,777	(442,273)	5,138,504	-7.92%	Primarily AMR savings reflected in forecasted period, decreased demand side management (EECP), and decreased contractor work; partially offset by increased DIMP related expenses.
Rents and Leases	304,918	(2,557)	302,361	-0.84%	
Corporate Insurance	792,748	49,042	841,790	6.19%	Primarily increased excess liability premiums due to market conditions and property premiums due to rising property values and higher global insurance market rates.
Employee Expenses	349,340	3,823	353,163	1.09%	
Company Memberships	86,013	1,262	87,275	1.47%	
Utilities Used in Company Operations	424,449	11,733	436,182	2.76%	
NCS Management Fee	12,352,361	381,275	12,733,636	3.09%	Primarily increased labor, legal, depreciation and taxes partially offset by decreased incentive plans and employee benefits.
Uncollectible Accounts - Non-Gas Costs	116,499	338,501	455,000	290.56%	Primarily projected increase in net charge-offs (2012 calendar year was abnormally low).
Uncollectible Accounts - Gas Costs	159,009	48,991	208,000	30.81%	
Miscellaneous Revenue Adjustments	(201,813)	103,160	(98,653)	-51.12%	Decreased facilities damages recoveries due to proactive damage prevention efforts.
Injuries and Damages	124,803	(21,891)	102,912	-17.54%	Forecasted Period is based on historic average due to varying and unpredictable activity year to year.
Miscellaneous and Other Expenses	258,183	7,486	265,669	2.90%	
Regulatory Amortizations	404,935	(14,827)	390,108	-3.66%	Rate case amortization ended in October 2012.
Advertising	243,034	24,662	267,696	10.15%	Increased public awareness (DIMP) partially offset be decreased demand side management (EECP).
Clearing Accounts (Fleet)	1,163,119	95,493	1,258,612	8.21%	Primarily increased fuel and lease costs.
Deferred Credit	(1,523,164)	537,926	(985,238)	-35.32%	Decreased deferred demand side management (EECP) expenditures (primarily outsides services and advertising).
Total Non-Tracked	32,716,917	161,823	32,878,740	0.49%	
Uncollectible - EAP Tracker	455,556	(1,573)	453,983	-0.35%	Offset in revenue.
Other Revenue - EECP Tracker	898,540	(898,540)	-	-100.00%	
Total O&M Expense	34,071,013	(738,290)	33,332,723	-2.17%	

Chad E. Notestone

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF
CHAD E. NOTESTONE
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF CHAD E. NOTESTONE

Q: Please state your name and business address.

A: My name is Chad E. Notestone and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

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

A: I work for NiSource Corporate Services Company and my current title is Lead Regulatory Analyst. In this role, I primarily provide regulatory services and support for NiSource's gas distribution subsidiary companies. Specifically, I provide support for various rate filings and compliance filings made with the state regulatory commissions. My other duties include creating reports and performing studies that support accounting, auditing, and financial planning matters.

Q: What is your educational background?

A. I received a Bachelor of Business Administration degree, majoring in Finance, from Ohio University in 2006. Also, I am currently pursuing a Master of Business Administration degree from Ohio University. My expected completion date of the M.B.A. degree program is in August of 2013.

Q: Please describe your employment history.

A: Prior to my employment with NiSource, I worked for the private accounting firm Jones, Cochenour & Co. as a Staff Auditor. I began my career with NiSource Corporate Services Company in 2007 as a Regulatory Analyst. I was promoted to Senior Regulatory Analyst in 2009 and I remained in this role until being promoted to my current position in 2013. In addition to my work experience, I have attended a variety of public utility accounting and ratemaking seminars sponsored by trade associations.

Q: Have you previously testified before any regulatory commission?

A: No.

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

A: In the first section of my testimony, I am supporting the development of the revenues for both the base period and forecasted test period as presented in Schedules D-2.1 and M. Additionally, I am sponsoring the typical bill comparisons at current and proposed rates shown in Schedule N. The second part of my testimony discusses the development of Rate Base as presented in Schedule B. Specifically, I support Schedules B-1, B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-4, B-5, B-5.1, and B-7, excluding B-6 for both the base period and the forecasted test period. I also sponsor Filing Requirement 12-h-12.

Q: What are the test years that you will be addressing in this testimony?

A: I will be addressing the twelve month period ending August 31, 2013 as the base period, as well as the twelve months ending December 31, 2014 as the forecasted test period.

BILLING DETERMINANTS / REVENUE SCHEDULES

Q: What process is undertaken to produce the number of bills used to calculate revenue in this case?

A: The detail supporting number of bills used for the forecasted test period is found in workpaper WPM-B. Forecasted active customer counts are first determined on a total company basis by customer class by type of service (sales/CHOICE/transportation) by month in Columbia's forecast supported by Columbia witness Gresham. Large customers individually forecasted by the Large Customer Relations ("LCR") group are identified separately from the total forecast. The remaining non-LCR customer counts in the forecast are then spread for each month of the test period by type of service by customer class by rate schedule based on the latest twelve months of historical experience ending February 28, 2013. Bill counts for the LCR customers are adjusted to reflect customers who are expected to either discontinue or add service during the forecasted period as shown in workpaper WPB-D. The bills are accumulated based upon which rate schedule the customer was on at February 28, 2013. The spread and accumulation of bills is computed using Columbia's FORTRAN based revenue pricing software.

Additionally, an adjustment is made to the number of forecasted bills to reflect final billed customers because the forecast is based on projected active customers. In the months that a final bill is issued, the customers are coded inactive and are not counted for the month even though they are billed a customer charge for their final month of service. Columbia considers the historical final bill counts to be representative of what can be expected during the forecasted test period. As a result, final bills are added to the active bills used in the forecast to price revenue in this case. Forecasted test year bills are then taken from WPM-B and used to price customer charge revenue at current rates in Schedule M-2.2 and proposed rates in Schedule M-2.3.

The total customer counts for the base period are determined using six months of actual customer bills from September 2012 through February 2013 and six months of forecasted bills through August 2013.

Q: **What process is used to develop the throughput in Mcf used to calculate revenue in this case?**

A: Work paper WPM-C details the throughput in Mcf used to calculate revenue in this case. Similar to the methodology use to produce the number of bills, forecasted Mcf are first determined on a total company basis by customer class by type of service by month in Columbia's forecast supported by witness Gresham. Forecasted throughput associated with LCR customers is identified separately from the total forecast based upon the individual large customer forecast performed by the LCR group. The remaining non LCR throughput is then spread for each month of the forecasted test period by type of service by customer class by rate schedule based on the latest twelve months of historical experience ending February 28, 2013. Throughput is accumulated based upon which rate schedule the customers were on at February 28, 2013. Computations pertaining to the spread and accumulation of the volumes also are performed using the Columbia's FORTRAN based revenue pricing software. Adjustments resulting from LCR customers either discontinuing or adding service during the forecasted test year are show in workpaper WPM-D. Additionally, workpaper WPM-D reflects any anticipated significant usage changes for LCR customers during the forecasted test period. Adjustment volumes in workpaper WPM-D are then recorded in workpaper WPM-C to arrive at the total adjusted volume forecast used to price revenue for the period.

The throughput for the base period is determined using six months of actual volumes from September 2012 through February 2013 and six months of forecasted volumes through August 2013.

Q: How were the non-LCR commercial and industrial forecasted volumes in WPM-C split by rate block?

A: The spread of non LCR commercial and industrial throughput is performed at the individual customer level by month based on historical experience for the twelve months ended February 28, 2013. Each customer's forecasted monthly throughput is then split among the rate blocks pertaining to that customer's rate schedule. For example, volumes for a sales rate schedule General Service Other ("GSO") customer who is projected to use 500 Mcf in January are split according to the rate schedule GSO rate blocks of First 50 Mcf, Next 350 Mcf, Next 600 Mcf and Over 1,000 Mcf. In this example, 50 Mcf is put in the first block, 350 Mcf in the second block, and 100 Mcf in the third rate block totaling the 500 Mcf projected for January. Individual customers' projected monthly usage by rate block is then aggregated and shown in workpaper WPM-C.

Q: How was the gas cost revenue calculated for the forecasted test period?

A: Columbia's most recent Commission-approved gas cost recovery rate, effective February 28, 2013, was applied to volumes (Mcf) for each month of the forecasted test period based on rate class. Calculations are shown on workpaper WPM-A.

Q: How was the forecasted test period revenue at current rates developed in Schedule M-2.2?

A: Forecasted test period bills from workpaper WPM-B and forecasted test period volumes from workpaper WPM-C are recorded in Schedule M-2.2 by month by rate class. Forecasted test period bills and volumes for each month for each rate class are then multiplied by the applicable current rates in column C.

Q: How was the forecasted test period revenue at proposed rates developed in Schedule M-2.3?

A: Forecasted test period bills and volumes in Schedule M-2.3 are identical to Schedule M-2.2. Forecasted test period bills and volumes for each month for each rate class are then multiplied by the applicable proposed rates in column C. An adjustment is applied to Account 487 to reflect an expected increase in forfeited discounts attributable to the proposed rates.

Q: Please describe Schedule M-2.1.

A: Schedule M-2.1 shows the comparison of revenue at current rates and revenue at proposed rates by rate classification. Columns B (Forecasted Bills), C (Forecasted Mcf), and D (Revenue at Current Rates) are recorded from Schedule M-2.2. Column G (Revenue at Proposed Rates) is recorded from Schedule M-2.3. Column E (D-2.4 Rate Making Adjustment) shows an adjustment to the gas cost uncollectible revenue at current rates to reflect the revised charge-off percentage used in this case. The difference between revenue at proposed rates and revenue at current rates is shown in column H with the corresponding percentage change shown in column I.

Q: Please describe Schedule M.

A: Schedule M summarizes total forecasted revenue by customer class by month at both current and proposed rates. Revenue at current rates is summarized from Schedule M-2.2 and revenue at proposed rates is summarized from Schedule M-2.3.

Q: How was Schedule N (Typical Bill Comparison) developed?

A: Monthly usage levels were selected in order to give a representative effect of the change in a typical monthly bill based on proposed rates as compared to current rates. Tariff sales rate schedules were compared with and without gas cost. Customer and commodity charges were compared for transportation rate schedules. Attachment CEN-1 provides a monthly bill comparison for residential customers at current and proposed rates.

RATE BASE

Q: Please describe the rate base information presented in Schedule B.

A: The information shown on schedule B-1 is the jurisdictional rate base summary proposed in this proceeding. The forecasted test period rate base of $203,298,499 was developed using thirteen month average balances of forecasted plant-in-service, reserve for accumulated depreciation and amortization, accumulated deferred income taxes and deferred credits, as well as other working capital items from December 31, 2013 through December 31, 2014, unless noted otherwise. The plant-in-service and reserve for accumulated depreciation and amortization for the test periods are summarized on Schedules B-2, B-3, and B-4. Forecasted monthly capital additions are based on Columbia's capital program as supported in the testimony of Columbia witness Belle. The forecasted monthly reserve for accumulated depreciation balances are developed based on the depreciation rates provided by Columbia witness Spanos. Schedule B-5 shows the allowance for working capital. Columbia witness Fischer provides support for the development of accumulated deferred income taxes and other deferred credits shown on Schedule B-6. Schedule B-7 reflects the jurisdictional allocation factors.

Q: Why is a thirteen month average balance utilized for rate base?

A: Columbia's rate filing is supported by a fully forecasted test year, and is therefore required by Section 16 (11)(c) of 807 KAR 5:001, also referred to as Filing Requirement 11-c, of the Commission's regulations to use a thirteen month average net investment rate base.

Q. Please describe in detail the individual supporting schedules for Schedule B.

A. Schedule B-2 shows Columbia's plant-in-service investment by major property grouping for both the base period and the forecasted test period. Schedules B-2.1 through B-2.7 provide detail of the major property groupings by gas plant account and show the plant additions and retirements for each account during the test periods.

Schedule B-3 shows the accumulated depreciation and amortization balances by gas plant account for both the base period and the forecasted test period.

Workpaper WPB-2.2 provides the supporting calculations for both the plant-in-service and reserve for accumulated depreciation and amortization balances throughout the forecasted period.

Schedule B-4 shows the amount of construction work-in-progress ("CWIP") as of February 28, 2013. Columbia has identified $50,373 of the total CWIP balance as in-service but not yet classified to the proper FERC account 106. Therefore, this amount is included for recovery in rate base.

Q: How was the forecasted test period plant-in-service developed?

A: Calculations showing the development of the forecasted monthly plant-in-service balances are found in WPB-2.2. Actual per books plant-in-service as of February 28, 2013 in Accounts 101, 106 and the in-service portion of Account 107 is the starting point for the forecast. Budgeted plant additions were then added by month and budgeted retirements were deducted by month throughout the forecasted test period. Monthly budgeted capital additions were based on Columbia's capital program discussed in the testimony of Columbia witness Belle. Projected plant retirements were based on a three year average level of actual retirements recorded 2010 through 2012. Projected plant additions and retirements were then increased by 8.2 percent to reflect Columbia's five-year history of exceeding its original capital expenditure forecasts.

Q: How was the forecasted test year reserve for accumulated depreciation and amortization developed?

A: Calculations showing the development of the forecasted monthly reserve for accumulated depreciation and amortization balances are found in WPB-2.2. Details supporting the monthly amortization expense are found in WPB-2.2a for intangible plant that is subject to amortization. Actual per books accumulated depreciation and amortization as of February 28, 2013 is the starting point for the forecast. For each month of the forecast, the accumulated reserve is increased by the projected depreciation and amortization expense and reduced by the projected retirements and cost of removal. The budgeted depreciation accruals are based on the depreciation rates supported by witness Spanos.

Q: **How would you describe the calculation of cash working capital and other working capital allowances as shown on Schedule B-5?**

A: The total working capital requirement of $43,526,144 is summarized on Schedule B-5, Line 6. This is made up of Cash Working Capital shown on Line 1, Fuel Stock shown on Line 2, Materials and Supplies shown on Line 3, Gas Stored Underground shown on Line 4, and Prepayments shown on Line 5. Working capital associated with Materials and Supplies and Prepayments were both determined based on the actual thirteen month average of per book balances ending February 28, 2013. Columbia does not anticipate a significant change in the amount of materials and supplies and prepayments during the forecasted test period. The working capital component of Gas Stored Underground was calculated by taking the average of the projected thirteen month Gas Stored Underground balances ending December 31, 2014.

Q: How does Columbia value its gas stored inventory?

A: Columbia currently utilizes Last-in, First-out ("LIFO") inventory accounting to value its gas stored inventory on its books in accordance with Generally Accepted Accounting Principles ("GAAP"). Workpaper WPB-5.3 shows the calculations of the projected monthly storage asset balances using this same pricing methodology. The LIFO procedure prices gas withdrawals and injections using an anticipated average annual commodity gas price. This rate is trued up periodically throughout the year until calendar year-end when it is trued up to an actual average annual commodity rate for the calendar year January through December. To the extent injections are greater than withdrawals for a calendar year, then a LIFO layer is created and tracked. This vintage LIFO layer is identified with a net volume injected, a rate per volume, and a resulting dollar balance. On the other hand, if withdrawals are greater than injections for the calendar year, then prior LIFO layers are depleted starting with the most recent year layer. As shown in WPB-5.3 Columbia is projecting volumetric net withdrawals for both calendar years 2013 and 2014 along with average commodity rates per Mcf of $4.0490 and $4.5840, respectively.

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

A: No. Columbia excluded from working capital the portion of prepayments recorded on the books related to Commission fees.

Q: How was the Cash Working Capital allowance developed?

A: Cash Working Capital is calculated by taking total operation and maintenance expenses for the twelve months ended December 31, 2014 (excluding gas costs) as supported by Columbia witness Katko and multiplying by 1/8 or 12.5%. Traditionally, this formula method has been used by Columbia and accepted by the Commission in Columbia's previous rate filings.

Q: Did Columbia include customer advances for construction as a reduction to rate base?

A: Yes. Since January 2000, a credit is made to gas plant-in-service in recognition of customer advances. As such, a reduction to rate base has been included for post-1999 customer advances by including net plant-in-service per books. Prior to January 2000, a credit for customer advances was included in Account 252-15560. As of February 28, 2013, the customer advances balance in the Account 252-15560 is zero. The budgeted capital expenditures supported by witness Belle also are net of projected customer advances. Therefore, the plant-in-service claimed in this proceeding reflects deductions related to customer advances.

Q: Please explain Schedule B-7.

A: This schedule identifies the allocation factors used to determine the jurisdictional percentage of gas plant costs applicable to the calculation of the gas rate increase requested in this application. Columbia does not have any non-jurisdictional gas customers within its service territory. Therefore, this schedule indicates that 100% of Columbia's costs are jurisdictional in nature and are appropriate to include for recovery in this application.

Q: Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates	)	Case No. 2013-00167
of Columbia Gas of Kentucky, Inc.	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Chad E. Notestone, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Chad Notestone

Chad E. Notestone

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by Chad E. Notestone on this the 22ND day of May, 2013.

NOTARIAL SEAL STATE OF OHIO

CHERYL A. MacDONALD
Notary Public, State of Ohio
My Commission Expires
March 26, 2017

Notary Public

My Commission expires: MARCH 26, 2017

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Average General Service Residential (GSR) Total Bill by Month
For the 12 Months Ending December 31, 2014

Month (1)	GSR Customers (2)	GSR Normalized Mcf (3)	Usage Per Customer Mcf/Cust (4)=(3)/(2)	Current Bill (5)	Proposed Bill (6)	Difference (7)=(6)-(5)	Percent Increase (Decrease) (8)=(7)/(5)
Jan	93,183	1,319,015.8	14.2	$ 99.39	$ 111.93	$ 12.54	12.60%
Feb	93,332	1,250,171.9	13.4	$ 94.53	$ 106.65	$ 12.12	12.80%
Mar	93,143	948,388.9	10.2	$ 75.11	$ 85.55	$ 10.44	13.90%
Apr	92,524	581,454.2	6.3	$ 51.42	$ 59.81	$ 8.39	16.30%
May	91,754	247,810.5	2.7	$ 29.56	$ 36.08	$ 6.52	22.10%
Jun	91,018	126,905.6	1.4	$ 21.67	$ 27.50	$ 5.83	26.90%
Jul	90,404	85,931.8	1.0	$ 19.24	$ 24.85	$ 5.61	29.20%
Aug	90,152	83,945.6	0.9	$ 18.63	$ 24.20	$ 5.57	29.90%
Sep	90,074	87,935.1	1.0	$ 19.24	$ 24.85	$ 5.61	29.20%
Oct	90,392	139,834.1	1.5	$ 22.28	$ 28.16	$ 5.88	26.40%
Nov	91,352	369,638.8	4.0	$ 37.46	$ 44.65	$ 7.19	19.20%
Dec	92,206	857,359.4	9.3	$ 69.63	$ 79.61	$ 9.98	14.30%
Annual Total	1,099,534	6,098,391.7	65.9	$ 558.16	$ 653.84	$ 95.68	17.14%

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Average Small Volume Gas Transportation Residential (GTR) Total Bill by Month
For the 12 Months Ending December 31, 2014

Month (1)	GTR Customers (2)	GTR Normalized Mcf (3)	Usage Per Customer Mcf/Cust (4)=(3)/(2)	Current Bill \ 1 (5)	Proposed Bill \ 1 (6)	Difference (7)=(6)-(5)	Percent Increase (Decrease) (8)=(7)/(5)
Jan	26,761	410,000.0	15.3	$ 42.97	$ 56.64	$ 13.67	31.80%
Feb	26,804	389,000.0	14.5	$ 41.42	$ 54.64	$ 13.22	31.90%
Mar	26,750	295,000.0	11.0	$ 34.61	$ 45.86	$ 11.25	32.50%
Apr	26,572	181,000.0	6.8	$ 26.42	$ 35.32	$ 8.90	33.70%
May	26,351	77,000.0	2.9	$ 18.82	$ 25.53	$ 6.71	35.70%
Jun	26,140	39,000.0	1.5	$ 16.09	$ 22.02	$ 5.93	36.90%
Jul	25,964	27,000.0	1.0	$ 15.12	$ 20.77	$ 5.65	37.40%
Aug	25,891	26,000.0	1.0	$ 15.12	$ 20.77	$ 5.65	37.40%
Sep	25,869	27,000.0	1.0	$ 15.12	$ 20.77	$ 5.65	37.40%
Oct	25,960	44,000.0	1.7	$ 16.48	$ 22.52	$ 6.04	36.70%
Nov	26,236	115,000.0	4.4	$ 21.74	$ 29.30	$ 7.56	34.80%
Dec	26,481	267,000.0	10.1	$ 32.84	$ 43.60	$ 10.76	32.80%
Annual Total	315,779	1,897,000.0	71.2	$ 296.75	$ 397.74	$ 100.99	34.03%

_1 Excludes cost of Marketer supplied gas

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Average General Service Residential (GSR) Total Bill by Month at Current and Proposed Rates
For the 12 Months Ending December 31, 2014

Current Rates

Month	GSR Customers	GSR Normalized Mcf	Usage Per Customer Mcf/Cus	Customer Charge Revenue	Volumetric Delivery Charge Revenue @ $1.8715/Mcf	Total Delivery Charge Revenue	AMRP Revenue $1.06/Bill	EECP Charge Revenue $(.24)/Bill	Volumetric EAP Charge Revenue @ $0.0615/Mcf	Volumetric R&D Charge Revenue @ $0.015/Mcf	Volumetric GCA Charge Revenue @ $4.0634/Mcf	Volumetric Uncollectible Charge Revenue @ $0.0603/Mcf	Total Bill
(1)	(2)	(3)	(4=3/2)	(5)	(6)	(7=5+6)	(8)	(9)	(10)	(11)	(12)	(13)	(14 = 7 thru 13)
				($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
Jan	93,183	1,319,015.8	14.2	12.35	26.58	38.93	1.06	(0.24)	0.87	0.21	57.70	0.86	99.39
Feb	93,332	1,250,171.9	13.4	12.35	25.08	37.43	1.06	(0.24)	0.82	0.20	54.45	0.81	94.53
Mar	93,143	948,388.9	10.2	12.35	19.09	31.44	1.06	(0.24)	0.63	0.15	41.45	0.62	75.11
Apr	92,524	581,454.2	6.3	12.35	11.79	24.14	1.06	(0.24)	0.39	0.09	25.60	0.38	51.42
May	91,754	247,810.5	2.7	12.35	5.05	17.40	1.06	(0.24)	0.17	0.04	10.97	0.16	29.56
Jun	91,018	126,905.6	1.4	12.35	2.62	14.97	1.06	(0.24)	0.09	0.02	5.69	0.08	21.67
Jul	90,404	85,931.8	1.0	12.35	1.87	14.22	1.06	(0.24)	0.06	0.02	4.06	0.06	19.24
Aug	90,152	83,945.6	0.9	12.35	1.68	14.03	1.06	(0.24)	0.06	0.01	3.66	0.05	18.63
Sep	90,074	87,935.1	1.0	12.35	1.87	14.22	1.06	(0.24)	0.06	0.02	4.06	0.06	19.24
Oct	90,392	139,834.1	1.5	12.35	2.81	15.16	1.06	(0.24)	0.09	0.02	6.10	0.09	22.28
Nov	91,352	369,638.8	4.0	12.35	7.49	19.84	1.06	(0.24)	0.25	0.06	16.25	0.24	37.46
Dec	92,206	857,359.4	9.3	12.35	17.40	29.75	1.06	(0.24)	0.57	0.14	37.79	0.56	69.63
Total	1,099,534	6,098,391.7	65.9	148.20	123.33	271.53	12.72	(2.88)	4.06	0.98	267.78	3.97	558.16

Proposed Rates

Month	GSR Customers	GSR Normalized Mcf	Usage Per Customer Mcf/Cus	Customer Charge Revenue	Volumetric Delivery Charge Revenue @ $2.4322/Mcf	Total Delivery Charge Revenue	AMRP Revenue $0.00/Bill	EECP Charge Revenue $(.24)/Bill	Volumetric EAP Charge Revenue @ $0.0615/Mcf	Volumetric R&D Charge Revenue @ $0.015/Mcf	Volumetric GCA Charge Revenue @ $4.0634/Mcf	Volumetric Uncollectible Charge Revenue @ $0.0243/Mcf	Total Bill
(1)	(2)	(3)	(4=3/2)	(5)	(6)	(7=5+6)	(8)	(9)	(10)	(11)	(12)	(13)	(14 = 7 thru 13)
				($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
Jan	93,183	1,319,015.8	14.2	18.50	34.54	53.04	0.00	(0.24)	0.87	0.21	57.70	0.35	111.93
Feb	93,332	1,250,171.9	13.4	18.50	32.59	51.09	0.00	(0.24)	0.82	0.20	54.45	0.33	106.65
Mar	93,143	948,388.9	10.2	18.50	24.81	43.31	0.00	(0.24)	0.63	0.15	41.45	0.25	85.55
Apr	92,524	581,454.2	6.3	18.50	15.32	33.82	0.00	(0.24)	0.39	0.09	25.60	0.15	59.81
May	91,754	247,810.5	2.7	18.50	6.57	25.07	0.00	(0.24)	0.17	0.04	10.97	0.07	36.08
Jun	91,018	126,905.6	1.4	18.50	3.41	21.91	0.00	(0.24)	0.09	0.02	5.69	0.03	27.50
Jul	90,404	85,931.8	1.0	18.50	2.43	20.93	0.00	(0.24)	0.06	0.02	4.06	0.02	24.85
Aug	90,152	83,945.6	0.9	18.50	2.19	20.69	0.00	(0.24)	0.06	0.01	3.66	0.02	24.20
Sep	90,074	87,935.1	1.0	18.50	2.43	20.93	0.00	(0.24)	0.06	0.02	4.06	0.02	24.85
Oct	90,392	139,834.1	1.5	18.50	3.65	22.15	0.00	(0.24)	0.09	0.02	6.10	0.04	28.16
Nov	91,352	369,638.8	4.0	18.50	9.73	28.23	0.00	(0.24)	0.25	0.06	16.25	0.10	44.65
Dec	92,206	857,359.4	9.3	18.50	22.62	41.12	0.00	(0.24)	0.57	0.14	37.79	0.23	79.61
Total	1,099,534	6,098,391.7	65.9	222.00	160.29	382.29	0.00	(2.88)	4.06	0.98	267.78	1.61	653.84

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Average Small Volume Gas Transportation Residential (GTR) Total Bill by Month at Current and Proposed Rates
For the 12 Months Ending December 31, 2014

Current Rates

Month	GTR Customers	GTR Normalized Mcf	Usage Per Customer Mcf/Cus	Customer Charge Revenue	Volumetric Delivery Charge Revenue @ $1.8715/Mcf	Total Delivery Charge Revenue	AMRP Revenue $1.06/Bill	EECP Charge Revenue $(.24)/Bill	Volumetric EAP Charge Revenue @ $0.0615/Mcf	Volumetric R&D Charge Revenue @ $0.015/Mcf	Volumetric GCA Charge Revenue @ $0.0000/Mcf	Volumetric Uncollectible Charge Revenue @ $0.0000/Mcf	Total Bill
(1)	(2)	(3)	(4=3/2)	(5)	(6)	(7=5+6)	(8)	(9)	(10)	(11)	(12)	(13)	(14 = 7 thru 13)
				($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
Jan	26,761	410,000.0	15.3	12.35	28.63	40.98	1.06	(0.24)	0.94	0.23	0.00	0.00	42.97
Feb	26,804	389,000.0	14.5	12.35	27.14	39.49	1.06	(0.24)	0.89	0.22	0.00	0.00	41.42
Mar	26,750	295,000.0	11.0	12.35	20.59	32.94	1.06	(0.24)	0.68	0.17	0.00	0.00	34.61
Apr	26,572	181,000.0	6.8	12.35	12.73	25.08	1.06	(0.24)	0.42	0.10	0.00	0.00	26.42
May	26,351	77,000.0	2.9	12.35	5.43	17.78	1.06	(0.24)	0.18	0.04	0.00	0.00	18.82
Jun	26,140	39,000.0	1.5	12.35	2.81	15.16	1.06	(0.24)	0.09	0.02	0.00	0.00	16.09
Jul	25,964	27,000.0	1.0	12.35	1.87	14.22	1.06	(0.24)	0.06	0.02	0.00	0.00	15.12
Aug	25,891	26,000.0	1.0	12.35	1.87	14.22	1.06	(0.24)	0.06	0.02	0.00	0.00	15.12
Sep	25,869	27,000.0	1.0	12.35	1.87	14.22	1.06	(0.24)	0.06	0.02	0.00	0.00	15.12
Oct	25,960	44,000.0	1.7	12.35	3.18	15.53	1.06	(0.24)	0.10	0.03	0.00	0.00	16.48
Nov	26,236	115,000.0	4.4	12.35	8.23	20.58	1.06	(0.24)	0.27	0.07	0.00	0.00	21.74
Dec	26,481	267,000.0	10.1	12.35	18.90	31.25	1.06	(0.24)	0.62	0.15	0.00	0.00	32.84
Total	315,779	1,897,000.0	71.2	148.20	133.25	281.45	12.72	(2.88)	4.37	1.09	0.00	0.00	296.75

Proposed Rates

Month	GTR Customers	GTR Normalized Mcf	Usage Per Customer Mcf/Cus	Customer Charge Revenue	Volumetric Delivery Charge Revenue @ $2.4322/Mcf	Total Delivery Charge Revenue	AMRP Revenue $0.00/Bill	EECP Charge Revenue $(.24)/Bill	Volumetric EAP Charge Revenue @ $0.0615/Mcf	Volumetric R&D Charge Revenue @ $0.015/Mcf	Volumetric GCA Charge Revenue @ $0.0000/Mcf	Volumetric Uncollectible Charge Revenue @ $0.0000/Mcf	Total Bill
(1)	(2)	(3)	(4=3/2)	(5)	(6)	(7=5+6)	(8)	(9)	(10)	(11)	(12)	(13)	(14 = 7 thru 13)
				($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
Jan	26,761	410,000.0	15.3	18.50	37.21	55.71	0.00	(0.24)	0.94	0.23	0.00	0.00	56.64
Feb	26,804	389,000.0	14.5	18.50	35.27	53.77	0.00	(0.24)	0.89	0.22	0.00	0.00	54.64
Mar	26,750	295,000.0	11.0	18.50	26.75	45.25	0.00	(0.24)	0.68	0.17	0.00	0.00	45.86
Apr	26,572	181,000.0	6.8	18.50	16.54	35.04	0.00	(0.24)	0.42	0.10	0.00	0.00	35.32
May	26,351	77,000.0	2.9	18.50	7.05	25.55	0.00	(0.24)	0.18	0.04	0.00	0.00	25.53
Jun	26,140	39,000.0	1.5	18.50	3.65	22.15	0.00	(0.24)	0.09	0.02	0.00	0.00	22.02
Jul	25,964	27,000.0	1.0	18.50	2.43	20.93	0.00	(0.24)	0.06	0.02	0.00	0.00	20.77
Aug	25,891	26,000.0	1.0	18.50	2.43	20.93	0.00	(0.24)	0.06	0.02	0.00	0.00	20.77
Sep	25,869	27,000.0	1.0	18.50	2.43	20.93	0.00	(0.24)	0.06	0.02	0.00	0.00	20.77
Oct	25,960	44,000.0	1.7	18.50	4.13	22.63	0.00	(0.24)	0.10	0.03	0.00	0.00	22.52
Nov	26,236	115,000.0	4.4	18.50	10.70	29.20	0.00	(0.24)	0.27	0.07	0.00	0.00	29.30
Dec	26,481	267,000.0	10.1	18.50	24.57	43.07	0.00	(0.24)	0.62	0.15	0.00	0.00	43.60
Total	315,779	1,897,000.0	71.2	222.00	173.16	395.16	0.00	(2.88)	4.37	1.09	0.00	0.00	397.74

John J. Spanos

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of)
Columbia Gas of Kentucky, Inc.) Case No. 2013-00167

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

Stephen B. Seiple, Asst. General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF JOHN J. SPANOS

Q: Please state your name and business address.

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

Q: Are you associated with any firm?

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

Q: How long have you been associated with Gannett Fleming, Inc.?

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

Q: What is your position with the firm?

A: I am the Senior Vice President of the Valuation and Rate Division.

Q: What is your educational background?

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

Q: Do you belong to any professional societies?

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

Q: Do you hold any special certification as a depreciation expert?

A: Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q: Please outline your experience in the field of depreciation.

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

I helped perform depreciation studies for the following organizations in the electric industry: Chugach Electric Association, The Cincinnati Gas and Electric Company ("CG&E"), The Union Light, Heat and Power Company ("ULH&P"), Northwest Territories Power Corporation and the City of Calgary - Electric System.

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

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

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

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

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December, 2000, I was promoted to the position of Vice-President of the Valuation and Rate Division of Gannett Fleming, Inc. In April 2012, I was promoted to my current position as Senior Vice President and I became responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

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

Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana, Entergy Gulf States Louisiana, the Borough of Hanover, Madison Gas and Electric, Atlantic City Electric and Greater Missouri Operations. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q: Have you submitted testimony to any regulatory utility commissions on the subject of utility plant depreciation?

A: Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission; the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Utah Public Service Commission; Wyoming Public Service Commission; and the North Carolina Utilities Commission.

Q: Have you had any additional education relating to utility plant depreciation?

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

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

A: I sponsor the depreciation study performed for Columbia Gas of Kentucky, Inc. ("Columbia" or "the Company").

Q: Please define the concept of depreciation.

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

Q: Was your depreciation study included as part of the Application filed in this case?

A: Yes, it is included as a report entitled, "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2012" per Filing Requirement 12-S. This report sets forth the results of my depreciation study for Columbia.

Q: Are you familiar with the contents of the depreciation study filed as part of the Application in this case?

A: Yes.

Q: Is the study a true and accurate copy of your depreciation study?

A: Yes.

Q: Was the depreciation study prepared under your direction and control?

A: Yes.

Q: Does the study accurately portray the results of your depreciation study as of December 31, 2012?

A: Yes.

Q: In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation valuation?

A: Yes.

Q: Please describe the contents of your report.

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

The table on pages III-4 and III-5 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2012, the book reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page III-6 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-92 presents the results of the salvage analysis. The section beginning on page III-137 presents the depreciation calculations related to surviving original cost as of December 31, 2012.

Q: Please explain how you performed your depreciation study.

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

For General Plant Accounts 391.1, 391.11, 391.12, 394.0, 395.0 and 398.0, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2012. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q: How did you determine the recommended annual depreciation accrual rates?

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

Q: Please describe the first phase of the depreciation study, in which you estimated the service life and net salvage characteristics for each depreciable group.

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

Q: What historical data did you analyze for the purpose of estimating service life characteristics?

A: I analyzed Columbia's accounting entries that record plant transactions during the period 1939 through 2012. The transactions included additions, retirements, transfers, sales and the related balances. Columbia's records included surviving dollar value by year installed for each plant account as of December 31, 2012.

Q: What method did you use to analyze this service life data?

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

Q: Please describe how you used the retirement rate method to analyze Columbia's service life data.

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

Q: What is an "Iowa-type Survivor Curve" and how did you use such curves to estimate the service life characteristics for each property group?

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

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

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 39-R1.5 indicates an average service life of thirty-nine years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q: **Have you physically observed Columbia's plant and equipment in the field as part of your depreciation assignments?**

A: Yes. I have made field reviews of Columbia's property on March 18 and 19, 2002, October 28, 2008 and February 5, 2013, to observe representative portions of plant and it was determined an additional trip for this study was not necessary. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q: **How did you estimate net salvage percentages?**

A: I estimated the net salvage percentages by incorporating the historical data for the period 1969 through 2012 and considered estimates for other gas companies.

Q: **Please describe the second phase of the process that you used in the depreciation study in which you calculated composite remaining lives and annual depreciation accrual rates.**

A: After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the equal life group procedure.

Q: **Please describe the straight line remaining life method of depreciation.**

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

Q: What are the most commonly utilized depreciation procedures?

A: The average service life and equal life group procedures are the most widely utilized depreciation procedures used by utility companies across the United States and Canada. Each procedure is briefly described on page II-29 of the Depreciation Study. The procedures represent straight line depreciation and meet the requirement of systematic and rational recovery.

Q: Have you reviewed the results of both procedures?

A: Yes. I have conducted depreciation calculations using both the average service life and equal life group procedures. The average service life procedure is most commonly utilized in Kentucky as it balances full recovery based on the average life which establishes a smoother recovery pattern as compared to the more precise equal life group procedure.

Q: Please describe the equal life group procedure.

A: The equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals. This procedure is the most accurate for matching recovery of the asset to consumption or utilization of the asset.

Q: Please describe amortization accounting.

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

Q: **Amortization accounting is being implemented to which plant accounts?**

A: Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.1, 391.11, 391.12, 394.0, 395.0 and 398.0 which represent slightly more than one percent of depreciable plant.

Q: **Please use an example to illustrate how the annual depreciation accrual rate for a particular group of property is presented in your depreciation study.**

A: I will use Account 376, Mains, as an example because it is the largest depreciable group and represents 51% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1939 through 2012 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1939-2012 and 1973-2012 experience bands are presented on pages III-32 through III-37 of the report. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page III-32 shows $108,848 retired at age 0.5 with $157,844,891 exposed to retirement. Consequently, the retirement ratio is .0007 and the surviving ratio is 0.9993. These life tables, or original survivor curve, are plotted along with the estimated smooth survivor curve, the 70-R1.5 on page III-31.

The net salvage percent is presented on pages III-101 through III-103. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1969 through 2012. The 44-year period experienced $1,891,507 (($3,767) – $1,887,740) in net salvage for $14,553,734 plant retired. The result is negative net salvage of 13 percent ($1,891,507/$14,553,734). The most recent five-year average is negative 15 percent. Therefore, it was determined that based on industry ranges and

Columbia's expectations, that negative 15 percent was the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2012, of utility plant is presented on pages III-148 through III-153. The calculation is based on the 70-R1.5 survivor curve, 15% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page III-4.

Q: Was there separate life and net salvage analysis performed for the subaccounts of Account 376, Mains?

A: No, there was not. The historical data did not maintain a type pipe identifier, but historical balances were available by type pipe, therefore, separate life characteristics could not be accurately studied. Thus, one common service life and net salvage estimate for all mains. The common survivor curve and net salvage percent was applied to the surviving balance as of December 31, 2012 by subaccount.

Q: Explain what was different at the subaccount level.

A: A main replacement program has been established for bare steel and cast iron mains. The program is a 30-year program, starting at the beginning of 2008, and at the end of the 30 years all bare steel and cast iron pipe will have been replaced. Therefore, the depreciation rates must be established to match capital recovery to life expectancy. In order to accomplish the appropriate matching principle, the surviving bare steel and cast iron investment must be recovered by year-end 2037. Consequently, the annual depreciation rate for bare steel and cast iron in Account 376 has a truncation date of December 2037. This is consistent with the current practices and depreciation rates.

Q: Does this complete your Prepared Direct testimony?

A: Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates	)	Case No. 2013-00167
of Columbia Gas of Kentucky, Inc.	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, John J. Spanos, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

John J. Spanos

John J. Spanos

COMMONWEALTH OF PENNSYLVANIA

COUNTY OF CUMBERLAND

SUBSCRIBED AND SWORN to before me by John J. Spanos on this the 22nd day of May, 2013.

Notary Public

My Commission expires: February 20, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Susanne M. Taylor

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of)
Columbia Gas of Kentucky, Inc.) Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF
SUSANNE M. TAYLOR
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

<u>PREPARED DIRECT TESTIMONY OF SUSANNE M. TAYLOR</u>

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

A: My name is Susanne M. Taylor. My business address is 200 Civic Center Drive, Columbus, Ohio 43215.

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

A: I am employed by NiSource Corporate Services Company ("NCSC") as Controller. As Controller, my principal responsibilities include overseeing the general books and records of NCSC. In carrying out these duties, I am responsible for a number of activities, including:

(1) Overseeing the accounting system that identifies the costs for services that are subsequently billed to the operating companies within the NiSource Inc. ("NiSource") corporate organization ("NiSource affiliates" or "affiliates"); and,

(2) Certifying accounting data, providing testimony, and responding to requests from regulatory and legislative bodies with regard to NCSC billing on behalf of NiSource affiliates.

Q: **What is your educational background?**

A: I received a Bachelor of Science degree in Accounting in 1991 from Ohio University, Athens, Ohio.

Q: **What are your professional credentials?**

A: I am a Certified Public Accountant and am currently a member of the Ohio Society of Certified Public Accountants ("OSCPA") and American Institute of CPA's ("AICPA"). I regularly attend accounting and accounting-related seminars sponsored by various organizations including the American Gas Association, OSCPA, Corporate Executive Board and Deloitte & Touche.

Q: **Please describe your employment history?**

A: I was employed at KPMG Peat Marwick from August 1991 through June 1993 where I held various accounting positions ranging from Staff Accountant to In-Charge Accountant. In July 1993, I was hired by the Columbia Energy Group's Service Corporation as a Staff Auditor. From May 1994 to May 2000, I held various analyst positions in the Regulatory Department. In June 2000, I took a position as Lead Financial Analyst in the Financial Planning Support Department. Subsequent to the merger between Columbia Energy Group and NiSource Inc., I was promoted to

Manager of Corporate Accounting on November 1, 2000, and then to Controller of NCSC in April 2005.

Q: **Have you previously testified before any regulatory Commission?**

A: Yes, I have testified before the Indiana Utility Regulatory Commission, the Commonwealth of Virginia State Corporation Commission, the Pennsylvania Public Utility Commission, the Kentucky Public Service Commission and the Federal Energy Regulatory Commission.

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

A: The purpose of my testimony is to provide background about NCSC and the role it serves within NiSource. I also provide information pertaining to the types of costs that have been allocated to Columbia Gas of Kentucky, Inc. ("Columbia") and the mechanism for determining the appropriate allocation of each type of cost. Additionally, I sponsor Filing Requirement 12-u.

I. THE RELATIONSHIP BETWEEN NCSC AND COLUMBIA

Q: **What is the structure and role of NCSC?**

A: NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource corporate organization. NCSC provides a range of services to the individual operating companies within NiSource, including Columbia, and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors.

Q: **As Controller, do you oversee the allocation and billing of affiliate charges by NCSC?**

A: Yes, my area is responsible for reviewing general overall charges billed to each of the NiSource affiliates by NCSC. I am also responsible for the accounting system that tracks and identifies the costs for services that are subsequently billed to NiSource affiliates, including Columbia.

Q: **Please identify the individual corporate affiliates for which NCSC performs services.**

A: Please refer to Attachment SMT-1, which lists all affiliates for whom NCSC provided services during the test period.

Q: **How are costs billed to affiliates?**

A: There are two types of billings made to affiliates, including Columbia: 1) contract billing; and 2) convenience billing. Contract billings are identified by job order and represent NCSC labor and expenses billed to the respective affiliate. Contract billed charges may be direct (billed directly to a single affiliate or affiliates) or allocated (split between or among several affiliates), depending on the nature of the expense.

Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services. Therefore, NCSC makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliates.

Q: **Is contract billing rendered pursuant to an executed contract?**

A: Yes, NCSC has executed an individual Service Agreement with each affiliate, which designates the type of services to be performed and the method of calculating the charges for these services. Services rendered under the Service Agreement are provided at cost, including charges for interest. The Service Agreement is updated as needed so that all affiliates that receive service from NCSC are subject to the same modifications, with one exception.[1] A copy of the most recent Service Agreement between NCSC and Columbia was filed with the Commission and approved by Order dated January 1, 2007. A copy of the 2007 Agreement is attached hereto as Attachment SMT-2.

Q: **What are the services provided by NCSC?**

A: As detailed in Appendix A, Article 2 of the Service Agreement, the services provided by NCSC to Columbia are Accounting and Statistical Services; Auditing Services; Budget Services; Business Promotion Services; Corporate Services; Employee Services; Engineering and Research Services; Gas Dispatching Services; Information Technology Services; Information Services; Insurance Services; Legal Services; Office Space; Operations Support and Planning Services; Purchasing, Storage and Disposition Services; Rate Services; Tax Services; Transportation Services;

[1] The Virginia State Corporate Commission required inclusion of a Virginia-specific service category that is not included in the Service Agreements for non-Virginia affiliates.

Treasury Services; Land/Surveying Services; Customer Billing, Collection, and Contract Services; and Miscellaneous Services.

II. COST ASSIGNMENT TO COLUMBIA BY NCSC

Q: How does NCSC determine charges applicable to Columbia?

A: In compliance with PUHCA 2005 and FERC, NCSC uses a job order system to collect costs that are applicable and billable to affiliates, including Columbia.[2] A job order assigns a 10-digit number to the project(s) involved and details how expenses are to be charged for the project(s). This is the same job order system that has been used by NCSC for many years. Specific projects undertaken by an affiliate are assigned by that affiliate to an existing job order or a new job order is created. Costs are directly charged to a particular affiliate whenever possible. Some job orders necessarily involve more than one affiliate, and in that case, the job order details how expenses are allocated among participating affiliates.

---

[2] NCSC was regulated by the SEC under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to FERC. Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis of allocation.

Q: **How are costs assigned to a particular job order allocated?**

A: Allocations among affiliates are made only if it is impractical or inappropriate to charge an affiliate directly. Whenever a new job order is required, NCSC Accounting works cooperatively with department sponsors or project leaders through meetings and discussions to build consensus on how the job order will be allocated to NiSource affiliates. During these meetings, there are detailed discussions on how to determine what costs are to be assigned to the job order, the cost allocation basis that should be used, which companies will benefit from the service provided, and the portion of the cost each affiliate should receive and record in its accounting records. Once NiSource management agrees to the basics of the potentially created job order, a job order request form is submitted by the department sponsor or project leader and reviewed and approved by NCSC Accounting management. Costs are then assigned by NCSC Accounting personnel using the corresponding base allocation or direct company billing code.

Q: **What controls are in place to ensure that an affiliate is consistently and appropriately billed for a specific job order?**

A: The job orders are maintained by the NCSC Accounting Department and, therefore, only designated individuals within NCSC Accounting can create or modify job orders. A creation or modification of a job order must be approved by NCSC Accounting management. Each job order can be set up with only one Basis of Allocation, and in many cases, only one specific allocation code or direct company billing is set up for a particular job order, depending on what affiliate(s) benefit from the services. If an individual would attempt to use a different Basis of Allocation with a job order that was not selected at inception, the related accounting systems would prompt an immediate error upon data entry and not allow the job order to be input.

Q: **Has the FERC conducted an audit of NCSC, its billing system and allocation methodologies?**

A: Yes. NiSource Inc., including NCSC, underwent a FERC audit, Docket No. FA11-5-000, which covered the period January 1, 2009, through December 31, 2010. The Final Audit Report was issued by the FERC on October 24, 2012. As indicated in the Final Report, the Audit Staff reviewed and tested the supporting details for NCSC's cost allocation methods. They then sampled and selected supporting documents to ensure that NCSC's billings and accounting comply within the USOA (Uniform System of Accounts). FERC did not issue any adverse comments to NCSC related to its allocation methods.

Q: **What are the Bases of Allocation?**

A: NCSC allocates costs for a particular job order in accordance with the following Bases of Allocation that have been previously approved by the SEC and filed annually with the FERC:

<u>BASIS 1</u> - Gross Fixed Assets and Total Operating Expenses

<u>BASIS 2</u> - Gross Fixed Assets

<u>BASIS 3</u> - Number of Meters Serviced

<u>BASIS 4</u> - Number of Accounts Payable Invoices Processed[3]

<u>BASIS 7</u> - Gross Depreciable Property & Total Operating Expenses

<u>BASIS 8</u> - Gross Depreciable Property

<u>BASIS 9</u> - Automotive Units

[3] Recently added Allocation Basis 3 and 4, with effective date of January 1, 2013, were not filed with or approved by the FERC. However, an official approval by the FERC is not required per Article 2.2 of the NCSC Service Agreement. The addition of Allocation Basis 3 and 4 was approved by the segment Chief Financial Officers, along with the Business Unit Presidents. Columbia notified the Kentucky PSC of the additional bases as part of its Annual Report Relating to Nonregulated Activity of an Affiliated Utility or its Affiliates which was filed on April 1, 2013.

BASIS 10 - Number of Retail Customers

BASIS 11 - Number of Regular Employees

BASIS 13 - Fixed Allocation (Information Technology and Legal fixed allocations)

BASIS 14 - Number of Transportation Customers

BASIS 15 - Number of Commercial Customers

BASIS 16 - Number of Residential Customers

BASIS 17 - Number of High Pressure Customers

BASIS 20 - Service Company Billing (Direct and Allocated) Costs

A description of each Basis of Allocation is included in Filing Requirement 12-u.

Q: **Please explain each affiliate's rights regarding bills issued by NCSC?**

A: In accordance with the 2007 Service Agreement (Section 2.3), affiliates have the right to review and challenge any particular item for which they are billed.

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

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Susanne M. Taylor, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Susanne M. Taylor

Susanne M. Taylor

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by Susanne M. Taylor on this the 22 day of May, 2013.

NOTARIAL SEAL STATE OF OHIO

Mary Traetow
Notary Public, State of Ohio
My Commission Expires 10-27-2014

Mary Traetow

Notary Public

My Commission expires: 10-27-2014

ATTACHMENT SMT-1

NiSource Corporate Services Company

List of Associate Billing Companies

Company Name	Billing Company No.
Columbia Energy Group	11
Columbia Gulf Transmission Company	14
NiSource Insurance Corporation Limited	22
Energy USA-TPC Corp.	24
Columbia Gas of Kentucky, Inc.	32
Columbia Gas of Ohio, Inc.	34
Columbia Gas of Maryland, Inc.	35
Columbia Gas of Pennsylvania, Inc.	37
Columbia Gas of Virginia, Inc.	38
Crossroads Pipeline Company	44
Columbia Gas Transmission Corporation	51
Columbia Remainder Corporation	54
CNS Microwave, Inc.	57
NiSource Inc.	58
Northern Indiana Public Service Company	59
NiSource Development Company, Inc.	60
NiSource Capital Markets, Inc.	62
Energy USA, Inc. (IN)	68
NiSource Retail Services, Inc.	71
NiSource Finance Corp.	75
NiSource Energy Technology, Inc.	78
Columbia Gas of Massachusetts, Inc.	80
NiSource Gas Transmission and Storage Company	82
NiSource Energy Ventures, LLC	92
Columbia of Ohio Receivables Corporation	93
Columbia Gas of Pennsylvania Receivables Corporation	94
NIPSCO Accounts Receivables Corporation	95
NiSource Midstream Services, LLC	96
Kennesaw Pipeline, LLC	97

ATTACHMENT SMT-2

Service Agreement

BETWEEN

NISOURCE CORPORATE SERVICES COMPANY

AND

COLUMBIA GAS OF KENTUCKY, INC.

Dated January 1, 2007

(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into this __________, 2007 by and between Columbia Gas of Kentucky, Inc., its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, the Securities and Exchange Commission ("SEC") has approved and authorized as meeting the requirements of Section 13(b) of the Public Utility Holding Company Act of 1935 ("Act") the organization and conduct of the business of the Company, in accordance herewith, as a wholly-owned subsidiary service company of NiSource Inc. ("NiSource), including the allocation of all Company costs by using the methods approved by the Securities and Exchange Commission ("SEC Method");

WHEREAS, Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at cost, with cost determined in accordance with applicable rules and regulations under the Act, which require the Company to fairly and equitably allocate costs among all Clients to which it renders services; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with the SEC Method. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably allocated, all in accordance with the requirements of the Act and any orders promulgated thereunder. The Company shall review with the Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall render a monthly report to Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake an immediate review of the report and identify all questions or concerns regarding the charges reflected within ten (10) days of receipt of the report. If no concerns are identified within that time, Client shall remit to the Company all charges billed to it within 30 days of receipt of the monthly report.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and the SEC, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the SEC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 On an annual basis, the Company and Client shall meet to assess the quality of the Services being provided pursuant to this Service Agreement and to determine the continued need therefor and shall, subject to Section 1.1, above, amend the scope of services, delete services entirely from this Service Agreement, and/or decline services as they determine to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the General Rules and Regulations promulgated by the SEC pursuant to the Act, in particular, the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies in effect from and after the date hereof.

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

NISOURCE CORPORATE SERVICES
COMPANY

By: ______________________________
Name:
Its:

COLUMBIA GAS OF KENTUCKY, INC.

By: ______________________________
Name:
Its:

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

1 The term "Company" shall mean NiSource Corporate Services Company and its successors.

2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.

3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company will advise and assist the Clients in all aspects of accounting, including financial accounting, plant accounting, regulatory accounting, tax accounting, maintenance of books and records, safeguarding of assets, accounts payable, accounts receivable, reconciliations, accounting research, reporting, operations and maintenance analysis, and related accounting functions. The Company will also provide services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company will ensure compliance with generally accepted accounting principles and provide guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company will advise and assist the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants in the annual examination of their accounts.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of budgets and budgetary controls.

4 *Business Promotion Services.* The Company will advise and assist the Clients in the preparation and use of advertising, in the development of residential, commercial and industrial business, and in the rendering of aid to local appliance distributors and dealers in the advertising and promotion of appliance sales.

5 *Corporate Services.* The Company will advise and assist the Clients in connection with corporate matters and with proceedings involving regulatory bodies.

6 *Depreciation Services.* The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

7 *Economic Services.* The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

8 *Electronic Communications Services.* The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

9 *Employee Services.* The Company will advise and assist the Clients in connection with employee relations matters, including recruitment, employee placement, training, compensation, safety, labor relations and health, welfare and employee benefits. The Company will also advise and assist the Clients in connection with temporary labor matters, including assessment, selection, contract negotiation, administration, service provider relationships, compliance, review and reporting.

10 *Engineering and Research Services.* The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, engineering and supervision of the fabrication of natural gas facilities, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

11 *Gas Dispatching Services.* The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

12 *Information Technology Services.* The Company will advise and assist Clients in matters involving information technology, including management, operations, control, monitoring, testing, evaluation, data access security, disaster recovery planning, technical research, and support services. The Company will also provide and assist the Client with application development, maintenance, modifications, upgrades and ongoing production support for a portfolio of systems and software that are used by the Clients. In addition, the Company will identify and resolve problems, ensure efficient use of software and hardware, and ensure that timely upgrades are made to meet the demands of the Clients. The Company will also maintain information concerning the disposition and location of Information Technology assets.

13 *Information Services.* The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

14 *Insurance Services.* The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

15 *Legal Services.* The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice (relating to the all aspects of SEC compliance, PUHCA, FERC, FPA, PURPA), bankruptcy and collection matters, employment and labor relations investigations, union contracting, EEOC issues, and all other matters for which Clients require such legal services.

16 *Office Space.* As may from time to time be available, the Company will provide suitable space in its offices for the use of the Clients and their officers and employees.

17 *Officers.* Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

18 *Operations Support and Planning Services.* The Company will advise and assist the Clients in connection with operations support and planning, including logistics and scheduling; workforce planning; corrosion and leakage programs; estimates of gas requirements and gas availability; gas transmission, measurement, storage and distribution; construction requirements; construction management; operating standards and practices; regulatory compliance; training; management of transportation and sales programs; negotiation of gas purchase and sale contracts; energy marketing and trading; security services; measurement, regulation and conditioning equipment; meter testing, calibration and repair; hydraulic gas network modeling, facility mapping and GIS technologies; and other operating matters.

19 *Purchasing, Storage and Disposition Services.* The Company will render advice and assistance to the Clients in connection with supply chain activities, including the standardization, purchase, lease, license and acquisition of equipment, materials, supplies, services, software, intellectual property and other assets, as well as shipping, storage and disposition of same. The Company will also render advice and assistance to the Client in connection with the negotiation of the purchase, sale, acquisition or disposition of assets and services and the placing of purchase orders for the account of the Client.

20 *Rate Services.* The Company will advise and assist the Clients in all rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings of producers and pipeline suppliers, and the preparation and presentation of testimony and exhibits to regulatory authorities.

21 *Tax Services.* The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

22 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

23 *Treasury Services.* The Company provides services such as cash management, long and short term financing for NiSource and all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, special economic studies as requested, and support for various regulatory proceedings, as requested.

24 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

25 *Customer Billing, Collection, and Contact Services.* The Company will render calculating, bill exception processing, back office processing, posting, printing, inserting, mailing and related services to Client associated with the preparation and issuance of customer bills, notices, inserts and similar mailings. The Company will provide cash processing, revenue recovery, account reconciliations and adjustments, and related services to Client associated with the collection of revenue and management of accounts receivable. The Company will provide customer contact and related services to Client, including customer contact center management, operation and administration; management of key customer relationships; communications associated with the commencement, transfer, maintenance and disconnection of service; sales of optional products and services; the receipt and processing of emergency calls; the handling of customer complaints; and responses to customer billing, credit, collection, order take and inquiry, outage, meter reading, retail choice and other inquiries.

26 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, as may properly be rendered by the Company to such Client

within the meaning and intent of the Public Utility Holding Company Act of 1935 and any other applicable statutes and the orders, rules and regulations of the Securities and Exchange Commission and any other governmental bodies having jurisdiction, as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method approved by the Securities and Exchange Commission as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses which are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall be apportioned among the Clients, as applicable, in the proportions which the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

BASES OF ALLOCATION

The SEC approved Bases of Allocation shown below will be used by the Corporate Services Accounting Department for apportioning Job Order charges to affiliates. Any change in an allocation method that causes either a $50,000 or 5% change in the cost that would be charged to a company must be brought to the SEC for approval under the 60-Day Letter process.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Job order charges will be allocated to each benefited affiliate on the basis of the relationship of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Job order charges will be allocated to each benefited affiliate on the basis of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Job order charges will be allocated to each benefitted affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 20

DIRECT COSTS

- Job order charges will be allocated to each benefitted affiliate on the basis of the relation of its direct costs billed by Service Corporation to the total of all direct costs billed by Service Corporation. All companies may be included in this allocation.

Columbia Exhibit No.________

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of	)	
Columbia Gas of Kentucky, Inc.	)	Case No. 2013-00167

PREPARED DIRECT TESTIMONY OF PANPILAS W. FISCHER ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Stephen B. Seiple, Assistant General Counsel
Brooke E. Leslie, Senior Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

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

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 29, 2013

PREPARED DIRECT TESTIMONY OF PANPILAS W. FISCHER

Q: Please state your name and business address.

A: My name is Panpilas W. Fischer and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

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

A: I am employed by NiSource Corporate Services Company, and my current position is the Manager of Corporate Income Tax. As Tax Manager, my principal responsibilities include supervision and preparation of all of Columbia Gas of Kentucky's ("Columbia") income tax activities including the booking of income tax accruals and deferred tax entries, the filing of income tax returns, tax research and planning and the preparation of income tax data and related testimony for rate proceedings.

Q: What is your educational background?

A: I received a Bachelor of Business Administration in Accounting from The Ohio State University in 1987. I am a Certified Public Accountant and member of the Ohio Society of Certified Public Accountants.

Q: Please describe your employment history?

A: I began my career with KPMG as a Staff Auditor in 1987. I then joined the firm of Clark, Schaefer, Hackett and Co., CPA's as a Senior in 1989 where I performed financial audits, reviews and compilations, and prepared and reviewed tax returns. In October 2000, I started working as a tax analyst for NiSource Corporate Services Company and in October 2003, I assumed my current position.

Q. Have you previously testified before any regulatory commissions?

A: Yes, I have previously testified before the Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Public Service Commission of Maryland, and the Pennsylvania Public Utility Commission.

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

A: My testimony will address the calculation of the proper level of federal and state income taxes included in the cost of service. This calculation includes the appropriate level of statutory tax adjustments for this proceeding, including depreciation, and the determination of deferred income taxes for rate purposes.

Q: What schedules are you responsible for in this proceeding?

A: I am responsible for Schedules E-1 and B-6. I co-sponsor Filing Requirements 11-a and 11-b. These schedules and the supporting work papers were prepared by me or under my direction, and the information set forth is true and correct, to the best of my knowledge and belief.

Q: What federal income tax rates have been utilized for the test period?

A: The Internal Revenue Code ("IRC") provides for a tax rate of 34% for corporations with taxable income up to $10 million. The rate increases to 35% for taxable income over $10 million. Beginning at $15 million of taxable income the rate is 38% until taxable income reaches $18.33 million. All taxable income over $18.33 million is taxed at the 35% rate. The effect of the 38% rate is to phase out the 1% savings at the 34% rate for the first $10 million of taxable income. Effectively, the tax rate is 35% for corporations with taxable income over $18.33 million for all taxable income.

Q: What rate was utilized for Kentucky income taxes?

A: The rates utilized are the statutory tax rates based on taxable income and tax liability as follows:

4% of the first $50,000 of taxable income

5% of the next $50,000 of taxable income

6% of the taxable income in excess of $100,000.

Q: Please explain the income tax calculation shown on Schedule E-1.

A: This schedule shows the computation of federal income taxes for the base period ending August 31, 2013, including the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the customer cost of service for the calculation of income tax expense. The tax calculation begins with net operating income before income taxes (Line 1). This amount is adjusted by interest, reconciling items detailed on Sheet 2 of Schedule E-1 and state income tax. The items on Sheet 2 reflect the difference between income and expenses as properly reflected on the regulated books of the company, and income and expenses as required/allowed for reporting taxable income based on the IRC. These adjustments are commonly referred to as "Schedule M" adjustments in reference to their reporting position on the federal income tax return (Form 1120). The tax return differences can be mere timing differences between book and tax return reporting or can be permanent differences in taxable income. Normally, the tax expense effects of permanent differences are recorded currently (flowed through) while timing differences are deferred (normalized) on the books until the timing differences are eliminated. Regulatory orders may, in certain instances, change the normal accounting for permanent and timing tax adjustments.

The next step in the calculation is to apply the appropriate federal tax rates to the taxable income for return purposes (Line 9) to arrive at current year federal income taxes payable (Line 11).

Line 12 represents federal income tax expense items recorded in 2012 related to prior year taxes. The direct adjustment related to the books to return reconciliation for the year 2011 total $(132,167). The books to return adjustments represent the difference between what was recorded at December 31, 2011 for current tax expense and the actual taxes per the filed tax. This item has been pro forma adjusted to reflect a zero impact on 2012. Line 14 represents the net current federal income taxes.

Q: Please explain the income tax schedule shown on Schedule E-1, Sheet 2.

A: The schedule reflects estimated timing and flow through differences between the regulatory books and what will be allowed on the tax returns filed in 2012 and 2013.

Q: Does the state income tax provision include a pass back of excess deferred income taxes as a result of reductions in the Kentucky state income tax rate?

A: Yes. Included in Line 20 is an adjustment for the annual amortization. This benefit will occur over the remaining book life of the property in service at the time Kentucky state income tax rates were lowered. (The total amount of Columbia's regulatory liability, including a tax gross up at the end of the base period, is $1,120,627. This includes any prior year flow through as an asset.)

Q: Are there any federal excess or deficient taxes included in rates?

A: Yes. Columbia has a regulatory liability for federal excess, including gross up, of $573,012. The amortization is included in Line 17.

Q: Are there any changes in taxes that are impacting Columbia's rate base?

A: Yes. Included in deferred income taxes as a reduction to rate base in Schedule B-6, Sheet 1 is an adjustment for the tax repairs deduction and Section 263A mixed service costs ("MSC"). NiSource received permission from the Internal Revenue Service ("IRS") in August, 2009 to change its definition of "unit of property" so that certain expenditures can be deducted for tax purposes as a repairs deduction rather than being capitalized and reflected as a decrease in rate base as part of sub account 2205 and 4205 is a deferred tax liability of approximately $15.5 million for tax repairs deductions which represents the 13 month average balance in the forecasted test period.

In December, 2010, Columbia received permission from the IRS to change its method of allocating mixed service costs for tax purposes. MSC's are general and administrative costs that are indirectly allocable (i.e. not exclusively attributable) to activities related to self-constructed assets and inventory property and must be partially capitalized rather than fully deducted for book and tax purposes. The allocation methods differ for book and tax purposes. For tax purposes the reasonable allocation method is being used which is adopted pursuant to Internal Revenue Service Industry Director's Directive (IDD) 5 issued September 15, 2009 which provides guidelines on the method transmission and distribution companies can use to allocate MSC for tax purposes. Reflected as a decrease in rate base as part of sub account 2205 and 4205, is a deferred tax liability of approximately $3.9 million for MSC deductions which represents the 13 month average balance in the forecasted test period. Columbia is normalizing these deductions for federal and state income taxes which result in a different book vs. tax basis on property. This treatment is consistent with how other book vs. tax timing differences on property related items are handled in rate base.

Q: **Please explain the inclusion of deferred taxes for the Federal Net Operating Loss in rate base on Schedule B-6, Sheet 1.**

A: As a result of taking deductions for 50-100% bonus depreciation, Columbia has experienced net taxable losses for the years 2008 and 2011. The result is that Columbia booked deferral taxes in those years for which the Company has not received any cash. Columbia cannot reflect an increase in deferred taxes for tax depreciation deductions that have not been realized. To do so would violate the principles of the Normalization requirements under the Internal Revenue Code. Past IRS rulings addressing this issue have made it clear that companies cannot reduce rate base for benefits that have not been realized. Therefore, included as an increase to rate base is a deferred tax asset in the amount of $1,222,674, which represents the 13 month average balance of un-utilized net operating loss in the forecasted test period.

Q: Why have you included an adjustment to deferred taxes for the forecasted test period on Schedule B-6, Sheet 1?

A: Whenever there are estimated changes in the deferred taxes that occur in a future rate period, the Normalization requirements of the Internal Revenue Code require that the deferred taxes be reflected on a pro rata basis as provided under Reg. Section 1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test period after the effective date of the rate order. Under the pro rata basis, the change in the deferred taxes is determined by multiplying the change by a fraction of the number of days remaining in the period at the time such change is to be accrued over the total number of days in the future period. Applying this calculation resulted in a decrease to deferred taxes of $451,155.

Q: Does this complete your Prepared Direct testimony?

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATE AND AFFIDAVIT

The Affiant, Panpilas Fischer, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2013-00167, in the matter of adjustment of rates of Columbia Gas of Kentucky, Inc., and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Panpilas Fischer

STATE OF OHIO

COUNTY OF FRANKLIN

SUBSCRIBED AND SWORN to before me by Panpilas Fischer on this the ____ day of May, 2013.

NOTARIAL SEAL
STATE OF OHIO

CHERYL A. MacDONALD
Notary Public, State of Ohio
My Commission Expires
March 26, 2017

Notary Public

My Commission expires: MARCH 26, 2017