COMMONWEALTH OF KENTUCKY

OFFICE OF THE ATTORNEY GENERAL

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11 September 2013

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

RE: *In the Matter of*: Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service, Case No. 2013-00167

Dear Mr. Derouen:

Please find enclosed for filing the Attorney General's pre-filed written Direct Testimony in the above-styled matter. In accordance with the Commission's rules of procedure, 807 KAR 5:001 Section 13, this is to advise the Commission that the Attorney General's testimony filed herewith includes a separate sealed envelope marked as CONFIDENTIAL, containing an unredacted, CONFIDENTIAL version of the Direct Testimony of Mr. Watkins, which identifies or otherwise references items of information pertaining to special contracts for which the petitioner, Columbia Gas of Kentucky/NiSource, has sought confidential protection in its petitions filed on 19 June 2013, 2 August 2013, and the 28 August 2013, respectively. As of the date of this filing, the petitions seeking confidentiality are pending before the Commission.

The Attorney General has entered into a non-disclosure agreement with the applicant, agreeing to protect the confidentiality of information for which Columbia Gas of Kentucky/NiSource deems confidential, and for which it seeks confidential protection from the Public Service Commission by the petition. The Attorney General's filing herewith is consistent with that agreement.

Please advise if you should have any questions, or require any further information concerning this filing.

Yours truly,

Dennis G. Howard, II
Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF RATES OF	**)**	**Case No. 2013-00167**
COLUMBIA GAS OF KENTUCKY, INC.	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

FRANK W. RADIGAN

ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY

September 11, 2013

Columbia Gas of Kentucky
Case No. 2013-00167
Direct Testimony and Exhibits of
Frank W. Radigan

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I – INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I have been engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Columbia Gas of Kentucky ("CKY or "the Company") for an increase in its base rates for gas service.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission (PSC) in the Rates and System Planning sections of the Power Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State, which encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the Commission, I was responsible for Directing all engineering staff during major proceedings including those relating to rates, integrated resource planning and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company.

In my 32 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies including the Arizona Corporation Commission, the Connecticut Public Regulatory Authority, the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the Federal Energy Regulatory Commission (FERC). I currently advise a variety of regulatory commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. My resume is included as Exhibit FWR-1.

Q. COULD YOU PLEASE SUMMARIZE YOUR FINDINGS?

A. Yes. My testimony presents several adjustments to the Company's case. First, I propose four adjustments to the revenue forecast with the largest being that I do not believe the Company has provided sufficient data to demonstrate its sales are declining at the rate it predicts. I also adjusted rental income, revenues from forfeited discounts, and unbilled revenues. These adjustments reflect most recent trends in revenue streams and in the case of unbilled revenues to reverse the Company's assumption that no unbilled revenues would be booked in the test period. On the expense side, I made several adjustments to the depreciation study with the largest rejecting the change to use the Equal Life Group procedure which simply serves to increase revenue requirement. I also eliminated the revenue requirement associated with the installation of automatic meter reading devices because the Company's proposal provides it with the opportunity to realize cost savings while the ratepayers only receive a rate increase. I also adjusted uncollectible expense to more recent and reasonable levels and set the management fee that Columbia Gas of Kentucky pays to its holding company's service company to a reasonable level. Finally, I present the revenue impact of changing the allowed return on equity down to 8.5% instead of the requested 11.25%. The table below summarizes the revenue requirement impact of my adjustments.

		($000)
Requested Rev Increase	$	16,595
Adjustments to Revenue Requirement		
Sales (Company assumed very pessimistic based on very warm 2012)	$	(3,094)
Rent (set to most recent)	$	(77)
Late Payment (set to most recent)	$	(134)
Unbilled Revenues (set to historic)	$	(1,000)
Depreciation (No ELG and lower net salvage rates)	$	(2,829)
AMR (do not reflect in rates)	$	(420)
Uncollectibles (set to most recent)	$	(239)
NiSource (Last Rate Case Plus Inflation)	$	(2,347)
Rate Base Impact of Other Adjustments	$	(312)
ROE (8.5% vs. 11.25%)	$	(4,815)
Total	$	(15,267)
Recommend Increase	$	1,328

I also have one non-revenue requirement recommendation and that is to reject, as unnecessary, the Company's request to include a revenue requirement for property taxes in its AMRP Rider.

<u>II - SALES ADJUSTMENT</u>

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S SALES FORECAST?

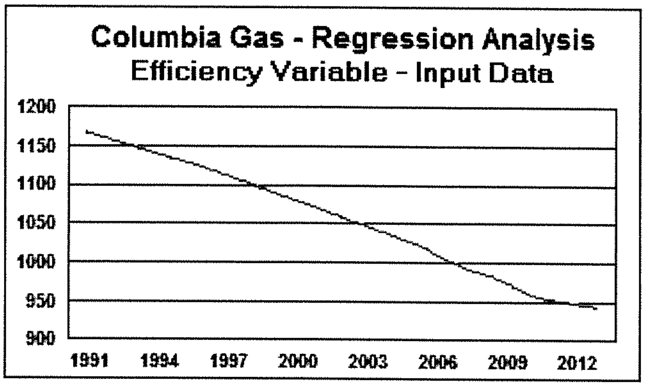
A. Yes. The Company's customer count and sales forecast was presented by Company witness William J. Gresham. The Company forecast sales in three components: Residential, Commercial and Industrial. For Residential and Commercial volume, forecast customer count and forecast use per customer are multiplied to get forecast throughput per customer class (Gresham Direct at page 5). Customer count for the Residential and Commercial classes are a two-part forecast with attrition of existing customers and new customer growth (Gresham Direct at page 3). Use per customer for the Residential and Commercial classes is forecast with separate econometric models that incorporate weather, real price, energy conservation, and economic conditions (Gresham Direct at page 5). Mr. Gresham explains that use per typical commercial customer is harder to develop and 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 (Gresham Direct at page 13). Sales volume for the Industrial class is internally generated by the Company and is based on discussions with customers on their upcoming plans, expected levels of gas consumption, historic consumption of the customer, and industry trends (Gresham Direct at page 6).

A key element to the Company's sales forecast is a perceived trend in residential usage. According to Mr. Gresham, weather normalized use per customer for residential customers has fallen 31% since 1993 and 17% over the last 10 years (Gresham Direct at page 10). He also believes that 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 (Gresham Direct at page 11). Declining usage for the commercial class and industrial class is not foreseen by the Company (Gresham Direct at page 13).

Q. COULD YOU PLEASE DISCUSS YOUR REVIEW OF THE SALES FORECAST?

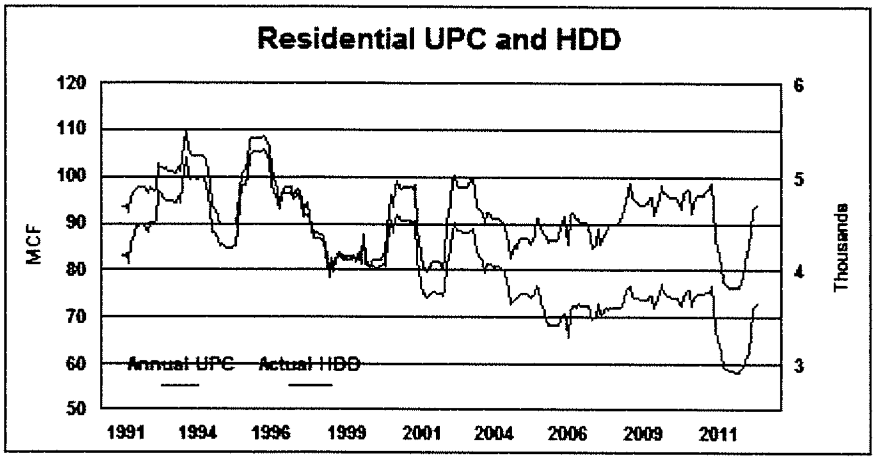
A. Yes. The first area of review was the declining use per customer for the Residential class and the graph that was included in Witness Gresham's testimony. Based on responses to discovery questions, the Company was unable to provide sufficient factual support for its claim that sales were declining. First, the Company was unable to provide work papers to support its claim that residential customer usage declined by 1.9% for the past ten years, nor was it able to produce any work papers that show customer usage declined by 1.2% for the past five years (Responses to AG questions 1-160 and AG 1-161). In addition, the means by which the Company weather normalizes sales is not based on a multi-variable regression analysis but rather a simple proration of temperature sensitive sales from actual heating degree days to normal heating degree days (Responses to Staff question 2-21).

Finally, the graph below shows the input data for the explanatory variable for energy conservation in the Company's econometric model. Even a casual review of the data shows that the variable simply assumes conservation is occurring at a rate of approximately 1% per year. When asked the source of this data, the Company responded that it came from an outside vendor and the data was not publically available (See responses to AG question 2-18). Thus, there is no independent way to determine how the data was developed, why it was developed, or its root source. As such, based on the Company's presentation, there is no independent means to determine if the energy conservation variable is a true independent explanatory variable or if it is just a simple coincidence that it correlates to use per customer as the Company determined in its statistical analysis.

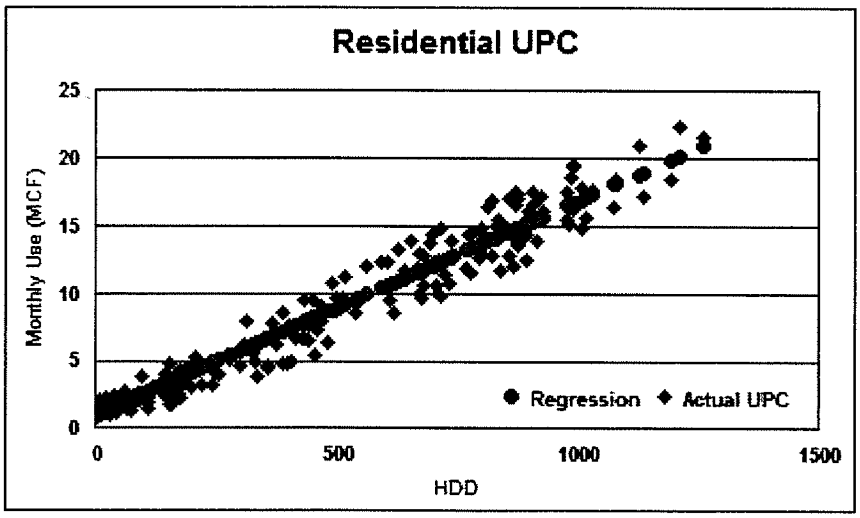


Q. HAVE YOU BEEN ABLE TO DETERMINE IF DECLINING USE IN THE RESIDENTIAL CLASS IS OCCURING?

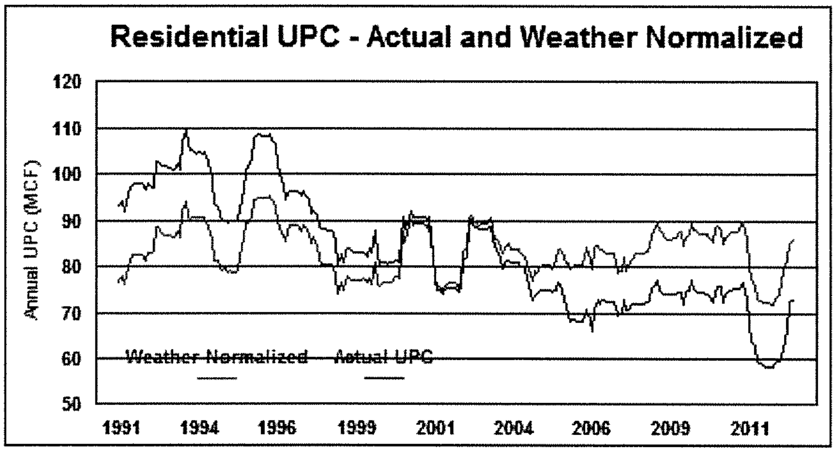
A. To answer that question I asked the Company for its econometric model input data and plotted the use per customer and heating degree days for the Residential class. For heating customers, the two main factors dictating their gas use is how cold it is outside and how windy it is. Obviously, the colder the day the more the furnace will run and the higher the gas use. Wind is the second greatest source of heat loss to a home. Winds cause heat loss by increasing the volume of cold wind blowing across the space; it can also force its way through cracks in the walls and windows, causing infiltration and drafts. Heating degree day is readily available but wind data is not. I plotted the annual use per customer and annual heating degree day for the 20+ years of available data on the graph below.



As can be seen from the graph, as it gets colder the use per customer increases; the warmer it is, the use per customer decreases. What cannot be determined from this graph is whether there is a trend in usage. To determine this, I ran a regression analysis of use per customer against heating degree days and found that they were very highly correlated (R-squared value of 0.96), as evidenced by the graph below.



Using the results to predict what sales should have been, factoring the weather, gives us a statistical prediction of weather normalized sales. Comparing this statistical output to actual allows us to get an indication of the trend in actual usage versus weather normalized usage. This data is plotted in the graph below and it shows that, when the effects of weather are accounted for, there has been a marked decrease in usage over a long period of time. That said, over the last one half dozen years that trend seems to have abated somewhat and usage has fluctuated in the low 70s of MCF per year for residential customers.



Q. ARE THERE ANY OTHER FACTORS THAT IMPACT THE RESIDENTIAL SALES FORECAST?

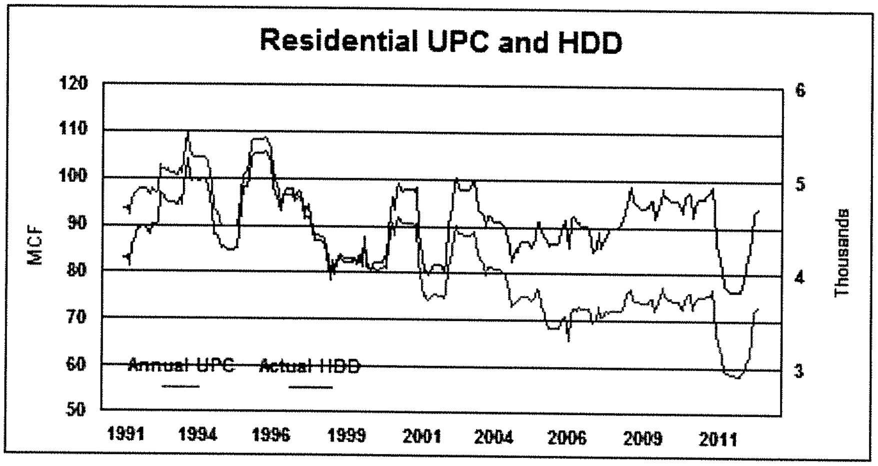
A. Yes. In response to discovery questions on how the sales volume was developed, Company witness Gresham explains that the econometric models are not used directly because the beginning point of the forecast is set to a take-off point (TOP) (Response to AG question 1-157). As Mr. Gresham explains, this take-off point eliminates the annual level of random error and allows for the professional judgment in setting the TOP (Ibid). He further explains that the TOP is an annual concept that is forecast with the trend from the use per customer models (Ibid). The use per customer is then forecasted out into the test year using the trends from the econometric models.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE COMPANY'S FORECAST OF THE SALES VOLUME FOR THE RESIDENTIAL CLASS?

A. When viewed objectively, the Company's forecast that sales are declining is nothing but a self-fulfilling prophecy. Here, without any model or analysis the Company analyzed the data and determined a TOP. Through discussions with itself it perceived a downward trend in sales and adjusted history accordingly (Response to AG question 1-157). Turning to the future, the Company developed a forecast based on the trend developed from the econometric model, which turns out to be an annual decrease of approximately 1% per year (Responses to AG question 1-157). At first blush, this would appear prudent if one is predicting normal weather in the future. However, the model assumes structural conservation is occurring and the model has an explanatory variable indicating that sales are decreasing at approximately 1% per year. In other words, the model is telling them exactly what they want to hear.

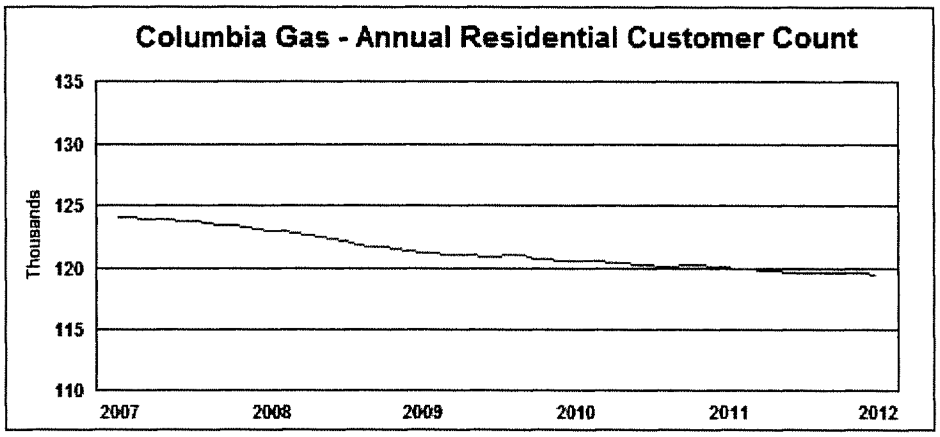
Q. WHAT DO YOU RECOMMEND TO USE FOR THE RESIDENTIAL SALES FORECAST?

A. The graph below shows the annual use per customer through June 2013. Sales have rebounded sharply from the lows of 2012 which was the latest data available to the Company when it made its forecast. The actual data shows annual heating degree days are approximately 4,500 days per year while current, annual use per customer is approximately 72 MCF per year. This includes all structural conservation to date and seems a reasonable number to use for the 2014 heating season, which is now only four months away. I recommend no other adjustment be made for declining use.



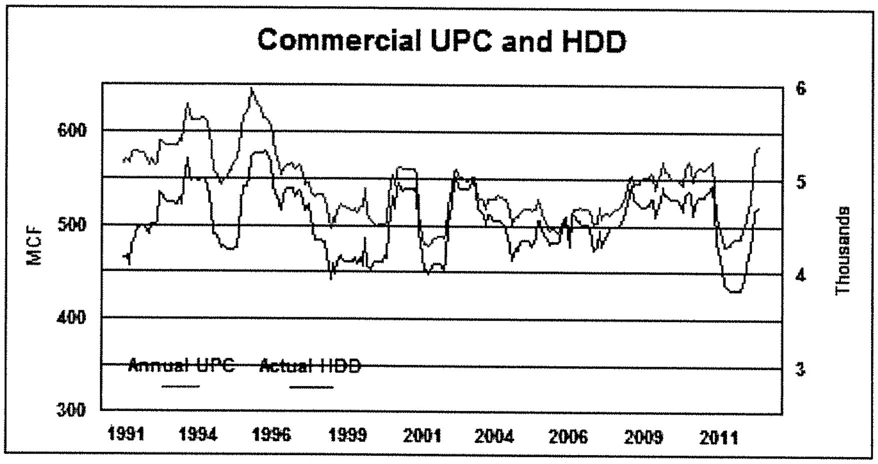
Q. WHAT DO YOU RECOMMEND FOR THE NUMBER OF CUSTOMERS FOR THE RESIDENTIAL CLASS?

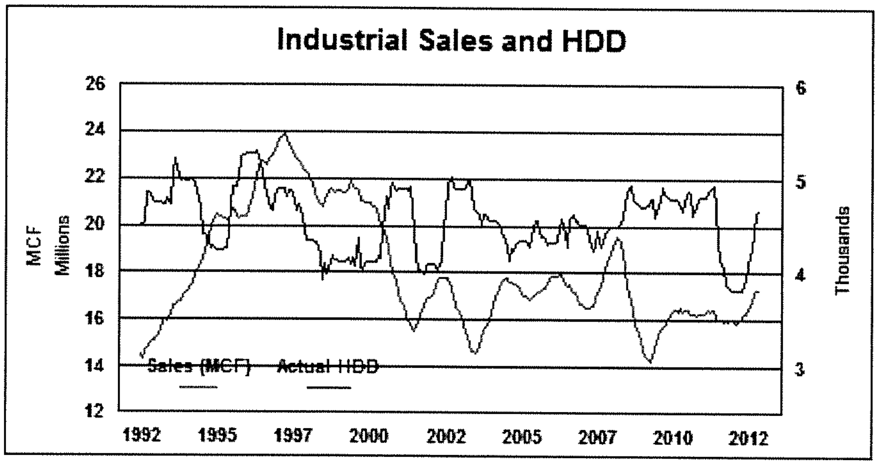
A. The Company is forecasting a continual decline of customers from 2011 levels. Based on data supplied by the Company, I was able to develop annual number of customers for the last six years. This data includes both new customers and customers lost due to attrition. Based on this data, it appears that the net loss of recent years has abated and a customer count for the test year of 120,000 customers seems reasonable. Based on this information, I forecast annual sales to the Residential class of 8.64 million MCF as compared to the Company's forecast of 7.995 million MCF.



Q. COULD YOU PLEASE DISCUSS YOUR SALES FORECAST FOR THE COMMERCIAL AND INDUSTRIAL CLASSES?

A. Yes. As noted above, the Commercial and Industrial classes are impacted by many things and the development of the sales forecasts for these classes is based more on judgment than modeling. The two graphs below show the annual use per customer for the commercial class and annual usage for the industrial class. A review of these graphs shows that usage is not entirely driven by heating degree days but other factors, which the company notes are economic and customer mix. In both cases, sales in 2012 were at an all-time low but have rebounded sharply in 2013. For the Commercial class, use per customer for the twelve months ending June 2013 was 586 MCF per customer per year. This is very favorable compared to the Company's TOP for the Commercial class of 486 MCF per customer per year. Sales to the Industrial class for the twelve months ending May 2013 were 17.2 million MCF, which is well above the Company test year forecast of 15.2 million MCF. The most recent data is more indicative of test year sales that begin in 4 months, as it reflects the most recent economic activity in Columbia Gas' service territory. A review of the forecast customer count for both the Commercial and Industrial classes show that the Company's forecasts are reasonable and should be used.





Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR ADJUSTMENTS?

A. Base revenues should be increased by $1.2 million for the Residential class, by $1.2 million for the Commercial class, and by $0.6 million for the Industrial class.

III - RENT

Q. COULD YOU PLEAE DISCUSS THE COMPANY'S FORECAST OF RENTAL INCOME?

A. The Company is forecasting rental from gas property at $16,623, which is very close to their base year forecast (Schedule D-1). Rental income changed shortly before the Company filed its rate case, with monthly rental income increasing from $1,402 to $7,798 (Response to AG question 1-218). The old rental income supported the Company's forecast, but with the increased rent is seems more reasonable to reflect the higher rent and set test year rental income at $93,576. This reduces revenue requirement by $76,953.

IV - FORFEITED DISCOUNTS

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S FORECAST OF REVENUES FROM ACCOUNT 487 – FORFEITED DISCOUNTS?

A. Yes, a sales discount is a price reduction a company offers a customer as an incentive to pay an invoice within a certain time period. A customer who fails to pay an invoice within the specified time period forfeits the discount and must pay the full amount. These forfeited discounts are recorded in revenue Account 487 – Forfeited Discounts. The Company has a test year forecast of forfeited discounts of $356,865 (Response to AG question 1-166, Attachment A, page 1 of 5) which was developed by using a six-year average of revenues from this account (Schedule D 2.1, Adjustment 2). The table below shows the revenues in this account for the past five years. Since the Company's last rate case in 2009 there is a notable increase in forfeited discounts, which is most likely the impact of aggressive collection actions by the Company and is evidenced by reduced uncollectibles. I see no reason not to reflect this level of activity in the test year and recommend a test year revenue amount of $490,806, which is the average of the last three years. This reduces the revenue increase by $133,941.

Year	Forfeited Discounts
2008	$192,713
2009	$209,255
2010	$493,928
2011	$572,294
2012	$406,197

V - UNBILLED REVENUE

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S FORECAST OF OTHER GAS REVENUES?

A. Yes. Account 495 - Other Gas Revenues is the account where revenues received from off system sales, miscellaneous fees and unbilled revenues are recorded. For the base period, the Company has a forecast of revenues in this account of $10,748,584 and a test year forecast of $385,220. The $385,220 is the amount forecast for miscellaneous fees and is a reasonable level when compared to historic levels. The Company states that it eliminated all revenues from Off System sales because these revenues are offset by the cost of those sales which are included as part of Columbia's Gas Cost Adjustment mechanism (Response to Staff question 3-5). This adjustment accounted for $5,701,218 of the total adjustment (Ibid). The Company has provided no reason as to why it eliminated unbilled revenue in the test period (Schedule D 2.1 Adjustment 2 and response to Staff question 2-7).

Q. WHAT ARE UNBILLED REVENUES?

A. Unbilled revenues are revenues recorded for services delivered but are as yet unbilled. For example, if your bill is read on December 15 you are billed for the usage from November 16 through December 15. When the Company closes its books for December, it records an unbilled revenue for the gas received between December 16th through 31st; it also records a reversal to the same account for the revenues received for the gas received between November 16th through 30th. The Company has supplied the unbilled revenues in response to AG questions 1-228 for the period 2009 through June 2013 and these values are summarized in the table below.

Year	Unbilled Revenues
2009	$8,571,999
2010	($4,342,007)
2011	$5,330,989
2012	$92,995
YTD	$5,524,994

Given the constant recording of unbilled revenues, averaging $3.3 million per year from the table above, there should be some be some evidence presented as to why no such reflection of unbilled revenues should be made. This is especially true with a test period ending December 31st, a month when sales are increasing and positive unbilled revenue is expected to be recorded. To reflect that expectation I propose to impute a $1 million level of unbilled revenues which would be net of gas costs and act to reduce the necessary revenue increase by $1 million.

VI - DEPRECIATION

Q. WHAT IS THE COMPANY PROPOSING FOR DEPRECIATION EXPENSE?

A. In the depreciation study prepared by Company Witness John Spanos (based on data available to December 31, 2012), Mr. Spanos used the straight line method of depreciation, with the equal life group procedure (Spanos Direct at page 12). Based on the results of Mr. Spanos' study, the Company is proposing to increase depreciation expense in the forecast test year from $7.2 million to $11.0 million (Responses to Staff Data Request 3-23).

Q. WHAT IS DEPRECIATION?

A. According to the Supreme Court of the United States:

> Broadly speaking, depreciation is the loss; not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy and obsolescence. Annual depreciation is the loss which takes place in a year.[1]

Another commonly cited definition comes from the American Institute of Certified Public Accountants which defines depreciation as follows:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT IS AN AVERAGE SERVICE LIFE?

A. The service life of any one unit of property is the number of years of service that the

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[1] *Lindheimer v. Illinois Bell Telephone Company*, 292 U.S. 151, 167 (1934).

property lasts. For example, while there may be many thousands of utility poles on a utility's system, each pole's service life is going to be impacted by its location, environment and outside forces impacting it. Thus, while two poles may have been placed into service on the same day, one pole might be close to a main street while the other might be placed in a rural area with sandy, well-drained soil away from any nearby trees. The first pole might only survive for two or three years while the second might be in service for sixty or seventy years. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

Q. WHAT IS AN IOWA CURVE?

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves or L-Curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. Think of a type of property where some might not last very long but then others might last a very long time. One might imagine that this could occur with Chevrolet Corvettes, where some are driven at high speed and crashed while other are cherished and pampered in the garage. If a substantial proportion is retired early compared to the average, the curve is moded to the left. The symmetrical moded curves, or S Curves, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, or R Curves, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, or O Curves, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

Q. WHAT IS NET SALVAGE?

A. Net salvage is the value obtained from retired property (the gross salvage) less the cost removal. Net salvage can be either positive or negative. Net salvage can be positive in cases where the salvage value of the property exceeds the cost of removing the property. For example, when one sells a truck it costs little or nothing for the utility to consign a number of trucks to a dealer and the money received offsets the original cost of the truck. Net salvage can be negative as well in cases where cost of removal is greater than gross salvage. An old utility pole has little if any salvage value but a truck and crew must be still dispatched to remove it.

Q. HOW DOES NET SALVAGE IMPACT THE CALCULATION OF DEPRECIATION?

A. The intent of the depreciation process is to allow the Company to recover 100% of investment less net salvage. Therefore, if net salvage is a positive 10%, then the utility should only recover 90% of its investment through annual depreciation charges under the theory that it will recover the remaining 10% through net salvage at the time the asset retires (90% + 10% = 100%). Alternatively, if net salvage is a negative 10%, then the utility should be allowed to recover 110% of its investment through annual depreciation charges so that the negative 10% net salvage that is expected to occur at the end of the property's life will still leave the utility whole (110% - 10% = 100%).

Q. WHAT IS A DEPRECIATION RATE?

A. The depreciation rate is expressed as a percentage and is calculated by subtracting the net salvage percent from 100% and then dividing by the remaining average service life. For example, for an account with a net salvage of negative twenty percent and a forty year remaining service life, then the depreciation rate would be 100% less negative 20% to arrive at a figure of 120% divided by 40 to arrive at a depreciation rate of 3.0%.

Q. WHAT IS DEPRECIATION EXPENSE?

A. The depreciation expenses of a utility are determined by applying approved depreciation rates to the depreciable plant balances. The rates are developed separately for particular classes of plant, such as production (e.g., gas-fired generation, coal-fired generation), transmission, distribution, etc., based on detailed studies.

Q. WHAT IS THE DEPRECIATION RESERVE?

A. While depreciation expense represents the annual recovery of the capital investment, there is another depreciation category that records all depreciation expense, retirements, cost of removal and gross salvage on a continuous basis. This account is the accumulated provision for depreciation, also known as the depreciation reserve. The depreciation reserve serves as a "running total" of the extent to which individual assets or groups of assets have been depreciated. In a depreciation study, the depreciation reserve is known by several other names as well, the most notable being the "book reserve," the "recorded reserve" or the "actual reserve."

Q. WHAT IS A DEPRECIATION STUDY?

A. A depreciation study is the process whereby each account is examined to determine the appropriate survivor curve, average service life, and net salvage rate to be used in the calculation of depreciation rates, thereby allowing calculation of depreciation expense which would allow the utility to properly recover its invested capital.

Q. PLEASE DISCUSS THE COMPANY'S PRESENTATION IN THIS CASE.

A. Mr. Spanos recommends using the equal life group procedure to calculate depreciation expense. The procedure applies to how to weight the remaining life of assets in an account in order to calculate the remaining life. As more fully explained in Mr. Spanos' deprecation study (Filing Requirement 12-S), under the equal life group the property in an account is subdivided according to service life and each group is depreciated over its own service life. As such, equipment with a shorter than average service life will be depreciated faster than the average and plant with a longer average service life will depreciate slower (i.e. longer average service life). This procedure is different than the average service life procedure whereby the accrued depreciation is based on the average service life of the group. A key characteristic of this procedure is that the cost of plant retired prior to the average service life is not fully recouped and plant retired subsequent to the average life is more than fully recouped.

Q. WHAT PROCEDURE IS IN PLACE NOW FOR COLUMBIA GAS OF KENTUCKY, INC.?

A. The average service life procedure. Mr. Spanos recommends the use of the equal life group because he believes it is the most accurate for matching recovery of the asset to consumption or utilization of the asset (Spanos Direct at page 19). That said, Mr. Spanos also notes that the average service life procedure is most commonly utilized in Kentucky (Spanos Direct at page 18).

Q. WHAT IS THE IMAPCT OF SWITCHING FROM THE AVERAGE SERVICE LIFE PROCEDURE TO THE EQUAL LIFE GROUP PROCEDURE?

A. Based on December 31, 2012 data, moving to the equal life group procedure would increase depreciation expense by $3.2 million (Response to AG question 1-92).

Q. COULD YOU PLEASE COMMENT ON THE PROPOSED CHANGE IN DEPRECATION PROCEDURES?

A. The Company has proposed changing to the equal life group procedure in its last three rate cases (Case No. 2002-00145, Case No. 2007-00008 and Case No. 2009-00141). In each of those cases, which were settled and the parties agreed to depreciation rates specifically based on the average service life procedure. (See Case No. 2002-00145, KPSC Order dated 12/13/2002 approving the Settlement Agreement; Case No. 2007-00008, KPSC Order dated 8/29/2007 approving the Stipulation and Stipulation Supplement; and Case No. 2009-00141, KPSC Order dated 10/26/2009 approving the Stipulation and Recommendation.) The company has failed to demonstrate the need to switch from the average service life procedure. Moreover, the Company will not be denied any rate recovery for deprecation since both the average service life procedure and the equal life group procedure provide for full recovery. Accordingly, I recommend that equal life group procedure not be adopted.

Q. DO YOU RECOMMEND ANY OTHER CHANGES TO THE COMPANY'S PROPOSED DEPRECATION RATES?

A. Yes, for Account 376 – "Mains" and Account 380 – "Services", the increased retirement activity from the accelerated main replacement program is affecting the indicated net salvage rates. For Account 380 in the period 1969-2000 retirements on an annual basis ranged from a low of $24,000 to a high of $750,000 with net salvage rates ranging between (39%) to (454%) (Filing requirement 12s, page III-110). Since that time however, and particularly after the introduction of the accelerated main replacement program, retirements around $900,000 per year and net salvage ranges have declined dramatically with the last five years, averaging (50%). For Account 376, the change in retirements and net salvage follow a similar pattern. For the period between 1969 and

2000, retirements ranged from a low of $37,000 per year to a high of $650,000 with net salvage rates ranging between (4%) to (20%) (Filing Requirement 12s, page III-101). More recent years show retirements in the $900,000 to $1,200,000 per year range and net salvage rates for the years with high retirements between (6%) to (10%). The most likely cause of the lower net salvage rates is because the Company is being proactive in planning a retirement for larger sets of assets as opposed to be being reactive when a leak occurs and retiring a smaller asset. Because of this the retirement activity field work is spread across a larger asset base, resulting in lower net salvage rates. Given that the utility proposes to continue with the accelerated main replacement programs, I believe the most recent results are more indicative of future net salvage rates. Accordingly, I proposed that the net salvage rates for these accounts reflect that development. For Account 376 I propose a net salvage rate of (10%) as opposed to the recommended (15%), and for Account 380 I propose a net salvage rate of (50%) as opposed to the Company's proposed (60%). These recommendations lower depreciation expense in the test period by $520,000.

VII - AUTOMATED METER READING

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PLAN FOR INSTALLING AUTOMATED METER READING DEVICES?

A. Yes, automated meter reading devices (AMRs) allow the Company to read people's meters electronically instead of having meter readers come to each service location and physically read the meter. The AMR device attaches to the gas meter and encodes consumption information from the meter to the radio-equipped data sending device (Belle

Direct at page 11). The AMR devices transmit data to a radio-equipped handheld computer or vehicle-based mobile computer collection system (Ibid). These gas modules work equally well in-doors and outdoors and are powered by lithium batteries that provide an average battery life of 20 years (Belle Direct at page 12).

The Company began installing AMRs in 2008 in target "hard to access" meters and new or refurbished meters with AMD devices pre-installed (Response to AG question 1-15). These target AMR installations resulted in no savings during the past five years (Ibid). Over the course of 2014, Columbia plans to install AMR devices for all customer classes and intends to spend approximately $7 million on installing and implementing an AMR system (Belle Direct at page 11 and response to AG question 1-299). The mass deployment of AMRs is planned for 2014; Operations and Maintenance expense savings are anticipated starting with the fourth quarter of 2014, resulting in an estimated reduction of $199,731 to 2014 O&M expense (Response to AG question 1-15). For 2015, net savings is anticipated to be approximately $741,000 (Ibid). For 2016 and beyond, savings are anticipated to be approximately $767,000 (Ibid).

Q. WHAT IS THE REVENUE REQUIRMENT ASSOCIATED WITH INSTALLING THE AMRs?

A. The Company estimates that the test year impact of installing the AMRs is to increase the revenue requirement in this case by $419,731 (Responses to AG question 1-295, Attachment A, page 3 of 4).

Q. WHO BENEFITS FROM THE ADDITIONAL SAVINGS IN OPERATION AND MAINTENANCE EXPENSE THAT THE COMPANY FORECASTS IN 2015, 2016, AND BEYOND?

A. The Company and only the Company.

Q. DO CUSTOMERS BENEFIT FROM AMR TECHNOLOGY?

A. The Company states that customers do benefit. The benefits include 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 (Belle Direct at page 12).

Q. COULD YOU PLEASE COMMENT ON THE CLAIMED CUSTOMER BENEFITS?

A. Yes. Most of the claimed benefits have little material quantitative value to customers. Increased meter reading performance has almost no benefit to customers. If a meter read is too low, the next bill will recover that with somewhat higher usage. If the meter read is too high, the next meter read will indicate somewhat lower usage. Either way the customer is indifferent in the long run. As to improvements in customer satisfaction and reduced rebilling due to hard-to-access meters, the Company started addressing this issue on its own in 2008 when it began installing AMRs. As to reduced energy theft, the Company already has an incentive to do this and AMRs only assist the Company in its current efforts but does not replace them. Increased employee safety may occur as there will be fewer on-the-job injuries, but since the Company plans to eliminate most meter reading positions, there is no justification for the AMR to be categorized as a benefit to the ***customer***.

More importantly, in response to discovery, the Company states that the new AMR system will not provide real time gas usage information and an AMR device will not, in and of itself, result in the reduction of gas usage (Responses to AG questions 1-16 and 1-45).

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW?

A. It is clear that the installation of AMRs will produce savings for the Company in the very near term, and that is certainly a good thing from a shareholder perspective. From the ratepayer perspective, however, the AMRs cost $419,731per year and the benefits are mostly slight improvements in billing administration for the company. In my review I was also disheartened to learn that the Company has not even applied to its parent Company NiSource for capital allocation and authorization on this project (Response to AG question 1-296). Apparently if the Kentucky Public Service Commission approves the increased revenue requirement, Columbia Gas will proceed with the project. On balance, I do not see that these benefits outweigh the cost of supporting the new technology and I recommend that no increased revenue requirement be allowed to support it. If the Company still believes that this project will provide benefits to it without ratepayer support (i.e. savings in operation and maintenance expenses pay for carrying charges on the capital investment), they are certainly allowed to do so.

VIII - UNCOLLECTIBLES

Q. WHAT IS THE COMPANY'S FORECAST OF UNCOLLECTIBLE EXPENSES?

A. The Company is seeking recovery of uncollectible expense of $839,477 (Response to AG question 1-66, Attachment A, page 3 of 5). To get this number they took base period uncollectibles and made two adjustments, the first to develop an estimated uncollectible amount (Schedule D-2.2, adjustment 10) and one to reflect the estimated net charge off rate (Schedule D-2.4, adjustment 4).

Q. IS THE COMPANY'S ESTIMATE REASONABLE?

A. The table below which was taken from the response to AG question 1-166 shows the historic amounts on write offs charged to Account 904 – Uncollectibles. As can be seen from the table, the amount of uncollectibles has dropped dramatically.

Year	Uncollectible Expense
2008	$2,451,089
2009	$1,991,631
2010	$1,230,283
2011	$594,185
2012	$534,473

Uncollectible expense for the twelve months ending June 2013 was $397,531 and the uncollectible expense for the twelve months ending July 2013 was $691,364 (Responses to AG questions 2-16 and 2-17). With the recent low levels of uncollectible expense, I believe the Company's forecast is too high and I recommend a level more in line with most recent experience. I reject the Company's method of setting uncollectibles as some percentage of revenues because of the fact that the commodity cost of gas varies so much from year to year it makes this method unreliable. Based on information from 2011, 2012, and the latest twelve the uncollectible expense level is very close to $600,000 per year and I recommend that the uncollectible expense level be set at $600,000.

<u>IX - MANAGEMENT FEE</u>

Q. PLEASE DISCUSS THE COMPANY'S FORECAST OF MANAGEMENT FEE?

A. The Company is forecasting a test level of total management fee paid to NiSource Services Corporation Company (NiSource) of approximately $12.7 million, which is an estimate provided by NiSource (Schedule D 2.2, Adjustment 9). While the management fees are spread across many accounts, the single largest charge is to Account 923 – Outside Services Employed. For the test year the Company is forecasting outside service expense of $9,820,857 (Responses to AG question 1-666, Attachment A, page 4 of 5). Based on the Company's reply to AG question 2-14, the vast majority of charges in this account are payments made to NiSource. For the example, for 2012, the Company had a total of outside services expense of approximately $9.3 million, of which $9.0 million or 97% were for expenses paid to NiSource (Response to AG question 2-14, Attachment A). Payments to NiSource were at least 96% of all outside services expenses in 2008-2011 as well (Ibid).

Q. WHAT LEVEL OF MANAGEMENT FEE WAS ESTIMATED IN THE LAST

RATE CASE?

A. In the Company's last rate case, the management fee to NiSource was estimated to be \$9.7 million with \$6.6 million charged to Account 923 (Case 2009-00141, Schedule D-2.8). Seen another way, the estimated overall management fee has grown at an annual rate of approximately 5.6% and the outside services expense has grown at a rate of approximately 7.6%. Actual expenses have tracked estimates. Total billings from NiSource to Columbia Gas in 2009 were \$11.1 million, which included charges for both expenses and work on capital projects (Volume 7, Tab 58, pages 5-6). Total billing from NiSource in 2012 was \$13.4 million, which represents a 6.9% annual growth rate.

Q. HAS COLUMBIA BEEN ASKED TO EXPLAIN THESE LARGE INCREASES IN BILLINGS?

A. Yes, Staff question 2-3 addressed this very point. In that same question Staff also asked why the Company was forecasting larger than inflation increase between 2012 and the test year. The Company gave a thoughtful and detailed five page explanation to staff (Response to Staff question 2-3). Among the reasons for the increase were increased staffing needs, increased volume of calls from customers, and increased expenses due to implementation of new technologies (Ibid). While all of these seem like clear and reasonable explanations of why an expense category increases, what is missing from the response is an explanation of offsetting efforts by the Company to control costs. This is surprising, as one of the much-touted benefits of holding companies are synergies and the lower cost of centralized operations.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS ISSUE?

A. In cases where holding companies allocated costs amongst subsidiaries, one means by which to assure reasonable allocation is to establish a clear set of accounting and allocation methods which are periodically reviewed and audited for reasonableness. NiSource has such an allocation basis – it was presented in this case as filing requirement 12-U. That does not always ensure low rates, however, as problems can arise when allocating between states and across line divisions. Indeed, this happened in the Northeast area of the country where one utility was subject to an audit and glitches found in the system caused one regulatory commission to order changes in the utility's accounting practices (http://www.timesunion.com/business/article/Utility-audit-cites-44M-4202345.php). I should note the audit method of regulation did not work well for this holding company as no less than three states conducted independent audits of its accounting practices; the utility also had to do its own internal audit which cost it over $2 million; and, since the time the accounting glitches were found, the regulators have ordered two other audits of its operating business practices.

Another method of utility oversight is incentivized ratemaking. This method sets targets for performance wherein the utility can earn extra money if it performs well or is penalized if it performs poorly. For example, one might set a target rate of contractor damages to gas lines and develop a performance mechanism around that target to reward or penalize for performance. It is important to note that incentivized ratemaking is not symmetrical and the penalty for bad performance could be worse than the incentive for good performance. Using the contractor damage example, if a utility was found to be one of the worst in the country on policing the work performance of a contractor, the regulator may find it appropriate to make penalize for continued poor performance and distribute smaller rewards for improved performance. Another method to incentivize utility performance is to impute productivity improvements in rates. This may be done through a productivity adjustment to labor or through a straight imputation of synergy benefits (a common method when dealing with mergers) or by simply limiting the inflation level applied to certain expense categories.

Q. WHAT DO YOU RECOMMEND BE DONE IN THIS CASE?

A. First, I would note that the vast majority of expenses being paid to NiSource are accounted for in Outside Services, which is almost like a catch-all for fees paid to the parent company. Based on the last rate case, the current rates have approximately $9.7 million in total management fee paid to NiSource. With the management fee forecast in this case set at $12.7 million, one way to look at the rate request of $16.6 million is that $3.0 million – or 18% – of the rate request is being driven by the management fee to NiSource.

While one can appreciate that the Company is incurring costs for new technologies and increased regulatory reporting requirements, one must recognize that very little can be gleaned from what goes into this charge without a detailed audit of the Company. In addition, with a utility bemoaning about declining sales (yet has automatic rate recovery for its pipe replacement program), one can easily understand why ratepayers would expect the utility to be pinching pennies and finding ways to achieve productivity improvements. To address this need for balance between shareholder and ratepayer, I believe an incentive mechanism, rather than an audit at this time, should be adopted that provides an impetus for the parent company to control costs. Perhaps the simplest, most direct and administratively easy solution is to limit the increase in management fee to the increase in the CPI since 2009. The CPI for 2009 was 642 and the CPI for 2012 was 688 for an increase of 7.1% to get to mid-year test year. If we apply a 3% inflation factor to 2012 level we get a test year CPI of 730 or 13.7% higher than 2009. Applying this factor to the management fee currently in rates gives a management fee of $11.1 million. This reduces test year revenue requirement by approximately $1.7 million.

X - RETURN ON EQUITY

Q. COULD YOU PLEASE DISCUSS THE AG'S POSITION ON RETURN ON EQUITY?

A. Yes, the AG is not sponsoring a witness to propose a return on equity in this case. My testimony serves to provide prospectus on what the overall revenue requirement may be for this Company given returns on equity that have been recently awarded throughout the country. For example, in a recently completed rate case in Connecticut, the Public Utility Regulatory Authority (PURA) awarded the United Illuminating Company a 9.15% return on equity in Docket No. 13-01-19. This electric distribution Company had asked for a 10.25% return on equity. In its final decision in the Docket issued August 14, 2013 PURA noted that the median in the third quarter of 2013 allowed returns on equity that are continually trending downward, with reports by Regulatory Research Associates showing that in the third quarter of 2013 allowed ROEs ranging between 9.30% to

10.20% and averaged 9.73%. Kentucky has not been immune from the trend in lower recommended rates of return. In Case No. 2012-00520, testimony filed as recently as April 2013, the AG witness noted his analysis of an equity cost rate in the range of 7.3% to 8.6% for Kentucky American Water Company. (See Direct Testimony of J. Randall Woolridge, filed April 3, 2013, as Exhibit FWR-2.) With these returns on equity so much lower than that requested by Columbia, it is proper to give an illustrative return on equity in the low 7.3% to 9.7% range. In my calculated revenue requirement I am using a return on equity of 8.5%. Columbia reports that the impact of a lower return on equity is a linear function and for each 50 basis points it reduces the revenue requirement in this case by $875,445 (Responses to AG questions 1-119, 1-120 and 1-212). Based on an 8.5% return on equity as compared to the Company's request of 11.25%, this adjustment reduces revenue requirement by approximately $4.8 million.

XI – PROPERTY TAXES IN AMRP

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSAL TO INCLUDE PROPERTY TAXES IN THE AMRP RIDER?

A. Yes, Company Witness Judy M. Cooper testifies that the Company 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 (Cooper Direct at page 8). Thus, she proposes to change the language for the AMRP Rider to simply include property taxes (Filing Requirement Schedule L, Tariff Sheet 58).

Based on a discovery question on the timing of taxes on new plant addition the Company described the taxing process as follows: Columbia's property tax liability is based on an assessed value as of December 31. For example, taxes for tax year 2012 are assessed on property as of December 21, 2011, with bills due starting in the fourth quarter of 2012 and continuing into 2013 (Response to AG question 1-214). With this taxing system it is unreasonable for the Company to ask for property tax expense for plant being put into service in a forecast test year since they will not be assessed any taxes until the following year with taxes to be paid at the end of that year or in the first quarter of the next (Response AG question 1-215). As such, I propose rejecting the Company's proposal as unnecessary.

Q. DOES THIS CONCLUDE YOUR TESITMONY?

A. Yes it does.

COLUMBIA GAS OF KENTUCKY
REVENUE DEFICIENCY

	Columbia (1)	Adjustment	AG	
1. Rate Base	$203,298,499	$ (2,132,443)	$ 201,166,056	FWR-3
2. Rate of Return	8.59%		7.15%	FWR-2
3. Operating Income Requirement	17,463,341		14,377,942	
4. Pro Forma Operating Income	7,398,960	6,168,971	13,567,931	FWR-5
5. Operating Income Deficiency	10,064,381		810,010	
6. Gross Revenue Conversion Factor	1.648940		1.639537	(2)
7. Revenue Deficiency	$ 16,595,561	$ (15,267,519)	$ 1,328,042	

(1) Schedule A

	Columbia	AG	
(2) Operating revenue	100.000000%	100.000000%	
Less: Uncollectible accounts	-0.56896%	-	Sch. FWR-9
Less: PSC fees	-0.17540%	-0.17540%	
Net revenues	99.2556%	99.824600%	
State income taxes @ 6.00%	0.059553	5.989476%	
Income before federal income tax	0.933003	93.835124%	
Federal income tax @ 35%	0.326551	32.842293%	
Operating income percentage	0.606452	60.992831%	
Gross revenue conversion factor	1.648935	1.639537	

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Sch. FWR-2

COLUMBIA GAS OF KENTUCKY
RATE OF RETURN

COLUMBIA PROPOSED:

	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Short Term Debt	0.270%	1.94%	0.01%
Long Term Debt	47.340%	5.68%	2.69%
Common Equity	52.390%	11.25%	5.89%
Total	100.00%		8.59%

AG RECOMMENDED:

	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1) and (2)	Ratio X cost Rate
Short Term Debt	0.270%	1.94%	0.01%
Long Term Debt	47.340%	5.68%	2.69%
Common Equity	52.390%	8.50%	4.45%
Total (Equal to Rate Base)	100.00%		7.15%

(1) Schedule J-1, page 1 of 2
(2) Testimony of Frank Radigan

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Sch. FWR-3

COLUMBIA GAS OF KENTUCKY
RATE BASE

	Columbia (1)	Adjustment	AG	
1. Plant In Service	$356,161,789		$ 356,161,789	
2. Accum. Depreciation & Amort.	(138,958,740)	(1,756,667)	(140,715,407)	FWR-11
3. Construction Work in Progress	-		-	
4. Cash Working Capital Allowance	4,081,898	(375,775)	3,706,123	FWR-4
5. Other Working Capital Allowances				
a. Materials & Supplies	74,783		74,783	
b. Gas Stored Underground	38,936,027	-	38,936,027	
c. Prepayments	433,436		433,436	
d. Total Working Capital	39,444,246		39,444,246	
6. Customer Advances	-		$ -	
7. ADIT & ADITC	(57,430,695)		(57,430,695)	
8. Net Rate Base	$203,298,498	$ (2,132,442)	$ 201,166,056	

(1) Schedule B-1

COLUMBIA GAS OF KENTUCKY
CASH WORKING CAPITAL ALLOWANCE

	Columbia (1)	Adjustment	AG	
1. Total Pro Forma O&M Expense Exclusive of Purchased Gas Costs	$ 32,655,187	$ (3,006,202)	$ 29,648,985	FWR-5
2. CWC Ratio	0.125	0.125	0.125	
3. Cash Working Capital	$ 4,081,898	$ (375,775)	$ 3,706,123	

(1) Schedule B-5.2

COLUMBIA GAS OF KENTUCKY
PRO FORMA OPERATING INCOME

		Columbia (1)	Adjustment	AG	
1.	Operating Revenues	$ 93,147,657	$ 4,305,063	$ 97,452,720	FWR-6
	Operating Expenses:				
2.	Gas Supply Expenses	37,562,527		37,562,527	
3.	Other Operating Expenses	32,206,191	(3,006,202)	29,199,989	FWR-7
4.	Depreciation Expenses	11,548,354	(2,829,000)	8,719,354	FWR-11
5.	Taxes Other Than Income Taxes:	3,525,110		3,525,110	
6.	Operating Exp. Before Income Taxes	84,842,182	(5,835,202)	79,006,980	
7.	Operating Income Before Income Taxes	8,305,475	10,140,264	18,445,739	
8.	Income Taxes	906,515	3,971,293	4,877,808	FWR-12
9.	Operating Income	$ 7,398,960	$ 6,168,971	$ 13,567,931	

(1) Schedule C-2

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Sch. FWR-6

COLUMBIA GAS OF KENTUCKY
RECOMMENDED OPERATING REVENUES

1. Operating Revenues Proposed by Columbia:	$	93,147,657	(1)
AG-Recommended Revenue Adjustments:			
2. Sales adjustment to reject TOP and declining sales argument	$	3,094,168	FWR-6A
3. Incremental Forfeited Discount Revenues	$	133,941	FWR-6B
4. Rent	$	76,953	FWR-6B
5. Unbilled Revenues		1,000,000	FWR-6B
5. Operating Revenues Recommended by AG	$	97,452,720	

(1) Schedule C-1, line 1

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COLUMBIA F KENTUCKY
RETAIL S/ JUSTMENT

Rate Schedule	Residentail (1) Bills	MCF	Current Cust. Chg. Rev	Current Base Usage Rev	Current AMRP Rev
Residential					
GIC	1,439,306	7,995,392	$17,775,429	14,963,376	1,525,664
GSO					
IS					
IUS					
GTO					
DS					
GDS					
DS3					
FX1					
FX2					
FX5					
FX7					
SC3					
TOTAL PER COLUMBIA FORECAST	1,439,306	7,995,392	$ 17,775,429	$ 14,963,376	$ 1,525,664
Average (Usage, Revenue Per Bill or Revenue Per MCF)		66.66	$ 12.35	$ 1.87	1.06
AG Use Per Customer (Radigan Testimony)		72			
AG Sales Forecast (Radigan Testimony)		8,640,000			
Incrmental (Sales -MCF or Bills)			694	644,608	694
Revenue Impact (Average Rate Times Incremental)			$ 8,571	$ 1,206,384	$ 736
Grand Total Revenue Impact	$3,094,168				

Rate Schedule	Commercial (1) Bills	MCF	Current Cust. Chg. Rev	Current Base Usage Rev
Residential				
GIC	48	2,707	$1,680	$5,722
GSO	114,076	2,828,575	$2,866,730	$5,177,564
IS				
IUS				
GTO	49,717	1,843,987	$1,249,388	$3,350,852
DS	348	1,775,557	$222,473	$970,697
GDS	194	314,668	$15,720	$527,099
DS3				
FX1	12	378,925	$7,672	$47,366
FX2				
FX5				
FX7				
SC3				
TOTAL PER COLUMBIA FORECAST	164,395	7,144,418	$ 4,363,663	$ 10,079,300
Average (Usage, Revenue Per Bill or Revenue Per MCF)		521.51	$ 26.54	$ 1.41
AG Use Per Customer (Radigan Testimony)		586		
AG Sales Forecast (Radigan Testimony)		8,027,956		
Incrmental (Sales -MCF or Bills)				883,537
Revenue Impact (Average Rate Times Incremental)				$ 1,246,489

Rate Schedule	Industrial (1) Bills	MCF	Current Cust. Chg. Rev	Current Base Usage Rev
Residential				
GIC				
GSO	467	156,320	$11,736	$265,183
IS	12	33,099	$7,001	$18,095
IUS				
GTO	145	48,000	$3,644	$83,291
DS	444	5,622,821	$283,845	$2,623,290
GDS	209	212,264	$16,935	$359,497
DS3	36	767,283	$9,212	$65,833
FX1				
FX2	12	366,000	$7,672	$45,750
FX5	36	3,491,291	$9,212	$299,553
FX7	12	480,000	$7,672	$195,600
SC3	12	4,009,476	$7,672	$875,516
TOTAL PER COLUMBIA FORECAST	1,385	15,186,555	$ 364,601	$ 4,831,608
Average (Usage, Revenue Per Bill or Revenue Per MCF)		131,580	$ 263.25	$ 0.32
AG Use Per Customer (Radigan Testimony)		149,025		
AG Sales Forecast (Radigan Testimony)		17,200,000		
Incrmental (Sales -MCF or Bills)				2,013,445
Revenue Impact (Average Rate Times Incremental)				$ 631,988

(1) Response to AG 1-263, Attachment A

Forefeited Discouunts

Columbia (1)		$ 356,865

Year	Forfeited Discounts
2008	$192,713
2009	$209,255
2010	$493,928
2011	$572,294
2012	$406,197

OAG Forecast - 3yr average (Avg. 2010-2012)	$ 490,806
Recommended incremental revenues	$ 133,941

Rent

Columbia (2)	$ 16,623
OAG - Reflect latest rent amount of $7,798 per month (3)	93,576
Recommended incremental revenues	$ 76,953

Unbilled Revenues

Columbia (4)	$ -

Year	Unbilled Revenues
2009	$8,571,999
2010	($4,342,007)
2011	$5,330,989
2012	$92,995
YTD	$5,524,994

OAG - Forecast to reflect some revnues in recognition of historic activity (5)	1,000,000
Recommended incremental revenues	$ 1,000,000

(1) Response to AG question 1-166, Attachment A, page 1 of 5
(2) Schedule D-1
(3) Response to AG question 1-218
(4) Response to Staff question 3-5
(5) Response to AG questions 1-228

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Sch. FWR-7

COLUMBIA GAS OF KENTUCKY
OTHER OPERATING EXPENSES

1.	Other Operating Expenses Proposed by Columbia:	$ 32,206,191	(1)
	AG-Recommended Expense Adjustments:		
2.	Automated Metering Infrastructure	(419,731)	FWR-8
4.	Uncollectible Expense Adjustment	(239,467)	FWR-9
6.	NiSource Cost Allocation Adjustments	(2,347,004)	FWR-10
8.	Other Operating Expenses Recommended by AG	$ 29,199,989	

(1) Schedule C-1, line 4

COLUMBIA GAS OF KENTUCKY
AUTOMATED METER READING ADJUSTMENT

	Columbia (1)	Adjustment	AG
1. Estimated Revenue Requirement AMR	$ 419,731	$ (419,731)	$ -
6. AMR Adjustment		$ (419,731)	

(1) See Response to AG 1-293, Attachment A, page 3 of 4, Section 1 (d) Rate Case Revenues

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Sch. FWR-9

COLUMBIA GAS OF KENTUCKY
UNCOLLECTIBLE EXPENSES

	Columbia		Adjustment	AG	
1. Base Year Uncollectibles	$ 731,066	(1)		$ 731,066	
4. Test Year Expennse	$ 839,467	(2)	$(239,467)	$ 600,000	(3)
5. Residential Uncollectible Expense Adjustment	$ 108,401		$(239,467)	$ (131,066)	

(1) Schedule D-2.1, Sheet 5

(2) Per response to AG-1-166, Attachment 5, page 3 of 5, line 5

Year	Uncollectible Expense
2008	$2,451,089
2009	$1,991,631
2010	$1,230,283
2011	$594,185
2012	$534,473

(3) Per Responses to AG questions 2-16 and 2-17. Uncollectible expense for the twelve months ending June 2013 was $397,531 and the uncollectible expense for the twelve months ending July 2013 was $691,364. Level seems to be gravitating around $600,000 per year and that is what is recommended

Test Period Ending 12/31/14
Case No. 2013-00167

Sch. FWR-10

COLUMBIA GAS OF KENTUCKY
NISOURCE CORPORATE SERVICE COST ADJUSTMENT

1. NiSource Service Costs Allocated to Columbia			$	12,733,636	(1)
AG-Recommended Adjustments:					
2. Magement Fee From 2009 Case			$	9,148,390	(2)
		CPI			
3. Inflation Adjustment	2009	643			(3)
	2012	688			
	2013	708			(4)
	2014	730		1.14	
7. Total AG-Recommended Adjustments			$	10,386,632	
8. AG-Recommended NiSource Costs Allocated to Columbia			$	(2,347,004)	

(1) Schedule D-2.2, Sheet 2 of 3, Adjustment 9
(2) Case 2009-00141, Schedule D-2.8, Sheet 1, line 20 less line 3
(3) CPI values for 2009 and 2012, response to AG 1-139
(4) CPI values for 2013 and 2014, 2012 plus 3% per year

Test Period Ending 12/31/14
Case No. 2013-00167

Sch. FWR-11

COLUMBIA GAS OF KENTUCKY

	Columbia (1)	Adjustment	AG	
Depreciation Expense Adjustment:				
1. Annualized Plant Depreciation	$ 11,548,354	$ (2,829,000)	$ 8,719,354	(2)
2. Annualized CWIP Depreciation	-	-	-	
3. Total Annualized Depreciation	$ 11,548,354	$ (2,829,000)	$ 8,719,354	
Depreciation Reserve Adjustment:				
4. Annualized Depreciation Expense [L3]	$ 11,548,354	$ (2,829,000)	$ 8,719,354	
5. Test Year Per Books Depreciation Exp.	6,962,687		6,962,687	
6. Difference	4,585,667		1,756,667	
7. Pro forma Depreciation Reserve Adjustment	$ -		$ 1,756,667	

(1) Schedules D-2.3, Sheet 2 and D-2.1, Sheet 6
(2) Exhibit FWR-11A

COLUMBIA GAS OF KENTUCKY
DEPRECIATION EXPENSE ADJUSTMENT DETAIL

	Net Salvage (a)	Book Cost ($000) (b)	Allocated Reserve ($000) c)	Future Accruals ($000) (d) = (1-(a))*(b)-c)	R/L e)	Annual Accrual ($000) (f) = (d)/e)	Adjustment ($000)
Lower Net Salvage for Mains							
Depreciation Expense - ELG (1)							
Total Mains	-15%	$ 180,114	$ 54,042	$ 153,089	55	$ 2,776	
Depreciation Expesne - Average Service Life Procedure (2)							
Mains - Cast Iron	-15%	$ 273	$ 260	$ 54	20	$ 3	
Mains - Bare Steel	-15%	$ 17,968	$ 16,608	$ 4,055	21	$ 197	
Mains - Coated Steel	-15%	$ 44,837	$ 12,626	$ 38,937	56	$ 692	
Mains - Plastic	-15%	$ 98,419	$ 22,114	$ 91,068	59	$ 1,541	
Total Mains		$ 161,497	$ 51,608	$ 134,114	55.14	$ 2,432	
Average Service Life With Lower Net Salvage							
Total Mains	-10%	$ 180,114	$ 54,042	$ 144,083	55	$ 2,613	
Adjustment							$ (163)
Lowe Net Salvage for Services							
Depreciation Expense - ELG (1)							
Services	-60%	$ 106,378	$ 57,925	$ 112,280	29.8	$ 3,768	
Depreciation Expense - Average Service Life Procedure (2)							
Services	-60%	$ 95,861	$ 54,739	$ 98,639	29.8	$ 3,310	
Average Service Life With Lower Net Salvage							
Services	-50%	$ 106,378	$ 57,925	$ 101,642	29.8	$ 3,411	
Adjustment							$ (357)
Reject ELG Procedure							
Depreciaiton Expense Using ELG (3)						$ 10,870	
Depreciation Expense Using Braod Group Average Service Life (4)						$ 8,561	
Adjustment							$ (2,309)
Total Depreciation Adjustment							$ (2,829)

(1) Filing Requirment 12-s, pages III 149 - III-153, and III-157
(2) Response to AG question 1-92
(3) Filing Requirment 12-s, page III-5
(4) Response to AG quesiton 1-92

COLUMBIA GAS OF KENTUCKY
INCOME TAXES

	Columbia (1)		Adjustment	AG	
1. Operating Income Before Income Tax	$ 8,305,475		$ 10,140,264	$ 18,445,739	FWR-5
2. Less: Pro Forma Interest Expenses	(5,509,389)			(5,509,389)	
3. Plus: Statutary Adjustments	47,441			47,441	
4. State Taxable Income	2,843,527			12,983,791	
5. State Income Taxes @ 6%	170,612		$ 608,417	779,029	
6. Amortization of Excess State ADIT	(24,898)			(24,898)	
7. Net State Income Taxes	145,714		$ 608,417	754,131	
8. Federal Taxable Income [L4-L5]	2,672,915			12,204,762	
9. Federal Income Taxes	908,791	(2)	$ 3,362,876	4,271,667	(3)
10. Amortization of Excess Federal ADIT	(69,679)			(69,679)	
11. Amortization of Investment Tax Credit	(78,311)			(78,311)	
12. Net Federal Income Taxes	760,801		3,362,876	4,123,677	
13. Total Income Taxes [L7 + L13]	$ 906,515		$ 3,971,293	$ 4,877,808	

(1) Schedule E-1, Sheet 1 of 2
(2) "Stand-alone" federal income tax rate of 34%
(3) Consolidated filing federal income tax rate of 35%

Exhibit FWR -1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY --** Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Study – Atmos Energy – Docket No. 11-UN-184 – On behalf of the Mississippi Public Service Commission, submitted report on reasonableness of Company's depreciation study. 2012

Rate Study – Entergy Mississippi –Docket No. 11-UA-83 -- On behalf of the Mississippi Public Service Commission, prepared report on the reasonableness of Entergy Mississippi's depreciation study. 2012

Rate Case Cost of Service Study – Mississippi Power Company – On behalf of the Mississippi Public Service Commission, prepared report on reasonableness of embedded cost of service study submitted by Mississippi Power Co. 2012

Rate Case Cost of Service Study – Boonville, NY – Prepared class load study and embedded cost of service study to justify change in rate design for the purpose of conserving energy. 2010-2012
Rate Setting – Alliance Energy Transmission - Case No. 12-G-0256 – Prepared rate filing before the New York Public Service Commission for Alliance Energy Transmission. 2012

Rate Setting – Hamilton, NY - Case No. 12-E-0286 - Prepared rate filing before the New York Public Service Commission for the Village of Hamilton, NY to increase its annual electric revenues. 2012

Rate Setting – Fairport, NY – Case No. 11-E-0357 - Prepared rate filing before the New York Public Service Commission for the Village of Fairport, NY to increase its annual electric revenues. 2011

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Analysis – Southwestern Power Company – On behalf of a coalition of retail customers analyzed reasonableness of utility's request to include the costs of Construction Work In Progress Expenditures in rates for a power plant known as the Turk Plant. 2010

Rate Study – Stowe Electric Department, VT – Docket No. 8169 – For small municipal electric utility, filed rate case before the Vermont Public Service Board. 2010

Docket No. 10-10-03 – Assisted in the CT OCC's review and development of recommendations for the Review of the 2011 Conservation and Load Management Plan. 2010

Rate Setting – Endicott, NY - Case No. 10-E-0588 – Prepared rate filing before the New York Public Service Commission for the Village of Endicott, NY to increase its annual electric revenues. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Setting Training – MMWEC – Assisted in training MMWEC staff on rate setting process so that they could provide service to members. 2009

Rate Setting – Connecticut Natural Gas -- Docket No. 08-12-06 - Assisted the Connecticut Office of Consumer Counsel on the analysis of the reasonableness of the of the Company's proposed revenue requirement. 2009

Rate Filing – Heritage Hills Water Works – Case No. 08-W-1201 – Prepared rate filing before the New York PSC for the Heritage Hills Water Works Corporation to increase its annual water revenues. 2008

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation. 2008

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case No. FC 1093 - Washington Gas and Light – On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal to replace and/or remediate certain gas distribution facilities that are subject of this case, 2012.

Docket No. C-2011-2226096 — Pennsylvania American Water Co. - In a class-action lawsuit, testified before the PA PUC on behalf of C. Leslie Pettko on the reasonableness of the surcharges imposed by Pennsylvania American Water Company. 2012

Docket No. 11-06007 – Nevada Power Company – On behalf of the Nevada Public Service Commission, testified on the reasonableness of the Company electric depreciation study on Nevada Power Co. 2011

MEUA –On behalf of the Municipal Electric Utilities Association, filed testimony with the New York Power Authority (NYPA) on the reasonableness of the Authority's 2011 Rate Modification Plan for the Niagara Power Project. 2011

Case No. 9283 – Green Ridge Utilities, Inc. – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2011

Case No. 11-G-0280 – Corning Natural Gas -- On behalf of the Village of Bath, NY, analyzed the construction program, revenue requirement, and rate design proposed by the gas distribution company serving the Village. 2011

Case No. 10-G-0598 – Bath Electric Gas and Water Systems - Testified as to the reasonableness of the Village of Bath's request for a refund relating to overcharges for gas purchased from the Corning Natural Gas Co. 2011

Case No. U-16472 – Detroit Edison -- On behalf of four large hospitals – Detroit Medical Center, Henry Ford Health Systems, William Beaumont Hospital, and Trinity Health Michigan – testified on the reasonableness of the continuation of a service class for large customers with special contracts. 2011

Case No. 9252 – Artesian Water Maryland, Inc. - On behalf of the Maryland Office of People's Counsel, analyzed proposed revenue requirement of Artesian Water Maryland, Inc. 2011.

Case No. 10-E-0362 – Orange and Rockland Utilities, Inc. - On behalf of a coalition of municipalities, testified on the reasonableness of the proposed revenue requirement of Company. 2010.

Docket No. 05-10-RE04 – Connecticut Light and Power Co. – On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the assist in its review of the application of Company for approval of full deployment of its Advance Metering Infrastructure ("AMI"). 2010

Docket Nos. 10-06003 and 10-06004 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2010.

Case No. 10-E-0050 – Niagara Mohawk Power Corporation -- On behalf of a coalition of municipalities, testified on the reasonableness of utility's proposal to eliminate contracts to provide street lighting service. 2010

Case No. 9248 – Maryland Water Services - On behalf of the Maryland Office of the People's Counsel, testified on the reasonableness of the proposed revenue requirement of Maryland Water Services, Inc. 2011

Docket No. 10-12-02 – Yankee Gas Services Company -- On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the Company's proposed depreciation rates. 2010

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel of the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in depreciation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdrola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed \$4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed \$0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Exhibit FWR -2

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
THE APPLICATION OF	)	
KENTUCKY-AMERICAN WATER	)	CASE NO. 2012-000520
COMPANY TO INCREASE	)	
ITS WATER SERVICE RATES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

April 3, 2013

Kentucky-American Water Company
Case No. 2012-000520

Direct Testimony of
Dr. J. Randall Woolridge

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LIST OF EXHIBITS

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge. My business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Kentucky Office of Attorney General ("OAG") to provide an opinion as to the overall fair rate of return or cost of capital for Kentucky American Water Company ("KAWC" or "Company") and to evaluate KAWC's rate of return testimony in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First I will review my cost of capital recommendation for KAWC, and detail the primary areas of contention between KAWC's rate of return position and the OAG's. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss my proxy groups of water utility and gas distribution companies for estimating the cost of capital for KAWC. Fourth, I present my recommendations for the Company's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital and then estimate the equity cost rate for KAWC. Finally, I critique the Company's rate of return analysis and testimony. I have included a table of contents which provides a more detailed outline.

Q. PLEASE REVIEW YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR KAWC.

A. I have employed the Company's proposed capital structure. I have adjusted the Company's short-term and long-term debt cost rates to reflect current market interest rates. I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to two proxy groups of publicly-held water utility ("Water Proxy Group") and gas distribution companies ("Gas Proxy Group"). My analysis indicates an equity cost rate in the range of 7.3% to 8.6%. Within this range, I have used 8.50% as my equity cost rate for KAWC. I provide evidence in my testimony that this recommendation is consistent with the authorized returns on equity ("ROEs") for water companies.

Using my capital structure and debt and equity cost rates, I am recommending an overall rate of return of 7.07% for KAWC. These findings are summarized in Exhibit JRW-1.

Q. PLEASE SUMMARIZE THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The Company's rate of return testimony is offered by Mr. Scott W. Rungren and Dr. James H. Vander Weide. Mr. Rungren provides a recommended capital structure, senior capital cost rates, and overall rate of return. Dr. Vander Weide provides a recommended return on equity. The Company's proposed rate of return is inflated due to overstated debt and equity cost rates. Mr. Rungren short-term debt cost rate is excessive because he has used a projected LIBOR rate that is above current market rates. In his long-term debt cost rate, Mr. Rungen has employed interest rates on pro forma financings that are above current market interest rates.

Dr. James A. Vander Weide provides the Company's equity cost rate. Dr. Vander Weide's estimated common equity cost rate is in the range of 10.4% - 11.4%. Within this range, the Company has requested an equity cost rate of 10.9%. We have both used DCF and CAPM approaches in estimating an equity cost rate for the Company. Dr. Vander Weide has also used a Risk Premium ("RP") approach to estimate an equity cost rate for KAWC. Dr. Vander Weide has applied these approaches to proxy groups of water utility and gas distribution companies.

In terms of the DCF approach, the two major areas of disagreement are (1) the appropriate adjustment to the DCF dividend yield and (2) most significantly, the estimation of the expected growth rate. With respect to the dividend yield adjustment, Dr. Vander Weide has made an inappropriate adjustment to reflect the quarterly payment of dividends. For a DCF growth rate, Dr. Vander Weide has relied exclusively on the forecasted earnings per share ("EPS") growth rates of Wall Street analysts and *Value Line*. I provide empirical evidence from new studies that demonstrate the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased. I also show that the estimated long-term EPS growth rates of *Value Line* are overstated. Consequently, in developing a DCF growth rate, I have used both historic and projected growth rate measures and have evaluated growth in dividends, book value, and earnings per share.

The RP and CAPM approaches require an estimate of the base interest rate and the market or equity risk premium. In both approaches, Dr. Vander Weide's base interest rate is above current market rates. However, the major area of disagreement involves our significantly different views on the alternative approaches to measuring the market risk premium as well as the magnitude of equity risk premium. Dr. Vander Weide's market risk premiums are excessive and do not reflect current market fundamentals. As I highlight in my testimony, there are three procedures for estimating a market risk premium – historic returns, surveys, and expected return models. Dr. Vander Weide uses a historical market risk premium which is based on historic stock and bond returns. He also calculates an expected market risk premium in which he applies the DCF approach to the S&P 500 and public utility stocks. I provide evidence that risk premiums based on historic stock and bond returns are subject to empirical errors which result in upwardly biased measures of expected market risk premiums. I also demonstrate that Dr. Vander Weide's projected market risk premium, which uses analysts' EPS growth rate projections, includes unrealistic assumptions regarding future economic and earnings growth and stock returns. In addition, Dr. Vander Weide makes an unwarranted adjustment to his equity cost rate estimates for flotation costs which inflate his equity cost rate estimates.

In the end, the most significant areas of disagreement in measuring KAWC's cost of capital are: (1) the appropriate short-term and long-term debt cost rates; (3) the use of the earnings per share growth rates of Wall Street analysts and *Value Line* to measure expected DCF growth; (4) the base interest rate in the CAPM and RP approaches; (5) the measurement and magnitude of the market risk premium used in CAPM and RP approaches; and (6) whether or not equity cost rate adjustments are needed to account for flotation costs.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN U.S. MARKETS.

A. Long-term capital cost rates for U.S. corporations are a function of the required returns on risk-free securities plus a risk premium. The risk-free rate of interest is the yield on long-term U.S Treasury yields. The yields on ten-year U.S. Treasury bonds from 1953 to the present are provided on page 1 of Exhibit JRW-2. These yields peaked in the early 1980s and have generally declined since that time. These yields have fallen to historically low levels in recent years due to the financial crisis. In 2008 Treasury yields declined to below 3.0% as a result of the mortgage and subprime market credit crisis, the turmoil in the financial sector, the monetary stimulus provided by the Federal Reserve, and the slowdown in the economy. From 2008 until 2011, these rates fluctuated between 2.5% and 3.5%. Over the past year, the yields on ten-year Treasuries have declined from 2.5% to below 2.0% as the Federal Reserve has continued to support a low interest rate environment and economic uncertainties have persisted.

Panel B on Exhibit JRW-2 shows the differences in yields between ten-year Treasuries and Moody's Baa rated bonds since the year 2000. This differential primarily reflects the additional risk required by bond investors for the risk associated with investing in corporate bonds. The difference also reflects, to some degree, yield curve changes over time. The Baa rating is the lowest of the investment grade bond ratings for corporate bonds. The yield differential hovered in the 2.0% to 3.5% range until 2005, declined to 1.5% until late 2007, and then increased significantly in response to the financial crisis. This differential peaked at 6.0% at the height of the financial crisis in early 2009, due to tightening in credit markets, which increased corporate bond yields and the "flight to quality," which decreased treasury yields. The differential subsequently declined and has been in the 2.5% to 3.5% range over the past three years.

As previously noted, the risk premium is the return premium required by investors to purchase riskier securities. The risk premium required by investors to buy corporate bonds is observable based on yield differentials in the markets. The market risk premium is the return premium required to purchase stocks as opposed to bonds. The market or equity risk premium is not readily observable in the markets (as are bond risk premiums) since expected stock market returns are not readily observable. As a result, equity risk premiums must be estimated using market data. There are alternative methodologies to estimate the equity risk premium, and these alternative approaches and equity risk premium results are subject to much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5% to 7% range. However, studies by leading academics indicate the forward-looking equity risk premium is actually in the 4.0% to 5.0% range. These lower equity risk premium results are in line with the findings of equity risk premium surveys of CFOs, academics, analysts, companies, and financial forecasters.

Q. PLEASE DISCUSS INTEREST RATES AND THE FINANCIAL

CRISIS.

A. The yields on Treasury securities decreased significantly at the onset of the financial crisis and have remained at historically low levels. In fact, these yields have declined to levels not seen since the 1940s. The decline in interest rates reflects several factors, including: (1) the "flight to quality" in the credit markets as investors sought out low risk investments during the financial crisis; (2) the very aggressive monetary actions of the Federal Reserve, which have been aimed at restoring liquidity and faith in the financial system as well as maintaining low interest rates to boost economic growth; and (3) the continuing slow recovery from the recession.

The credit market for corporate and utility debt experienced higher rates due to the credit crisis. The long-term corporate credit markets tightened during the financial crisis, but have improved significantly since 2009. Interest rates on utility and corporate debt have declined to historically low levels. These low rates reflect the monetary policy actions of the Federal Reserve and the weak economy.

Panel A of page 1 of Exhibit JRW-3 provides the yields on 'A' rated public utility bonds. These yields peaked in November 2008 at 7.75% and have since declined to about 4.2% as of February 2013. Panel B of page 1 of Exhibit JRW-3 provides the yield spreads between long-term 'A' rated public utility bonds relative to the yields on 20-year Treasury bonds. These yield spreads increased dramatically in the third quarter of 2008 during the peak of the financial crisis and have decreased significantly since that time. For example, the yield spreads between 20-year U.S. Treasury bonds and 'A' rated utility bonds peaked at 3.40% in November of 2008, declined to about 1.5% in the summer of 2012, and have since remained in that range.

In sum, while the economy continues to face significant problems, the actions of the government and Federal Reserve had a large effect on the credit markets. The capital costs for utilities, as measured by the yields on 30-year utility bonds, have declined to historically low levels.

Q. ARE INTEREST RATES LIKELY TO REMAIN LOW FOR SOME TIME?

A. Yes. On September 13, 2012, the Federal Reserve released its policy statement relating to Quantitative Easing III ("QE3"). In the statement, the Federal Reserve announced the following:[1]

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee agreed today to increase policy accommodation by purchasing additional agency mortgage-backed securities at a pace of $40 billion per month. The Committee also will continue through the end of the year its program to extend the average maturity of its holdings of securities as announced in June, and it is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities. These actions, which together will increase the Committee's holdings of longer-term securities by about $85 billion each month through the end of the year, should put downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

[1] Board of Governors of the Federal Reserve System, "Statement Regarding Transactions in Agency Mortgage-Backed Securities and Treasury Securities," September 13, 2012.

The Federal Reserve also indicated that it intends to keep the target rate for the federal funds rate between 0 to ¼ percent through at least mid-2015. These monetary policy actions of the Federal Reserve, coupled with U.S. economic conditions of slow economic growth, high unemployment, and low inflation, should keep U.S. interest rates and capital costs low for several years. The likelihood that these conditions will keep interest rates and capital costs low for U.S. businesses is reinforced by the economic and political problems in Europe, as the U.S. is viewed as a safe haven for investment capital around the world.

Q. PLEASE ALSO DISCUSS THE FED'S DECEMBER 12, 2012 PRESS RELEASE REGARDING AN EXPANSION OF THE QE3 PROGRAM.

A. On December 12, 2012, the Federal Reserve expanded its bond buying program and tied future monetary policy moves to unemployment rates and the level of interest rates. In the release, the Federal Reserve Board indicated the following:[2]

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee remains concerned that, without sufficient policy accommodation, economic growth might not be strong enough to generate sustained improvement in labor market conditions. Furthermore, strains in global financial markets continue to pose significant downside risks to the economic outlook. The Committee also anticipates that inflation over the medium term likely will run at or below its 2 percent objective.
>
> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee will continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month. The Committee also will purchase longer-term Treasury securities after its program to extend the average maturity of its

[2] Board of Governors of the Federal Reserve System, FOMC Statement," December 12, 2012.

> holdings of Treasury securities is completed at the end of the year, initially at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and, in January, will resume rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

With respect to tying monetary policy to interest rates and unemployment, the Fed indicated the following:

> In particular, the Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment rate remains above 6-1/2 percent, inflation between one and two years ahead is projected to be no more than a half percentage point above the Committee's 2 percent longer-run goal, and longer-term inflation expectations continue to be well anchored. The Committee views these thresholds as consistent with its earlier date-based guidance.

Q. HAS THE FEDERAL RESERVE BOARD RECENTLY UPDATED ITS STANCE ON MONETARY POLICY AND INTEREST RATES?

A. Yes. In the March 20, 2013 Federal Open Market Committee ("FOMC") meeting, the Federal Reserve voted to continue its bond buying program policy and stick with its plan to keep interest rates at historically low levels until unemployment falls to 6.5 percent. In its policy statement, the Federal Reserve acknowledged that the U.S. job market has improved, and that consumer spending and business investment have increased and the housing market has improved. However, the Fed also said it still did not expect unemployment to reach 6.5 percent until 2015.

Q. HOW DO THE CAPITAL COST INDICATORS COMPARE TODAY TO THOSE AT THE TIME OF KAWC'S LAST RATE CASE (CASE NO. 2010-00036)?

A. On page 2 of Exhibit JRW-3, I provide the yields on ten-year Treasury bonds and thirty-year, A-rated utility bonds for the six month periods – March, 2010 to August, 2010, and August 2012 to January 2013. Current interest rates and capital costs are below those at the time of Case No 2010-00036. Panel A of Exhibit JRW-3 shows the yields on ten-year Treasury bonds. The average ten-year Treasury yields for these two periods are 3.32% and 1.74%, respectively. Panel B of page 2 of Exhibit JRW-3 shows the yields on thirty-year, A-rated public utility bonds for the same six month periods. The average yields for these periods are 5.48% and 3.99%, respectively. These yields also indicate a decline in utility capital costs. In both cases, the decline in interest rates and capital costs is about 150 basis points.

Q. OVERALL, WHAT DOES YOUR REVIEW OF THE CAPITAL MARKET CONDITIONS INDICATE ABOUT THE EQUITY COST RATE FOR UTILITIES TODAY.

A. The market data suggests that capital costs for utilities are at historically low levels and are likely to stay low for some time. As shown on page 1 of Exhibit JRW-3, the yield on long-term 'A' rated utility bonds is about 4.2%. In addition, utility bond yields and capital costs are about 150 basis points below their levels at the time of KAWC's last rate case in 2010. As demonstrated later in my testimony, these lower capital costs are also indicated by the DCF and CAPM data for water utility and gas distribution companies.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR KAWC.

A. To develop a fair rate of return recommendation for KAWC, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held water utility companies ("Water Proxy Group") and a proxy group of publicly-held gas distribution companies ("Gas Proxy Group").

Q. WHY HAVE YOU EMPLOYED THE RESULTS FOR A PROXY GROUP OF GAS DISTRIBUTION COMPANIES IN YOUR TESTIMONY?

A. I have included an analysis of the results for the Gas Proxy Group in my testimony. I have included these results for two reasons. First, the financial data needed to perform a DCF analysis for the Water Proxy Group is limited. Analysts' coverage of the water companies very is sparse. On the other hand, there is better data available for the Gas Proxy Group to perform a DCF equity cost rate study. Second, the return requirements of investors on gas companies should be similar to that of water companies. Both industries are capital intensive and heavily regulated and provide for the distribution and delivery of an essential commodity whose service rates and rates of return are set by state regulatory commissions. It should be highlighted, however, that gas distribution companies do face the risk of substitution whereas water companies do not.

Q. PLEASE DESCRIBE YOUR TWO PROXY GROUPS.

A. My Water Proxy Group consists of nine water utility companies that are covered by the *Value Line Investment Survey* and *AUS Utility Reports*. These companies include American States Water Company, American Water Works Company, Aqua American, Inc., Artesian Resources Corporation, California Water Service Group, Connecticut Water Service, Inc., Middlesex Water Company, SJW Corporation, and York Water Company. A summary of financial statistics for the companies in this group are listed in Exhibit JRW-4. The median operating revenues and net plant for the Water Proxy Group are $261.4M and $870.5M, respectively.[3] The group receives 96% of revenues from regulated water operations, has an 'A' bond rating, a common equity ratio of 46.5%, and an earned return on common equity of 9.8%.

My Gas Proxy Group proxy group consists of eight natural gas distribution companies. These companies meet the following selection criteria: (1) listed as a Natural Gas Distribution, Transmission, and/or Integrated Gas Companies in *AUS Utility Reports*; (2) listed as a Natural Gas Utility in the Standard Edition of the *Value Line Investment Survey*; and (3) an investment grade bond rating by Moody's and Standard & Poor's. As shown on page 1 of Exhibit JRW-4, the companies meeting these criteria include AGL Resources,

[3] In my testimony, I present financial results using both mean and medians as measures of central tendency. However, due to outliers, I have used the median as a measure of central tendency.

Atmos Energy Corporation, Laclede Group, Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. The only companies that met these criteria and were not included in the group were New Jersey Resources and UGI. These companies were excluded due to their low percentage of revenues from regulated gas operations. Summary financial statistics for the proxy group are listed on page 1 of Exhibit JRW-4. The median operating revenues and net plant for the Gas Proxy Group are $1,545.2M and $2,802.0M, respectively. The group receives 69% of revenues from regulated gas operations, has an 'A2/A3' Moody's bond rating and an 'A/A-' bond rating from Standard & Poor's, a current common equity ratio of 47.7%, and an earned return on common equity of 10.5%.

On page 2 of Exhibit JRW-4, I have assessed the riskiness of the two groups using five different risk measures published by *Value Line*. These measures include Beta, Safety, Financial Strength, Earnings Predictability, and Stock Price Stability. All five of the risk measures suggest that the Gas Proxy Group is less risky than the Water Proxy Group. However, the magnitude of the differences in the risk metrics is not large. Nonetheless, these *Value Line* measures do suggest that that the Gas Proxy Group is a little less risky than the Water Proxy Group.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT CAPITAL STRUCTURE RATIOS HAVE BEEN PROPOSED BY THE COMPANY?

A. Mr. Rungren provides KAWC's proposed capital structure which is a 13-month average. As shown in Panel A of page 1 of Exhibit JRW-5, this capital structure consists of 2.041% short-term debt, 52.037% long-term debt, 1.1168% preferred stock, and 44.754% common equity. He employs short-term and long-term debt cost rates of 0.81% and 6.14% and a preferred stock cost rate of 8.52%.

Q. ARE YOU EMPLOYING KAWC'S PROPOSED CAPITAL STRUCTURE IN DETERMINING YOUR OVERALL RATE OF RETURN?

A. Yes.

Q. WHAT SENIOR CAPITAL COST RATES ARE YOU EMPLOYING?

A. The Company's proposed short-term debt cost rate is based on a projected 1-month LIBOR rate plus a 0.25% borrowing spread to LIBOR. As shown in Panel A of page 2 of Exhibit JRW-5, the current 1-month and 3-month LIBOR rates are 0.20% and 0.28%. Hence, I will use a current LIBOR rate 0.25% plus the borrowing spread to LIBOR of 0.25% for a short-term debt cost rate of 0.50%.

I have used a long-term debt cost rate of 6.05%. This is the long-term debt cost rate computed by the Company in response to Staff 2-45. The calculation is provided in Panel B of page 2 of Exhibit JRW-5. In its recommendation, KAWC had used a projected interest rate on 2013 and 2014 debt issuances of 5.20%. However, on December 17, 2012, American Water Works sold $300 million of senior unsecured notes with a yield of 4.30%. The 6.05% overall long-term debt cost rate uses this 4.30% rate on the 2013 and 2014 debt issuances.

I have employed the Company's recommended 8.52% for preferred stock.

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, are sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[4]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically

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[4] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

> profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[5]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

[5] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries that are covered by *Value Line* and have estimated return on equity and market-to-book ratio data. The results are presented in Panels A-C of Exhibit JRW-6. The average R-squares for the electric, gas, and water companies are 0.52, 0.71, and 0.77, respectively.[6] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-7 provides indicators of public utility equity cost rates over the past decade.

Page 1 shows the yields on long-term A-rated rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. These yields spiked up to the 7.5% range with onset of the financial crisis, and remained high and volatile until early 2009. These yields have declined since that time from the 6.0% range to the 4.2% range as of February, 2013.

[6] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

Page 2 provides the dividend yields for the Water and Gas Proxy Groups over the past decade. The dividend yields for both groups have declined slightly over the decade. The Water Proxy Group yields bottomed out at 2.75% in 2006, increased to 3.7% in 2009, and have since declined to 3.4%. The Gas Proxy Group yields bottomed out at 3.75% in 2007, increased to 4.2% in 2009, and have since declined to 3.8%.

Average earned returns on common equity and market-to-book ratios for the two groups are on page 3 of Exhibit JRW-7. For the Water Proxy Group, earned returns on common equity peaked early in the decade at almost 10.5%. Over the past five years, they have been in the 8.0% to 9.0% range. As of 2011, the average ROE for the group was just over 8.0%. The average market-to-book ratios for this group have ranged from 1.5X to 2.3X. As of 2011, the market-to-book average was about 1.75X. For the Gas Proxy Group, earned returns on common equity have been in the 10.0% to 12.0% range. The average ROE as of 2011 was 10.0%. Over the past decade, the average market-to-book ratios for this group have ranged from 1.50X to 1.80X.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-8 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey* and are compiled annually by Aswath Damodoran of New York University.[7] The study shows that the investment risk of utilities is very low. The average beta for electric, water, and gas

[7] *Available* at http://www.stern.nyu.edu/~adamodar.

utility companies are 0.73, 0.66, and 0.66, respectively. These are well below the *Value Line* average of 1.15. As such, the cost of equity for utilities is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my experience that this Commission has traditionally relied on the DCF method. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \cdots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-9. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the

DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT JRW-10.

A. My DCF analysis is provided in Exhibit JRW-10. The DCF summary is on page 1 of this Exhibit, and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages of the Exhibit.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR THE PROXY GROUPS?

A. The dividend yields on the common stock for the companies in the proxy groups are provided on page 2 of Exhibit JRW-10 for the six-month period ending March 2013. For the DCF dividend yields for the group, I am using the average of the median six month and March 2013 dividend yields. The table below shows these dividend yields.

	March 2013 Dividend Yield	6-Month Median Dividend Yield	DCF Dividend Yield
Water Proxy Group	**2.9%**	**3.1%**	**3.0%**
Gas Proxy Group	**3.8%**	**3.9%**	**3.9%**

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[8]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year

[8] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by one-half (1/2) the expected growth so as to reflect growth over the coming year. This is the approach employed by the Federal Energy Regulatory Commission ("FERC").[9] The DCF equity cost rate ("K") is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

[9] Opinion No. 414-A, *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶61,084 (1998).

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the actual analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecasts data free-of-charge on the internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zack's estimates are also available on other websites, such as msn.money (http://money.msn.com).

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the EPS forecasts compiled by Reuters for American States Water Co. (stock symbol "AWR").

Consensus Earnings Estimates
American States Water Co. **(AWR)**
www.reuters.com
March 7, 2012

	# of Estimates	Mean	High	Low
Earnings (per share)				
Quarter Ending Mar-13	5	0.54	0.59	0.49
Quarter Ending Jun-13	5	0.79	0.85	0.66
Year Ending Dec-13	6	2.68	2.80	2.55
Year Ending Dec-14	3	2.68	2.75	2.55
LT Growth Rate (%)	1	6.00	6.00	6.00

These figures can be interpreted as follows. The top line shows that five analysts have provided EPS estimates for the quarter ending March 31, 2013. The mean, high and low estimates are $0.54, $0.59, and $0.49, respectively. The second line shows the quarterly EPS estimates for the quarter ending June 30, 2013. Lines three and four show the annual EPS estimates for the fiscal years ending December 2013 and 2014. The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. As in the AWR case shown here, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line shows the projected long-term EPS growth rate which is expressed as a percentage. For AWR, one analyst has provided long-term EPS growth rate forecasts, with mean, high and low growth rates of 6.00%.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. WHY ARE YOU NOT RELYING EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUPS?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[10] Employing data over a twenty year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. This issue is discussed at length in Appendix B of this testimony. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate.

[10] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[11]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth rate forecasts, and therefore, stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Since stock prices reflect the bias, it would affect the dividend yield. In addition, the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS AS PROVIDED BY *VALUE LINE*.

A. Page 3 of Exhibit JRW-10 provides the 5- and 10- year historical growth rates for the companies in the groups, as published in the *Value Line Investment Survey*. The historical growth measures in EPS, DPS, and BVPS for the

[11] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

Water Proxy Group, as measured by the medians, range from 2.0% to 5.3%, with an average of 3.9%. For the Gas Proxy Group, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 2.5% to 5.5%, with an average of 4.3%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-10. As previous indicated, due to the presence of outliers, the medians are used in the analysis. For the Water Proxy Group, the medians range from 3.0% to 7.0%, with an average of 4.5%. For the Gas Proxy Group, the medians range from 2.8% to 5.5%, with an average of 4.4%.

Also provided on page 4 of Exhibit JRW-10 is prospective sustainable growth for the proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is significant and a primary driver of long-run earnings growth. For the Water Proxy Group, the median prospective sustainable growth rate is 4.4%. The median prospective sustainable growth rate for the Gas Proxy Group is 4.4%.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' long-term EPS growth rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-10. The median of analysts' projected EPS growth rates for the Water Proxy Group is 6.0%.[12] The median of analysts' projected EPS growth rates for the Gas Proxy Group is 4.6%.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-10 shows the summary DCF growth rate indicators for the proxy groups. The data for the Gas Proxy Group are more complete and provide a better indication of expected growth and the DCF equity cost rate. *Value Line* only has projections for seven of the companies in the Water Proxy Group, and analysts' EPS growth rate forecasts are limited and highly variable.

The historical growth rate indicators for the Water Proxy Group imply a baseline growth rate in the range of 3.9%. The high end of the range for the Water Proxy Group is 6.0% which is the projected EPS growth rates of Wall

[12] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

Street analysts. However, the projected growth rate indicators for the Water Proxy Group are limited in number and variable. The average of the historic, sustainable, and projected growth rate indicators is 4.7%, and the average of the sustainable and projected EPS growth rates is 5.0%. As indicated, analysts' projected EPS growth for the companies in the Water Proxy Group is 6.0%. Focusing primarily on the sustainable and projected growth rate measures, I believe that an expected growth rate in the 5.0% to 6.0% range is appropriate for the Water Proxy Group. Given these figures, I will use the mid-point of this range, 5.5%, as the DCF growth rate for the Water Proxy Group.

The historical growth rate figures for the Gas Proxy Group suggest a baseline growth rate of 4.3% for these companies. The projected and sustainable growth rates from *Value Line* are 4.4% and 4.4% for the group. Analysts projected EPS growth is 4.6%. The average of sustainable and projected EPS growth rate indicators is 4.4%. Giving more weight to the projected growth rate figures, I will use the 4.5% as the DCF growth rate for the Water Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE GROUPS?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-10.

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Water Proxy Group	**3.0%**	**1.02750**	**5.50%**	**8.60%**
Gas Proxy Group	**3.9%**	**1.02250**	**4.50%**	**8.50%**

C. Capital Asset Pricing Model Results

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + \text{ß} * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-11.

A. Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. The yield on 30-year Treasury bonds has been in the 2.5% to 4.0% range over 2011 – 2013 time period. These rates are currently in the middle of this range. Given the recent range of yields, and the prospect of higher rates in the future, I will use 4.0%, as the risk-free rate, or R_f, in my CAPM.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which the ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy group, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median beta for the companies in the Water and Gas Proxy Groups are 0.70 and 0.65,respectively.

Q. PLEASE DISCUSS THE ALTERNATIVE VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium - $(E(R_m) - R_f)$ - is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 $(E(R_m)$ minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. Page 4 of Exhibit JRW-11 highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies.[13] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[14]

In addition, there are a number of surveys of financial professionals regarding the equity risk premium. There have been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs which includes questions regarding their views on the current expected returns on stocks and bonds. Usually over 500 CFOs participate in the survey.[15] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters which is published as the *Survey of Professional Forecasters*.[16] This survey of professional economists has been

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[13] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

[14] Rajnish Mehra & Edward C. Prescott, *The Equity Premium: A Puzzle*, J. MONETARY ECON. 145 (1985).

[15] *See*, www.cfosurvey.org.

[16] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, (February 15, 2013). The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation

published for almost 50 years. In addition, Pablo Fernandez conducts occasional surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[17]

Q. PLEASE PROVIDE A SUMMARY OF THE EQUITY RISK PREMIUM STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the equity risk premium.[18] Derrig and Orr's study evaluated the various approaches to estimating equity risk premiums as well as the issues with the alternative approaches and summarized the findings of the published research on the equity risk premium. Fernandez examined four alternative measures of the equity risk premium – historical, expected, required, and implied. He also reviewed the major studies of the equity risk premium and presented the summary equity risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the equity risk summary.

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with the NBER, assumed responsibility for the survey in June 1990.

[17] Pablo Fernandez, Javier Auirreamalloa, and Javier Corres, "Market Risk Premium Used in 82 Countries in 2012: A survey with 7,192 Answers," June 19, 2012.

[18] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

Page 5 of Exhibit JRW-11 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the equity risk premium. In developing page 5 of Exhibit JRW-11, I have categorized the studies as discussed on page 4 of Exhibit JRW-11. I have also included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed, which is presented in Appendix C. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. **PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-11.**

A. Page 5 of JRW-11 provides a summary of the results of the equity risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* equity risk premium studies, (3) equity risk premium surveys of CFOs, Financial Forecasters, analysts, companies and academics, and (4) the Building Block approaches to the equity risk premium. There are results reported for over thirty studies and the median equity risk premium is 4.93%.

Q. **PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS?**

A. The studies cited on page 5 of Exhibit JRW-11 include all equity risk premium studies and surveys I could identify that were published over the past decade and that provided an equity risk premium estimate. Most of these studies were published prior to the financial crisis of the past two years. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so they were not estimating an equity risk premium as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the equity risk premium, on page 6 of Exhibit JRW-11, I have reconstructed page 5 of Exhibit JRW-11, but I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 4.83%.

Q. GIVEN THESE RESULTS, WHAT MARKET OR EQUITY RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. Much of the data indicates that the market risk premium is in the 4.5% to 5.5% range. I use the midpoint of this range, 5.0%, as the market or equity risk premium.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CFOS?

A. Yes. In the March 31, 2013 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 4.5%.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on Panels D and E of page 2 of Exhibit JRW-C1, the median long-term expected stock and bond returns were 6.13% and 3.83%, respectively. This provides an *ex ante* equity risk premium of 2.30% (6.13%-3.83%).

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF FINANCIAL ANALYSTS AND COMPANIES?

A. Yes. Pablo Fernandez recently published the results of a 2012 survey of financial analysts and companies.[19] This survey included over 7,000 responses. The median equity risk premium employed by U.S. analysts and companies was 5.0% and 5.5%, respectively.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. It published a study entitled "The Real Cost of

[19] Pablo Fernandez, Javier Auirreamalloa, and Javier Corres, "Market Risk Premium Used in 82 Countries in 2012: A survey with 7,192 Answers," June 19, 2012.

Equity" in which the McKinsey authors developed an *ex ante* equity risk premium for the U.S. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[20]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are provided below:

$$K = (R_f) + \beta * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Water Proxy Group	**4.00%**	**0.70**	**5.0%**	**7.5%**
Gas Proxy Group	**4.00%**	**0.65**	**5.0%**	**7.3%**

These results are summarized on page 1 of Exhibit JRW-11.

VI. EQUITY COST RATE SUMMARY

[20] Marc H. Goedhart, *et al.*, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the proxy group of gas distribution are indicated below:

	DCF	CAPM
Water Proxy Group	**8.6%**	**7.5%**
Gas Proxy Group	**8.5%**	**7.3%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. Given these results, I conclude that the appropriate equity cost rate for the Water and Gas Proxy Groups is in the 7.3% to 8.6% range. However, since I given greater weight to the DCF model, I am using an equity cost rate in the upper end of this range. Therefore, I conclude that the appropriate equity cost rate is 8.5%.

Q. WHY DO YOU BELIEVE THAT THE DCF RESULTS FOR THE GAS PROXY GROUP PROVIDE A BENCHMARK AS TO THE TO THE EQUITY COST RATE FOR WATER COMPANIES?

A. I do believe that the equity cost rate results for the gas companies provide an indicator as to the appropriate equity cost rate for water companies. As noted above, the data for the Water Proxy Group are limited. In particular, there are very few analysts who cover the water companies. Also, the projected EPS growth rates for the companies in the Water Proxy Group are variable are questionable in some cases. In addition, as I highlight in my testimony, it is well known that the long-term projected EPS growth rates of Wall Street analysts are overly optimistic and upwardly biased. As a result, the DCF equity cost rate for the Water Proxy Group is dependent on the projected EPS growth rates of a few Wall Street analysts who have a tendency to be optimistic in their forecasts.

Q. DO YOU HAVE ANY OTHER THOUGHTS ON WHY AN 8.50% RETURN ON EQUITY IS APPROPRIATE AT THIS TIME?

A. Yes. There are several reasons why an 8.50% return on equity is appropriate for KAWC in this case. First, as shown on in Exhibit JRW-8, the water utility is the lowest risk industry as ranked by Beta in *Value Line*. As such, water companies have the lowest cost of equity capital of any industry in the U.S. according to the CAPM. Second, as shown in Exhibit JRW-3, capital costs for utilities, as indicated by long-term bond yields, have declined to historically low levels. The current yield on 30-year, A rated utility bonds is about 4.0%. Finally, while the financial markets have recovered over the past four years, the economy has not. The economic times are viewed as being difficult, with almost eight percent unemployment. With the weak economy, interest rates and inflation are at low levels, and hence the expected returns on financial assets – from savings accounts to Treasury Bonds to common stocks – are low. Therefore, in my opinion, an 8.50% return is a very fair and reasonable for a regulated water utility company.

Q. DO YOU BELIEVE THAT YOUR 8.50% RECOMMENDATION IS CONSISTENT WITH THE AUTHORIZED RETURNS ON EQUITY FOR WATER COMPANIES?

A. Yes. Page 1 of Exhibit JRW-12 provides the most recent authorized ROEs for the publicly-traded water companies as reported by *AUS Utilities Reports*. The range of the authorized ROEs is 9.61% to 10.33%, and the average is 9.98%. Given that a number of these reported authorized ROEs are dated, and the lower capital costs indicated by the lower yields on utility bonds (see page 1 of Exhibit JRW-3, I believe that my 8.50% ROE recommendation is consistent with the reported authorized ROEs for water companies.

Q. PLEASE DISCUSS YOUR STUDY OF EARNED VERSUS AUTHORIZED ROES FOR WATER COMPANIES.

A. Page 2 of Exhibit JRW-12 provides the results of my study of the authorized and earned ROEs for publicly-traded water utility companies and their associated market-to-book ratios over the past decade. Panel A provides the annual data, and the data are presented graphically on Panel B. The average authorized ROE was 10.63% in 2002, and has consistently declined over the past ten years. As of 2011, this figure was 9.98%. Earned ROEs have also declined over the decade, and have been below authorized ROEs for nine of the past ten years. On average, earned ROEs have been about 100 basis points below authorized ROEs. As of 2011, the average earned ROE was 8.47%.

Q. HAVE THESE RETURNS BEEN ADEQUATE TO MEET INVESTOR RETURN REQUIREMENTS?

A. Yes. I have also provided the average annual market-to-book ratios for publicly-traded water utility companies as well as the authorized and earned ROEs on page 2 of Exhibit JRW-12. The annual market-to-book ratios have declined over the decade, but with considerable variability. The peak was 2.59X in 2006. In the past three years, the average annual market-to-book ratios for publicly-traded water utility companies have been in the 1.80X to 1.90X range. Overall, the market-to-book ratios for publicly-traded water utility companies data indicate that the earned ROEs have been more than adequate to meet investors' return requirements. It is also noteworthy that the market-to-book ratios for publicly-traded water utility companies have been above the market-to-book ratios for gas distribution and electric utility companies.

Q. PLEASE DISCUSS THE PERFORMANCE OF KAWC RELATIVE TO YOUR WATER PROXY GROUP.

A. On page 3 of Exhibit JRW-12, I have plotted the earned ROEs for KAWC and the average of the Water Proxy Group for the five years 2007-2011. These results suggest that KAWC have been earning higher ROEs than the average of the group in recent years.

Q. FINALLY, DOES THE SMALL SIZE OF KAWC SUGGEST THAT THE COMPANY IS RISKIER?

A. No, not necessarily. Standard & Poor's released a report and addressed the issue of water company size and risk. The Standard & Poor's publication indicated the following.[21]

> "Our criteria revision reflects our view that for general obligation ratings, a small and/or rural issuer does not necessarily have what we consider weaker credit quality than a larger or more-urban issuer. Although we assess these factors in our credit analysis for some revenue bond ratings, we believe many municipal systems still exhibit, in our view, strong and stable credit quality despite size or location constraints. While we believe that smaller or rural utility systems may not necessarily benefit from the economies of scale that can lead to more-efficient operations or lower costs, in our view, they can still have affordable rates, even in places with less-than-favorable household income and wealth levels."

VI. CRITIQUE OF KAWC'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE KAWC'S RATE OF RETURN REQUEST FOR KAWC.

A. KAWC's cost of capital recommendation is provided on page 1 of Exhibit JRW-13. The company is requesting a capital structure from investor sources consisting of 2.04% short-term debt, 52.04% long-term debt, 1.17% preferred stock, and 44.75% common equity. The Company uses short-term debt, long-term debt and preferred stock cost rates of 0.81%, 6.14%, and 8.52% and an equity cost rate of 10.90%.

[21] Standard & Poor's, "26 Weste Water and Sewer Issuers are Upgraded on Revised Criteria," January 12, 2009.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF CAPITAL POSITION?

A. I have issues with the Company's short-term and long-term debt cost rates, and most significantly, the equity cost rate. The debt cost rates were previously discussed. I will focus below on Dr. Vander Weide's equity cost rate of 10.9%.

A. <u>Equity Cost Rate</u>

Q. PLEASE REVIEW DR. VANDER WEIDE'S EQUITY COST RATE APPROACHES.

A. Dr. Vander Weide estimates an equity cost rate for KAWC using the results for two proxy groups and employs DCF, RP, and CAPM equity cost rate approaches.

Q. PLEASE SUMMARIZE DR. VANDER WEIDE'S EQUITY COST RATE RESULTS.

A. Dr. Vander Weide's equity cost rate estimates for KAWC are summarized in Panel A of page 2 of Exhibit JRW-13. Based on these figures, he concludes that the appropriate equity cost rate is in the range of 10.4% to 11.4%. The Company has used 10.9% as an equity cost rate in its rate filing.

Q. PLEASE DISCUSS YOUR ISSUES WITH DR. VANDER WEIDE'S REQUESTED EQUITY COST RATE.

A. Dr. Vander Weide's requested return on common equity is too high primarily due to: (1) the exclusion of some water companies in his water group, and the inclusion of one inappropriate company in his gas group; (2) an excessive adjustment to the dividend yield in his DCF approach; (3) an inflated growth rate in his DCF approach; (4) the use of market-value weights in his DCF equity cost rate analysis; (5) excessive base interest rates and market risk premiums in his RP and CAPM approaches; (6) he has ignored his CAPM equity cost rate results; and (7) unwarranted flotation cost adjustments to his equity cost rate results.

1. Proxy Groups

Q. PLEASE REVIEW DR. VANDER WEIDE'S WATER GROUP.

A. Dr. Vander Weide has used a group of six water companies and a proxy group of seven gas distribution companies. All of the companies in his water group are also in my Water Proxy Group. He has not included Artesian Resources Corp., Connecticut Water Service Group, or York Water Company.

Q. DO YOU BELIEVE THAT DR. VANDER WEIDE'S HAS ERRED IN EXCLUDING THOSE THREE WATER COMPANIES?

A. Yes, for two reasons. First, I believe that a proxy group of only six companies is on the small side to estimate an equity cost rate. Second, and more significantly, he has excluded the three smallest water companies. Given the small size of KAWC, I believe that these three companies should be included in a proxy group of water companies.

Q. PLEASE EVALUATE DR. VANDER WEIDE'S GAS GROUP.

A. Dr. Vander Weide has also used a proxy group of seven gas distribution companies. Six of these companies are included in my Gas Proxy Group. However, I disagree with his inclusion of the other company in group, NiSource. NiSource ("NI") has a riskier operating and financial profile than gas distribution companies. NI receives 28% of revenues from electric utility operations, has a common equity ratio of 40% and an S&P bond rating of BBB-, and is listed as a combination electric and gas company by *AUS Utilities Report*.

2. DCF Approach

Q. PLEASE SUMMARIZE DR. VANDER WEIDE'S DCF ESTIMATES.

A. On pages 17-32 of his testimony and in Schedules 1 and 2 of Exhibit No. __(JVW-1), Dr. Vander Weide develops an equity cost rate by applying a DCF model to his groups of water and gas companies. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. Dr. Vander Weide adjusts the spot dividend yield to reflect the quarterly payment of dividends. Dr. Vander Weide uses one measure of DCF expected growth - the projected EPS growth rate. He averages the EPS growth rate forecasts from (1) Wall Street analysts as provided by I/B/E/S and (2) *Value Line*. He also includes a flotation cost adjustment of five percent. Dr. Vander

Weide's DCF results are provided in Panel B of page 2 of Exhibit JRW-13. Based on these figures, Dr. Vander Weide claims that the DCF equity cost rate for the water and gas groups are 10.5% and 10.4%, respectively.

Q. WHAT ARE THE ERRORS IN DR. VANDER WEIDE'S DCF ANALYSES?

A. There are five errors: (1) the composition of the proxy companies, which was previously discussed; (2) the quarterly dividend yield adjustment is excessive; (3) the projected DCF growth rate is based entirely on overly optimistic and upwardly-biased EPS growth rate estimates of Wall Street analysts and *Value Line;* (4) the market-value weighting of the DCF equity cost rate results; and (5) the flotation cost adjustment is inappropriate. The proxy groups were addressed above. The other issues are discussed below.

DCF Dividend Yield Adjustment

Q. PLEASE DISCUSS THE ADJUSTMENT TO THE DIVIDEND YIELD TO REFLECT THE QUARTERLY PAYMENT OF DIVIDENDS.

A. Dr. Vander Weide uses DCF dividend yields of 3.25% for the water group and 4.8% for the gas group. In Appendix 2 of his testimony, Dr. Vander Weide discusses the adjustments he makes to his spot dividend yields to account for the quarterly payment of dividends. This includes an adjustment to reflect the time value of money. The quarterly timing adjustment is in error and results in an overstated equity cost rate. First, as discussed above, the appropriate dividend yield adjustment for growth in the DCF model is the expected dividend for the next quarter multiplied by four. The quarterly adjustment procedure is inconsistent with this approach.

Second, Dr. Vander Weide's approach presumes that investors require additional compensation during the coming year because their dividends are paid out quarterly instead of being paid all in a lump sum. Therefore, he compounds each dividend to the end of the year using the long-term growth rate as the compounding factor. The error in this logic and approach is that the investor receives the money from each quarterly dividend and has the option to reinvest it as he or she chooses. This reinvestment generates its own compounding, but it is outside of the dividend payments of the issuing company. Dr. Vander Weide's approach serves to duplicate this compounding process, thereby inflating the return to the investor. Finally, the notion that an adjustment is required to reflect the quarterly timing issue is refuted in a study by Richard Bower of Dartmouth College.

Bower acknowledges the timing issue and downward bias addressed by Dr. Vander Weide. However, he demonstrates that this does not result in a biased required rate of return. He provides the following assessment:[22]

> ... authors are correct when they say that the conventional cost of equity calculation is a downward-biased estimate of the market discount rate. They are not correct, however, in concluding that it has

[22] See Richard Bower, The N-Stage Discount Model and Required Return: A Comment," *Financial Review* (February 1992), pp 141-9.

> a bias as a measure of required return. As a measure of required return, the conventional cost of equity calculation (K*), ignoring quarterly compounding and even without adjustment for fractional periods, serves very well.

He also makes the following observation on the issue:

> Too many rate cases have come and gone, and too many utilities have survived and sustained market prices above book, to make downward bias in the conventional calculation of required return a likely reality.

DCF Growth Rate

Q. PLEASE REVIEW DR. VANDER WEIDE'S DCF GROWTH RATE.

A. Dr. Vander Weide DCF growth rate is the average of the projected EPS growth rate forecasts: (1) Wall Street analysts as compiled by I/B/E/S; and (2) *Value Line*. Dr. Vander Weide employs DCF growth rates of 7.25% for the water group and 5.6% for the gas group.

Q. PLEASE DISCUSS THE ERROR IN DR. VANDER WEIDE'S DCF GROWTH RATE.

A. First, it should be noted that the projected growth rate data for the companies in the water group is limited and so you cannot give these results much weight in estimating a DCF equity cost rate for KAWC. In addition, as discussed below, the market-value weighting of the results gives excessive weight to several observations. However, the primary problem with the DCF growth rate is that Dr. Vander Weide has relied exclusively on the EPS growth rate forecasts of Wall Street analysts and *Value Line*.

Q. WHY IS IT ERRONEOUS TO RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts and *Value Line* as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Therefore, in my opinion, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. In addition, I demonstrate that *Value Line*'s EPS growth rate forecasts are consistently too high. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate.

Q. PLEASE DISCUSS DR. VANDER WEIDE'S RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE*.

A. It seems highly unlikely that investors today would rely excessively on the EPS growth rate forecasts of Wall Street analysts and ignore other growth rate measure in arriving at expected growth. As I previously indicated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historic growth prospective dividend growth, internal growth, as well as projected earnings growth. In addition, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[23] As such, the weight give to analysts' projected EPS growth rate should be limited. And finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Hence, using these growth rates as a DCF growth rate produces an overstated equity cost rate. A recent study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[24] These issues are addressed in more detail in Appendix B.

Q. DR. VANDER WEIDE HAS DEFENDED THE USE OF ANALYSTS' EPS FORECASTS IN HIS DCF MODEL BY CITING A STUDY HE PUBLISHED WITH DR. WILLARD CARLETON. PLEASE DISCUSS DR. VANDER WEIDE'S STUDY.

[23] M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[24] Easton, P., & Sommers, G. (2007). Effect of analysts' optimism on estimates of the expected rate of return implied by earnings forecasts. *Journal of Accounting Research*, 45(5), 983–1015.

A. Dr. Vander Weide cites the study on page 23 of his testimony. In the study, Dr. Vander Weide performs a linear regression of a company's stock price to earnings ratio (P/E) on the dividend yield payout ratio (D/E), alternative measures of growth (g), and four measures of risk (beta, covariance, r-squared, and the standard deviation of analysts' growth rate projections). He performed the study for three one-year periods – 1981-1982, and 1983 – and used a sample of approximately 65 companies. His results indicated that regressions measuring growth as analysts' forecasted EPS growth were more statistically significant that those using various historic measures of growth. Consequently, he concluded that analysts' growth rates are superior measures of expected growth.

Q. PLEASE CRITIQUE DR. VANDER WEIDE'S STUDY.

A. Before highlighting the errors in the study, it is important to note that the study was published more twenty years ago, used a sample of only sixty five companies, and evaluated a three-year time period (1981-83) that was over twenty-five years ago. Since that time, many more exhaustive studies have been performed using significantly larger data bases and, from these studies, much has been learned about Wall Street analysts and their stock recommendations and earnings forecasts. Nonetheless, there are several errors that invalidate the results of the study.

Q. PLEASE DESCRIBE THE ERRORS IN DR. VANDER WEIDE'S STUDY.

A. The primary error in the study is that his regression model is misspecified. As a result, he cannot conclude whether one growth rate measure is better than the other. The misspecification results from the fact that Dr. Vander Weide did not actually employ a modified version of the DCF model. Instead, he used a "linear approximation." He used the approximation so that he did not have to measure k, investors' required return, directly, but instead he used some proxy variables for risk. The error in this approach is there can be an interaction between growth (g) and investors' required return (k) which could lead him to conclude that one growth rate measure is superior to others. Furthermore, due to this problem, analysts' EPS forecasts could be upwardly biased and still appear to provide better measures of expected growth.

There are other errors in the study as well that further invalidate the results. Dr. Vander Weide does not use both historic and analysts' projections growth rate measures in the same regression to assess if both historic and forecasts should be used together to measure expected growth. In addition, he did not perform any tests to determine if the difference between historic and projected growth measures is statistically significant. Without such tests, he cannot make any conclusions about the superiority of one measure versus the other.

<u>Market-Value Weighting of DCF Results</u>

Q. PLEASE DISCUSS DR. VANDER WEIDE'S MARKET-VALUE WEIGHTING OF HIS DCF RESULTS.

A. In Schedules1 and 2 of Exhibit No. __(JVW-1), Dr. Vander Weide weights the DCF results for each of his water and gas proxy companies by the market capitalization of the companies in computing his average DCF result for each proxy group. This approach gives more weight to the equity cost rate results for the larger companies and less weight to the cost rate results for the smaller companies.

Q. WHAT ARE THE PROBLEMS WITH THIS APPROACH?

A. There are several issues. First, this gives more weight to the DCF results for the larger companies. KAWC is a relatively small water company with 2012 operating revenues of $86.0 million. But this approach gives very little weight to the DCF results for small companies. The lack of weight given to the DCF results for smaller companies is exacerbated by the fact that he has ignored the equity cost rate results for the three smallest publicly-traded water companies by excluding them from his water proxy group. For his water group, the market-value weighting gives much more weight to the DCF results for American Water Works, a company whose earnings are still recovering from its failed ownership by RWE. For his gas group, the market-value weighting gives much more weight to the 12.4% DCF equity cost rate result for NiSource. As previously discussed, NiSource has a higher financial risk profile that the other gas companies and should be excluded from the gas proxy group.

Flotation Costs

Q. PLEASE DISCUSS DR. VANDER WEIDE'S ADJUSTMENT FOR FLOTATION COSTS.

A. Dr. Vander Weide claims that an upward adjustment to the equity cost rate is necessary for flotation costs. This adjustment factor is erroneous for several reasons. First, the Company has not identified any actual flotation costs for the Company. Therefore, the Company is requesting annual revenues in the form of a higher return on equity for flotation costs that have not been identified. Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, a flotation cost adjustment is justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for water utility companies are over 1.0X actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference

between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of water utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, water utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors

decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transactions costs, they have not accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in their DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

3. Risk Premium ("RP") Approach

Q. PLEASE REVIEW DR. VANDER WEIDE'S RP ANALYSES.

A. In Schedules 3, 4, 5. and 7 of Exhibit No. __(JVW-1), Dr. Vander Weide develops an equity cost rate using expected (ex ante) and historical RP models. Dr. Vander Weide's RP results are provided in Panels C and D of page 2 of Exhibit JRW-13. He reports RP equity cost rates of 11.40% using the expected return approach and 10.82% using the historical RP approach.

In his expected RP approach, Dr. Vander Weide computes an expected stock return by applying the DCF model to the S&P utilities and the S&P 500 and uses the EPS growth rate forecasts of Wall Street analysts as his growth rate. He then subtracts the yield on 'A' rated utility bonds. In his historic RP model, Dr. Vander Weide's computes a historical risk premium as the difference in the arithmetic mean stock and bond returns. The stock returns are computed for different time periods for several different indexes, including S&P and Moody's electric utility indexes as well as the S&P 500.

Q. WHAT ARE THE ERRORS IN DR. VANDER WEIDE'S RP ANALYSES?

A. The errors in Dr. Vander Weide's RP equity cost rate approaches include: (1) an inflated base interest rate; (2) an excessive risk premium which is based on the historical relationship between stock and bond returns; and (3) the inclusion of a flotation cost adjustment of 0.17%. The flotation cost issue has already been addressed. The other two issues are discussed below.

Q. PLEASE DISCUSS THE BASE YIELD OF DR. VANDER WEIDE'S RISK PREMIUM ANALYSIS.

A. The base yield in Dr. Vander Weide's RP analysis is the projected yield on 'A' rated utility bonds. There are two issues with his projected 6.60% 'A' rated utility bond yield. First, the yield is above current market rates. As shown on Page 1 of Exhibit JRW-3, the current yield on long-term, 'A' rated public utility bonds is about 4.0%. As such, his base interest rate is vastly overstated. Second, Vander Weide's base yield is erroneous and inflates the required return on equity in two ways. First, long-term bonds are subject to interest rate risk, a risk which does not affect common stockholders since dividend payments (unlike bond interest payments) are not fixed but tend to increase over time. Second, the base yield in Dr. Vander Weide's risk premium study is subject to credit risk since it is not default risk-free like an obligation of the U.S. Treasury. As a result, its yield-to-maturity includes a premium for default risk and therefore is above its expected return. Hence using such a bond's yield-to-maturity as a base yield results in an overstatement of investors' return expectations.

Q. DR. VANDER WEIDE EMPLOYS A DCF-BASED EX ANTE RISK PREMIUM APPROACH. PLEASE DISCUSS THE ERRORS IN THIS APPROACH.

A. Dr. Vander Weide computes a DCF-based equity risk premium. Dr. Vander Weide estimates an expected return using the DCF model and subtracts a concurrent measure of interest rates. He computes the expected return in this RP approach by applying the DCF model to a group of gas distribution companies on a monthly basis over the 1998-2012 time periods. He employs the EPS growth rate forecasts of Wall Street analysts as the DCF growth rate. To compute the RP, he then subtracts the yield on 'A' rated utility bonds.

The primary error in this approach is that he uses the EPS growth rate forecasts of Wall Street analysts as the one and only measure of growth in the DCF model. This issue was addressed above and in Appendix B. As I have discussed, analysts' EPS growth rate forecasts are highly inaccurate estimates of future earnings (a random walk model performs just as well), and are overly optimistic and upwardly-biased measures of actual future EPS growth for companies in general as well as for utilities. As a result, Dr. Vander Weide's ex-ante risk premium is overstated because his expected return measure is inflated.

Q. PLEASE REVIEW DR. VANDER WEIDE'S EX POST OR HISTORIC RP STUDY.

A. Dr. Vander Weide performs an ex-post or historical RP study that appears in Schedules 4 and 5 of Exhibit__(JVW-1). This study involves an assessment of the historical differences between S&P Public Utility Index and the S&P 500 stock returns and public utility bond returns over various time periods between the years 1937-2012. From the results of his study, he concludes that an appropriate risk premium is 3.80% using S&P public utility stock returns and 4.3% using S&P 500 stock returns.

Q. FIRST, HAS DR. VANDER WEIDE PROVIDED ANY EMPIRICAL EVIDENCE WHATSOEVER THAT THE S&P PUBLIC UTILITIES AND/OR THE S&P 500 COMPANIES ARE APPROPRIATE RISK

PROXIES FOR WATER COMPANIES?

A. No. Dr. Vander Weide has provided no such evidence, and as I have previously indicated, water utilities are among the least risky companies in the U.S. Hence, since Dr. Vander Weide has provided no such evidence that these are appropriate proxies for water companies, the results of this study should be ignored.

Q. PLEASE ADDRESS THE ISSUES INVOLVED IN USING HISTORICAL STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. As previously discussed, it is common to compute a market risk premium as the difference between historic stock and bond returns. However, this approach can produce differing results depending on several factors, including the measure of central tendency used, the time period evaluated, and the stock and bond market index employed. In addition, there are a myriad of empirical problems in the approach, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the "Peso Problem"), the company survivorship bias (only successful companies survive – poor companies do not survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). These issues are discussed in Appendix D of this testimony.

3. CAPM Approach

Q. PLEASE DISCUSS DR. VANDER WEIDE'S CAPM.

A. In Schedules 7 and 8 of Exhibit No. __(JVW-1), Dr. Vander Weide develops an equity cost rate using the CAPM. In Schedule 7 he employs a historical market risk premium and in Schedule 8 he uses an expected market risk premium. Dr. Vander Weide's CAPM results are provided in Panels E and F of page 2 of Exhibit JRW-13. He reports CAPM equity cost rates of 9.58% using the historical CAPM and 10.15% using the expected CAPM. He includes a flotation cost adjustment of 0.17% in each.

Dr. Vander Weide uses a risk-free interest rate of 5.11% in each CAPM and betas from *Value Line*. His historical CAPM uses the Ibbotson return data and the market risk premium is calculated as the difference between the arithmetic mean stock return and the bond income return over the 1926-2011 period. Dr. Vander Weide develops his expected market risk premium for his CAPM of 8.4% in Schedule 8 of Exhibit__JVW-1) by applying the DCF model to the companies in the S&P 500. Dr. Vander Weide estimates an expected market return of 12.6% using an adjusted dividend yield of 2.3% and an expected DCF growth rate of 10.3%.

Q. WHAT ARE THE ERRORS IN DR. VANDER WEIDE'S CAPM ANALYSIS?

A. First, Dr. Vander Weide has ignored the results of his CAPM analyses. In addition, there are several flaws with Dr. Vander Weide's CAPM: (1) his risk-free rate of 5.1%; (2) the historic and expected market risk premiums; and (3) the flotation cost adjustment.

Q. PLEASE DISCUSS DR. VANDER WEIDE'S RISK-FREE RATE OF INTEREST IN HIS CAPM.

A. Dr. Vander Weide uses a risk-free rate of interest of 5.1% in his CAPM. This figure represents the average projected rate on twenty-year Treasury bonds by *Value Line* and EIA. Such a forecast is excessive given current interest rates and recent statements from the Federal Reserve Board. The current rate on twenty-year Treasury bonds, as of March, 2013, is only 2.9%. In addition, as noted early in this testimony, the Federal Reserve Board has indicated that it will keep interest rates low for the foreseeable future. As such, Dr. Vander Weide's risk-free interest rate is overstated.

Q. PLEASE ADDRESS THE PROBLEMS WITH DR. VANDER WEIDE'S HISTORIC CAPM.

A. Dr. Vander Weide historical CAPM uses an equity risk premium of 6.6% which is based on the difference between the arithmetic mean stock and bond income returns over the 1926-2011 period. The errors associated with computing an expected equity risk premium using historical stock and bond returns are addressed in D of this testimony. In short, there are a myriad of empirical problems, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the 'Peso Problem'), the company survivorship bias (only successful companies survive – poor companies do not survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). In addition, in this case, Dr. Vander Weide has compounded the error by using the bond income return and not the actual bond return. By omitting the price change component of the bond return, he has magnified the historic risk premium by not matching the returns on stock with the actual returns on bonds.

Q. PLEASE REVIEW THE ERRORS IN DR. VANDER WEIDE'S MARKET RISK PREMIUM IN HIS EXPECTED CAPM APPROACH.

A. Dr. Vander Weide develops an expected market risk premium for his CAPM of 7.5% in Schedule 8 of Exhibit__JVW-1) by applying the DCF model to the S&P 500. Dr. Vander Weide estimates an expected market return of 12.6% using a dividend yield of 2.3% and an expected DCF growth rate of 10.3%. The expected DCF growth rate for the S&P 500 is the average of the expected EPS growth rates from I/B/E/S. This is the primary error in this approach. As previously discussed, the expected EPS growth rates of Wall Street analysts are overly optimistic and upwardly biased. In addition, as explained below, Dr. Vander Weide's projected EPS growth rate of 10.3% is inconsistent with economic and earnings growth in the U.S.

Q. BEYOND YOUR PREVIOUS DISCUSSION OF THE UPWARD BIAS IN WALL STREET ANALYSTS' AND *VALUE LINE*'S EPS GROWTH RATE FORECASTS, WHAT OTHER EVIDENCE CAN YOU PROVIDE THAT THE DR. VANDER WEIDE'S S&P 500 GROWTH RATE IS EXCESSIVE?

A. A long-term EPS growth rate of 10.3% is not consistent with historic as well as projected economic and earnings growth in the U.S for several reasons: (1) long-term EPS and economic growth, as measured by GDP, is about 2/3rds of Dr. Vander Weide's projected EPS growth rate of 10.3%; (2) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future; and (3) over time, EPS growth tends to lag behind GDP growth.

The long-term economic, earnings, and dividend growth rate in the U.S. has only been in the 5% to 7% range. I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-14, and a summary is given in the table below.

GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.74%**
S&P 500 Stock Price	**6.35%**
S&P 500 EPS	**6.96%**
S&P 500 DPS	**5.39%**
Average	**6.36%**

The results are presented graphically on page 2 of Exhibit JRW-14. In sum, the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 5% to 7% range. By comparison, Dr. Vander Weide's long-run growth rate projection of 10.3% is vastly overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by over 50% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-half of his projected growth rates.

Q. DO MORE RECENT DATA SUGGEST THAT THE U.S. ECONOMY GROWTH IS FASTER OR SLOWER THAN THE LONG-TERM DATA?

A. The more recent trends suggest lower future economic growth than the long-term historic GDP growth. The historic GDP growth rates for 10-, 20-, 30-, 40- and 50- years are presented in Panel A of page 3 of Exhibit JRW-14. These figures clearly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy. These figures indicate that Dr. Vander Weide long-term growth EPS growth rate of 10.3% is even more inflated.

Q. WHAT LEVEL OF GDP GROWTH IS FORECASTED BY ECONOMISTS AND VARIOUS GOVERNMENT AGENCIES?

A. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of page 3 of

Exhibit JRW-14. The mean 10-year nominal GDP growth forecast (as of February 2013) by economists in the recent *Survey of Professional Forecasters* is 4.8%. The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook*, forecasts long-term GDP growth of 4.5% for the period 2011-2040. The Congressional Budget Office, in its forecasts for the period 2013 to 2023, projects a nominal GDP growth rate of 4.6%. As such, projections of nominal GDP growth provide additional evidence that Dr. Vander Weide's long-term EPS growth rate of 10.3% is highly overstated.

Q. PLEASE HIGHLIGHT THE RECENT RESEARCH ON THE LINK BETWEEN ECONOMIC AND EARNINGS GROWTH AND EQUITY RETURNS.

A. Brad Cornell of the California Institute of Technology recently published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:[25]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth

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[25] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February, 2010), p. 63.

> in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

Given current inflation in the 2% to 3% range, the results imply nominal expected stock market returns in the 7% to 8% range. As such, Dr. Vander Weide's projected earnings growth rates and implied expected stock market returns and equity risk premiums are not indicative of the realities of the U.S. economy and stock market. As such, his expected CAPM equity cost rate is significantly overstated.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF DR. VANDER WEIDE'S MARKET RISK PREMIUMS.

A. Dr. Vander Weide's historical and expected market risk premiums are inflated due to errors and bias in his studies. Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. I have provided the results of recent surveys of CFOs, financial forecasters, analysts, and companies, and their equity risk premium estimates are in the 4% to 5% range and not in the 6% to 9% range. On this issue, the opinions of these market participants are especially relevant. They deal with capital markets on an ongoing basis since they must continually assess and evaluate capital costs for their companies. They are well aware of the historical equity risk premium results as published by

Ibbotson Associates as well as Wall Street analysts' EPS growth rate projections. Nonetheless, the CFOs in the March 2013 *CFO Magazine* – Duke University Survey of almost 350 CFOs shows an expected market risk premium of 4.50% over the next ten years. In addition, surveys conducted in 2012 by Fernandez indicates that financial analysts and companies are using equity risk premiums of 5.0% to 5.5%. As such, using these real world equity risk premiums, the appropriate equity cost rate for a public utility should be in the 8.0% to 9.0% range and not in the 10.9% range.

Q. PLEASE EVALUATE DR. VANDER WEIDE'S OBSERVATION THAT THE CAPM UNDERSTATES THE EQUITY COST RATE DUE TO A COMPANY'S SIZE.

A. Dr. Vander Weide claims that an adjustment is required for the size of a company when using the CAPM to estimate an equity cost rate. This adjustment is based on the historical stock market returns studies as performed and published by Ibbotson Associates. This argument is erroneous for several reasons.

First, as previously discussed, there are numerous errors in using historical market returns to compute risk premiums. These errors provide inflated estimates of expected risk premiums. Among the errors are the well-known survivorship bias (only successful companies survive – poor companies do not survive) and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). The net result is that

Ibbotson's size premiums are poor measures for any risk adjustment to account for the size of the Company.

Second, Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[26] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions and hence, their financial performance is monitored on an ongoing basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common financial transactions such as the sale of securities. Furthermore, unlike their industrial counterparts, accounting standards and reporting are fairly standardized for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclosure, utilities are much different than industrials, which could account for the lack of a size premium.

Q. PLEASE DISCUSS RECENT RESEARCH ON THE SIZE PREMIUM IN ESTIMATING THE EQUITY COST RATE.

[26] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of the Midwest Finance Association*, pp. 95-101, (1993).

A. As noted, there are a number of errors in using historical market returns to compute risk premiums. With respect to the small firm premium, Richard Roll (1983) found that one-half of the historic return premium for small companies disappears once biases are eliminated and historic returns are properly computed. The error arises from the assumption of monthly portfolio rebalancing and the serial correlation in historic small firm returns.[27]

In a more recent paper, Ching-Chih Lu (2009) estimated the size premium over the long-run. Lu acknowledges that many studies have demonstrated that smaller companies have historically earned higher stock market returns. However, Lu highlights that these studies rebalance the size portfolios on an annual basis. This means that at the end of each year the stocks are sorted based on size, split into deciles, and the returns are computed over the next year for each stock decile. This annual rebalancing creates the problem. Using a size premium in estimating a CAPM equity cost rate requires that a firm carry the extra size premium in its discount factor for an extended period of time, not just for one year, which is the presumption with annual rebalancing. Through an analysis of small firm stock returns for longer time periods (and without annual rebalancing), Lu finds that the size premium disappears within two years. Lu's conclusion with respect to the size premium is:[28]

[27] *See* Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983).

[28] Ching-Chih Lu, "The Size Premium in the Long Run," 2009 Working Paper, SSRN abstract no. 1368705.

However, an analysis of the evolution of the size premium will show that it is inappropriate to attach a fixed amount of premium to the cost of equity of a firm simply because of its current market capitalization. For a small stock portfolio which does not rebalance since the day it was constructed, its annual return and the size premium are all declining over years instead of staying at a relatively stable level. This confirms that a small firm should not be expected to have a higher size premium going forward sheerly because it is small now.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Educational Background, Research, and Related Business Experience

J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Barron's, Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call.*

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past twenty-five years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Massachusetts, Missouri, Nebraska, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Washington, and Washington, D.C. He has also prepared testimony which was submitted to the Federal Energy Regulatory Commission.

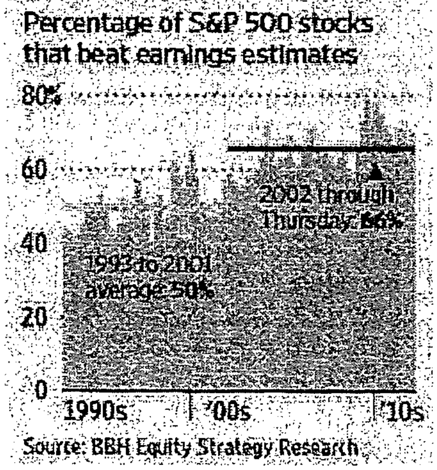
Appendix B
The Research on Analysts' Long-Term EPS Growth Rate Forecasts

Most of the attention given the accuracy of analysts' EPS forecasts comes from media coverage of company's quarterly earnings announcements. When companies' announced earnings beat Wall Street's EPS estimates ("a positive surprise"), their stock prices usually go up. When a company's EPS figure misses or is below Wall Street's forecasted EPS ("A negative surprise"), their stock price usually declines, sometimes precipitously so. Wall Street's estimate is the consensus forecast for quarterly EPS made by analysts who follow the stock as of the announcement date. And so Wall Street's estimate is the consensus EPS made in the days leading up to the EPS announcement.

In recent years, it has become more common for companies to beat Wall Street's quarterly EPS estimate. A recent *Wall Street Journal* article summarized the results for the first quarter of 2012: "While this "positive surprise ratio" of 70% is above the 20 year average of 58% and also higher than last quarter's tally, it is just middling since the current bull market began in 2009. In the past decade, the ratio only dipped below 60% during the financial crisis. Look before 2002, though, and 70% would have been literally off the chart. From 1993 through 2001, about half of companies had positive surprises.[1] Figure 1 below provides the record for companies beating Wall Street's EPS estimate on a quarterly basis over the past twenty years.

[1] Spencer Jakab, "Earnings Surprises Lose Punch," *Wall Street Journal* (May 7, 2012), p. C1.

Figure 1
Percent of Companies Beating Wall Street's Quarterly Estimates



A. RESEARCH ON THE ACCURACY OF ANALYSTS' NEAR-TERM EPS ESTIMATES

There is a long history of studies that evaluate how well analysts forecast near-term EPS estimates and long-term EPS growth rates. Most of these studies have evaluated the accuracy of earnings forecasts for the current quarter or year. Many of the early studies indicated that analysts make overly optimistic EPS earnings forecasts for quarter-to-quarter EPS (Stickel (1990); Brown (1997); Chopra (1998)).[2] More recent studies have shown that the optimistic bias tends to be larger for longer-term forecasts and smaller for forecasts made nearer to the EPS announcement date. Richardson, Teoh, and Wysocki (2004) report that the upward bias in earnings growth rates declines in the quarters leading up to the

[2] S. Stickel, "Predicting Individual Analyst Earnings Forecasts," *Journal of Accounting Research*, Vol. 28, 409-417, 1990. Brown, L.D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal*, Vol. 53, 81-88, 1997, and Chopra, V.K., "Why So Much Error in Analysts' Earnings Forecasts?" *Financial Analysts Journal*, Vol. 54, 30-37 (1998).

earnings announcement date.[3] They call this result the "walk-down to beatable analyst forecasts." They hypothesize that the walk-down might be driven by the "earning-guidance game," in which analysts give optimistic forecasts at the start of a fiscal year, then revise their estimates downwards until the firm can beat the forecasts at the earnings announcement date.

However, two regulatory developments over the past decade have potentially impacted analysts' EPS growth rate estimates. First, Regulation Fair Disclosure ("Reg FD") was introduced by the Securities and Exchange Commission ("SEC") in October of 2000. Reg FD prohibits private communication between analysts and management so as to level the information playing field in the markets. With Reg FD, analysts are less dependent on gaining access to management to obtain information and therefore, are not as likely to make optimistic forecasts to gain access to management. Second, the conflict of interest within investment firms with investment banking and analyst operations was addressed in the Global Analysts Research Settlements ("GARS"). GARS, as agreed upon on April 23, 2003, between the SEC, NASD, NYSE and ten of the largest U.S. investment firms, includes a number of regulations that were introduced to prevent investment bankers from pressuring analysts to provide favorable projections.

[3] S. Richardson, S. Teoh, and P. Wysocki, "The Walk-Down to Beatable Analyst Forecasts: The Role of Equity Issuance and Insider Trading Incentives," *Contemporary Accounting Research*, pp. 885–924, (2004).

The previously cited *Wall Street Journal* article acknowledged the impact of the new regulatory rules in explaining the recent results:[4] " What changed? One potential reason is the tightening of rules governing analyst contacts with management. Analysts now must rely on publicly available guidance or, gasp, figure things out by themselves. That puts companies, with an incentive to set the bar low so that earnings are received positively, in the driver's seat. While that makes managers look good short-term, there is no lasting benefit for buy-and-hold investors."

These comments on the impact of regulatory developments on the accuracy of short-term EPS estimates was addressed in a study by Hovakimian and Saenyasiri (2010).[5] The authors investigate analysts' forecasts of annual earnings for the following time periods: (1) the time prior to Reg FD (1984-2000); (2) the time period after Reg FD but prior to GARS (2000-2002);[6] and (3) the time period after GARS (2002-2006). For the pre-Reg FD period, Hovakimian and Saenyasiri find that analysts generally make overly optimistic forecasts of annual earnings. The forecast bias is higher for early forecasts and steadily declines in the months leading up to the earnings announcement. The results are similar for the time period after Reg FD but prior to GARS. However, the bias is lower in the later forecasts (the forecasts made just prior to the announcement).

[4] Spencer Jakab, "Earnings Surprises Lose Punch," *Wall Street Journal* (May 7, 2012), p. C1.

[5] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analysts Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts* Journal (July-August, 2010), pp. 96-107.

[6] Whereas the GARS settlement was signed in 2003, rules addressing analysts' conflict of interest by separating the research and investment banking activities of analysts went into effect with the passage of NYSE and NASD rules in July of 2002.

For the time period after GARS, the average forecasts declined significantly, but a positive bias remains. In sum, Hovakimian and Saenyasiri find that: (1) analysts make overly optimistic short-term forecasts of annual earnings; (2) Reg FD had no effect on this bias; and (3) GARS did result in a significant reduction in the bias, but analysts' short-term forecasts of annual earnings still have a small positive bias.

B. RESEARCH ON THE ACCURACY OF ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS

There have been very few studies regarding the accuracy of analysts' long-term EPS growth rate forecasts. Cragg and Malkiel (1968) studied analysts' long-term EPS growth rate forecasts made in 1962 and 1963 by five brokerage houses for 185 firms. They concluded that analysts' long-term earnings growth forecasts are on the whole no more accurate than naive forecasts based on past earnings growth. Harris (1999) evaluated the accuracy of analysts' long-term EPS forecasts over the 1982-1997 time-period using a sample of 7,002 firm-year observations.[7] He concluded the following: (1) the accuracy of analysts' long-term EPS forecasts is very low; (2) a superior long-run method to forecast long-term EPS growth is to assume that all companies will have an earnings growth rate equal to historic GDP growth; and (3) analysts' long-term EPS forecasts are significantly upwardly biased, with forecasted earnings growth exceeding actual earnings growth by seven percent per annum. Subsequent studies by DeChow, P., A. Hutton, and R. Sloan (2000), and Chan, Karceski, and Lakonishok (2003) also

[7] R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999).

conclude that analysts' long-term EPS growth rate forecasts are overly optimistic and upwardly biased.[8] The Chan, Karceski, and Lakonishok (2003) study evaluated the accuracy of analysts' long-term EPS growth rate forecasts over the 1982-98 time period. They reported a median IBES growth forecast of 14.5%, versus a median realized five-year growth rate of about 9%. They also found the IBES forecasts of EPS beyond two years are not accurate. They concluded the following: "Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic."

Lacina, Lee, and Xu (2011) evaluated the accuracy of analysts' long-term earnings growth rate forecasts over the 1983-2003 time period.[9] The study included 27,081 firm year observations, and compared the accuracy of analysts' EPS forecasts to those produced by two naïve forecasting models: (1) a random walk model ("RW") where the long-term EPS (t+5) is simply equal to last year's EPS figure (t-1); (2) a RW model with drift ("RWGDP"), where the drift or growth rate is GDP growth for period t-1. In this model, long-term EPS (t+5) is simply equal to last year's EPS figure (t-1) times (1 + GDP growth (t-1)). The authors conclude that that using the RW model to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. They find that the RWGDP model performs

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[8] P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research (2000)* and K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003).

[9] M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101

better than the pure RW model, and that both models perform as well as analysts in forecasting long-term EPS. They also discover an optimistic bias in analysts' long-term EPS forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes.

C. ISSUES REGARDING THE SUPERIORITY OF ANALYSTS' EPS FORECASTS OVER HISTORIC AND TIME-SERIES ESTIMATES OF LONG-TERM EPS GROWTH

As highlighted by the classic study by Brown and Rozeff (1976) and the other studies that followed, analysts' forecasts of quarterly earnings estimates are superior to the estimates derived from historic and time-series analyses.[10] This is often attributed to the information and timing advantage that analysts have over historic and time-series analyses. These studies relate to analysts' forecasts of quarterly and/or annual forecasts, and not to long-term EPS growth rate forecasts. The previously cited studies by Harris (1999), Chan, Karceski, and Lakonishok (2003), and Lacina, Lee, and Xu (2011) all conclude that analysts' forecasts are no better than time-series models and historic growth rates in forecasting long-term EPS. Harris (1999) and Lacina, Lee, and Xu (2011) concluded that historic GDP growth was superior to analysts' forecasts for long run earnings growth. These overall results are similar to the findings by Bradshaw, Drake, Myers, and Myers (2009) that discovered that time-series estimates of annual earnings are

[10] L. Brown and M. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings," *The Journal of Finance* 33 (1): pp. 1-16 (1976).

more accurate over longer horizons than analysts' forecasts of earnings. As the authors state, "These findings suggest an incomplete and misleading generalization about the superiority of analysts' forecasts over even simple time-series-based earnings forecasts."[11]

D. STUDY OF THE ACCURACY OF ANALYSTS' LONG-TERM EARNINGS GROWTH RATES

To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In Panel A of page 1 of Exhibit JRW-B1, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate for the past twenty years.

The following example shows how the results can be interpreted. For the 3-5 year period prior to the first quarter of 1999, analysts had projected an EPS growth rate of 15.13%, but companies only generated an average annual EPS growth rate over the 3-5 years of 9.37%. This projected EPS growth rate figure represented the average projected growth rate for over 1,510 companies, with an average of 4.88 analysts' forecasts per company. For the entire twenty-year period of the study, for each quarter there were on average 5.6 analysts' EPS projections for 1,281 companies. Overall, my findings indicate that forecast errors for long-term estimates are predominantly positive, which indicates an upward bias in growth rate estimates. The mean and median forecast errors over the

[11] M. Bradshaw, M. Drake, J. Myers, and L. Myers, "A Re-examination of Analysts' Superiority Over Time-Series Forecasts," Workings paper, (1999), http://ssrn.com/abstract=1528987.

observation period are 143.06% and 75.08%, respectively. The forecasting errors are negative for only eleven of the eighty quarterly time periods: five consecutive quarters starting at the end of 1995 and six consecutive quarters starting in 2006. As shown in Panel A of page 1 of Exhibit JRW-B1, the quarters with negative forecast errors were for the 3-5 year periods following earnings declines associated with the 1991 and 2001 economic recessions in the U.S. Thus, there is evidence of a persistent upward bias in long-term EPS growth forecasts.

The average 3-5 year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1988 to 2008 are shown in Panel B of page 1 of Exhibit JRW-B1. In this graph, no comparison to actual EPS growth rates is made, and hence, there is no follow-up period. Therefore, since companies are not lost from the sample due to a lack of follow-up EPS data, these results are for a larger sample of firms. The average projected growth rate increased to the 18.0% range in 2006, and have since decreased to about 14.0%.

The upward bias in analysts' long-term EPS growth rate forecasts appears to be known in the markets. Page 2 of Exhibit JRW-B1 provides an article published in the *Wall Street Journal*, dated March 21, 2008, that discusses the upward bias in analysts' EPS growth rate forecasts.[12] In addition, a recent *Bloomberg Businessweek* article also highlighted the upward bias in analysts' EPS forecasts, citing a study by

[12] Andrew Edwards, "Study Suggests Bias in Analysts' Rosy Forecasts," *Wall Street Journal* (March 21, 2008), p. C6.

McKinsey Associates. This article is provided on pages 3 and 4 of Exhibit JRW-B1. The article concludes with the following:[13]

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

E. REGULATORY DEVELOPMENTS AND THE ACCURACY OF ANALYSTS' LONG-TERM EARNINGS GROWTH RATES FORECASTS

Whereas Hovakimian and Saenyasiri evaluated the impact of regulations on analysts' short-term EPS estimates, there is little research on the impact of Reg FD and GARS on the long-term EPS forecasts of Wall Street analysts. My study with Patrick Cusatis did find that the long-term EPS growth rate forecasts of analysts did not decline significantly and have continued to be overly-optimistic in the post Reg FD and GARS period.[14] Analysts' long-term EPS growth rate forecasts before and after GARS are about two times the level of historic GDP growth. These observations are supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. "You would have thought that, given what happened in the last three years,

[13] Roben Farzad, 'For Analysts, Things are Always Looking Up,' *Bloomberg Businessweek* (June 14, 2010), pp. 39-40.
[14] P. Cusatis and J. R. Woolridge, "The Accuracy of Analysts' Long-Term EPS Growth Rate Forecasts," Working Paper, (July 2008).

> people would have given up the ghost. But in large measure they have not.
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed. Research remains rosy and many believe it always will.[15]

These observations are echoed in a recent McKinsey study entitled "Equity Analysts: Still too Bullish" which involved a study of the accuracy on analysts long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation (emphasis added): [16]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. <u>Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two</u>

[15] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation," *Wall Street Journal*, p. C1, (January 27, 2003).
[16] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

<u>instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.</u>

F. ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS FOR UTILITY COMPANIES

To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for utility companies, I conducted a study similar to the one described above using a group of electric utility and gas distribution companies. The results are shown on Panels A and B of page 5 of Exhibit JRW-B1. The projected EPS growth rates for electric utilities have been in the 4% to 6% range over the last twenty years, with the recent figures approximately 5%. As shown, the achieved EPS growth rates have been volatile and on average, below the projected growth rates. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 4.59% and 2.90%, respectively.

For gas distribution companies, the projected EPS growth rates have declined from about 6% in the 1990s to about 5% in the 2000s. The achieved EPS growth rates have been volatile. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 5.15% and 4.53%, respectively.

Overall, the upward bias in EPS growth rate projections for electric utility and gas distribution companies is not as pronounced as it is for all companies. Nonetheless, the results here are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for utility companies.

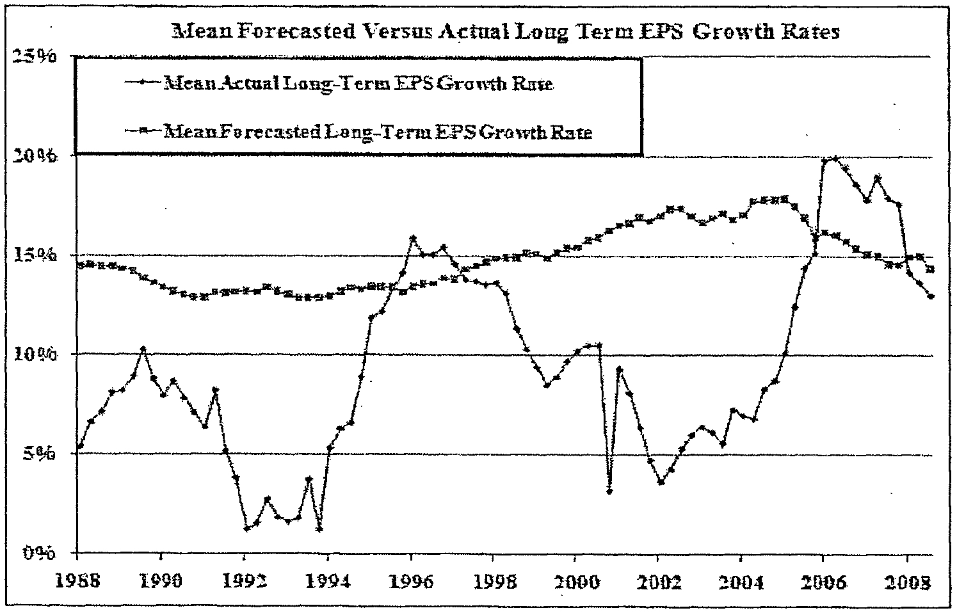
G. *VALUE LINE*'S LONG-TERM EPS GROWTH RATE FORECASTS

To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in Panel A of Page 6 of Exhibit JRW-B1. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,333 firms. The average projected EPS growth rate was 14.70%. This is high given that the average historical EPS growth rate in the U.S. is about 7%. A major factor seems to be that *Value Line* only predicts negative EPS growth for 43 companies. This is less than two percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

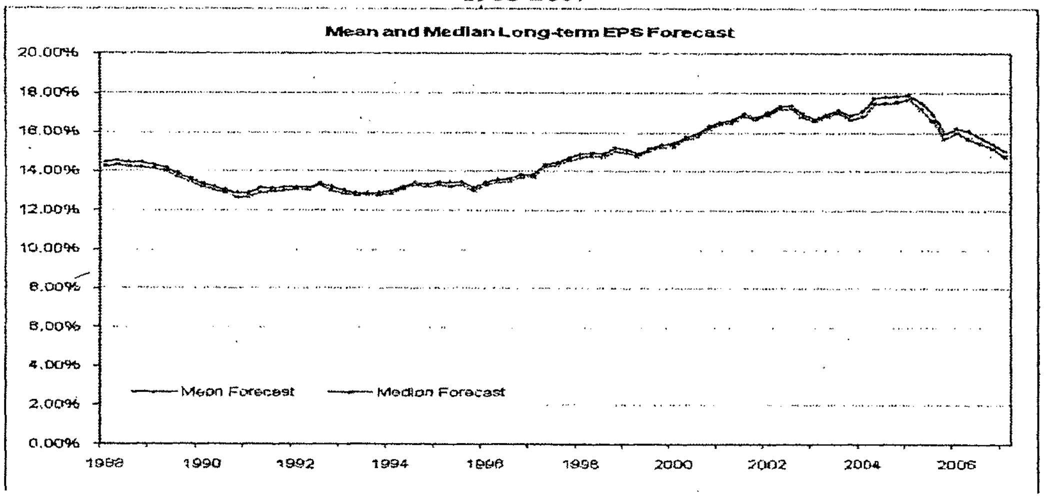
To put this figure in perspective, I screened the *Value Line* companies to see what percent of companies covered by *Value Line* had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 2,219 companies. The results are shown in Panel B of page 6 of Exhibit JRW-B1 and indicate that the average 5-year historic growth rate was 3.90%, and *Value Line* reported negative historic growth for 844 firms which represents 38.0% of these companies.

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that the analysts at *Value Line* are similar to their Wall Street brethren in that they are reluctant to forecast negative earnings growth.

Panel A
Long-Term Forecasted Versus Actual EPS Growth Rates
1988-2009



Panel B
Long-Term Forecasted EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

THE WALL STREET JOURNAL.

Study Suggests Bias in Analysts' Rosy Forecasts

By ANDREW EDWARDS
March 21, 2008; Page C6

Despite an economy teetering on the brink of a recession -- if not already in one -- analysts are still painting a rosy picture of earnings growth, according to a study done by Penn State's Smeal College of Business.

The report questions analysts' impartiality five years after then-New York Attorney General Eliot Spitzer forced analysts to pay $1.5 billion in damages after finding evidence of bias.

"Wall Street analysts basically do two things: recommend stocks to buy and forecast earnings," said J. Randall Woolridge, professor of finance. "Previous studies suggest their stock recommendations do not perform well, and now we show that their long-term earnings-per-share growth-rate forecasts are excessive and upwardly biased."

The report, which examined analysts' long-term (three to five years) and one-year per-share earnings expectations from 1984 through 2006 found that companies' long-term earnings growth surpassed analysts' expectations in only two instances, and those came right after recessions.

Over the entire time period, analysts' long-term forecast earnings-per-share growth averaged 14.7%, compared with actual growth of 9.1%. One-year per-share earnings expectations were slightly more accurate: The average forecast was for 13.8% growth and the average actual growth rate was 9.8%.

"A significant factor in the upward bias in long-term earnings-rate forecasts is the reluctance of analysts to forecast" profit declines, Mr. Woolridge said. The study found that nearly one-third of all companies experienced profit drops over successive three-to-five-year periods, but analysts projected drops less than 1% of the time.

The study's authors said, "Analysts are rewarded for biased forecasts by their employers, who want them to hype stocks so that the brokerage house can garner trading commissions and win underwriting deals."

They also concluded that analysts are under pressure to hype stocks to generate trading commissions, and they often don't follow stocks they don't like.

Write to Andrew Edwards at andrew.edwards@dowjones.com

Markets & Finance June 10, 2010, 5:00PM EST

Bloomberg Businessweek

For Analysts, Things Are Always Looking Up

They're raising earnings estimates for U.S. companies at a record pace

By Roben Farzad

For years, the rap on Wall Street securities analysts was that they were shills, reflexively producing upbeat research on companies they cover to help their employers win investment banking business. The dynamic was well understood: Let my bank take your company public, or advise it on this acquisition, and—wink, wink—I will recommend your stock through thick or thin. After the Internet bubble burst, that was supposed to change. In April 2003 the Securities & Exchange Commission reached a settlement with 10 Wall Street firms in which they agreed, among other things, to separate research from investment banking.

Seven years on, Wall Street analysts remain a decidedly optimistic lot. Some economists look at the global economy and see troubles—the European debt crisis, persistently high unemployment worldwide, and housing woes in the U.S. Stock analysts as a group seem unfazed. Projected 2010 profit growth for companies in the Standard & Poor's 500-stock index has climbed seven percentage points this quarter, to 34 percent, data compiled by Bloomberg show. According to Sanford C. Bernstein (AB), that's the fastest pace since 1980, when the Dow Jones industrial average was quoted in the hundreds and Nancy Reagan was getting ready to order new window treatments for the Oval Office.

Among the companies analysts expect to excel: Intel (INTL) is projected to post an increase in net income of 142 percent this year. Caterpillar, a multinational that gets much of its revenue abroad, is expected to boost its net income by 47 percent this year. Analysts have also hiked their S&P 500 profit estimate for 2011 to $95.53 a share, up from $92.45 at the beginning of January, according to Bloomberg data. That would be a record, surpassing the previous high reached in 2007.

With such prospects, it's not surprising that more than half of S&P 500-listed stocks boast overall buy ratings. It is telling that the proportion has essentially held constant at both the market's October 2007 high and March 2009 low, bookends of a period that saw stocks fall by more than half. If the analysts are correct, the market would appear to be attractively priced right now. Using the $95.53 per share figure, the price-to-earnings ratio of the S&P 500 is a modest 11 as of June 9. If, however, analysts end up being too high by, say, 30 percent, the P/E would jump to almost 14.

If history is any guide, chances are good that the analysts are wrong. According to a recent McKinsey report by Marc Goedhart, Rishi Raj, and Abhishek Saxena, "Analysts have been persistently over-optimistic for 25 years," a stretch that saw them peg earnings growth at 10 percent to 12 percent a year when the actual number was ultimately 6 percent. "On average," the researchers note, "analysts' forecasts have been almost 100 percent too high," even after regulations were enacted to weed out conflicts and improve the rigor of their calculations. As the chart below shows, in most years analysts have been forced to lower their estimates after it became apparent they had set them too high.

While a few analysts, like Meredith Whitney, have made their names on bearish calls, most are chronically bullish. Part of the problem is that despite all the reforms they remain too aligned with the companies they cover. "Analysts still need to get the bulk of their information from companies, which have an incentive to be over-optimistic," says Stephen Bainbridge, a professor at UCLA Law School who specializes in the securities industry. "Meanwhile, analysts don't want to threaten that ongoing access by being too negative." Bainbridge says that with the era of the overpaid, superstar analyst long over, today's job description calls for resisting the urge to be an iconoclast. "It's a matter of herd behavior," he says.

So what's a more plausible estimate of companies' earning power? Looking at factors including the strengthening dollar, which hurts exports, and higher corporate borrowing costs, David Rosenberg, chief economist at Toronto-based investment shop Gluskin Sheff + Associates, says "disappointment looms." Bernstein's Adam Parker says every 10 percent drop in the value of the euro knocks U.S. corporate earnings down by 2.5 percent to 3 percent. He sees the S&P 500 earning $86 a share next year.

As realities hit home, "It's only natural that analysts will have to revise down their views," says Todd Salamone, senior vice-president at Schaeffer's Investment Research. The market may be making its own downward adjustment, as the S&P 500 has already fallen 14 percent from its high in April. If precedent holds, analysts are bound to curb their enthusiasm belatedly, telling us next year what we really needed to know this year.

The bottom line: Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.

Bloomberg Businessweek Senior Writer Farzad covers Wall Street and international finance.

The Earnings Roller Coaster

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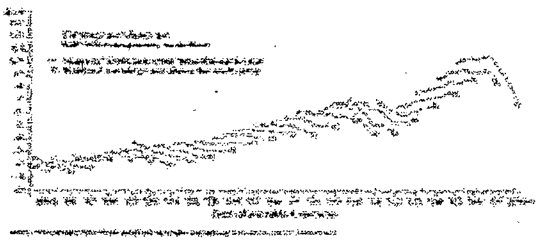
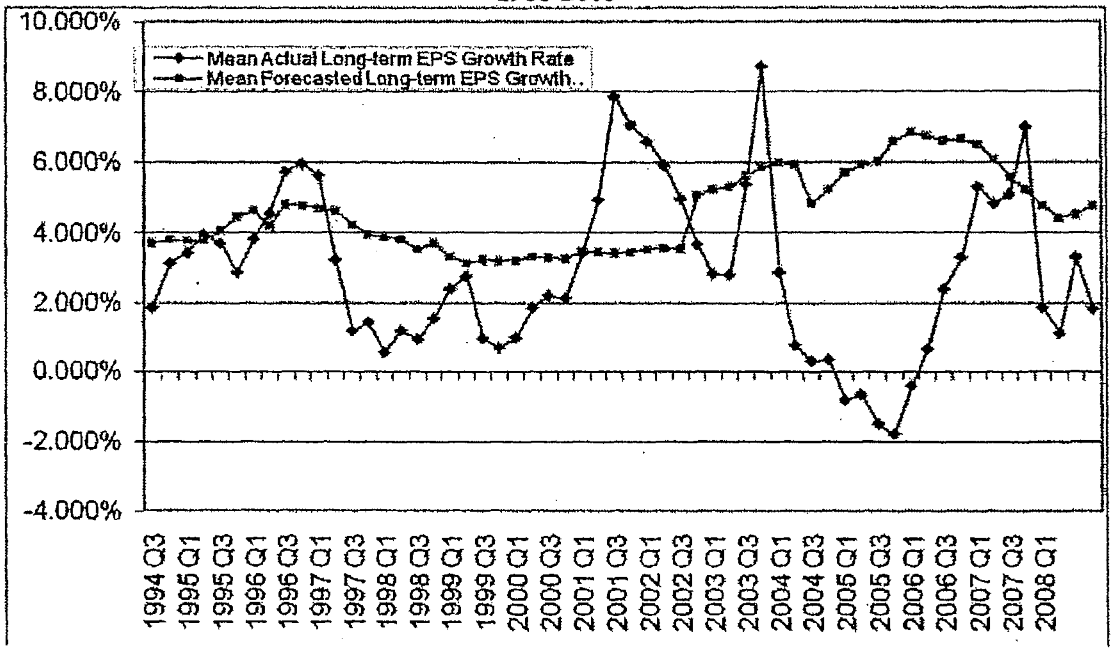
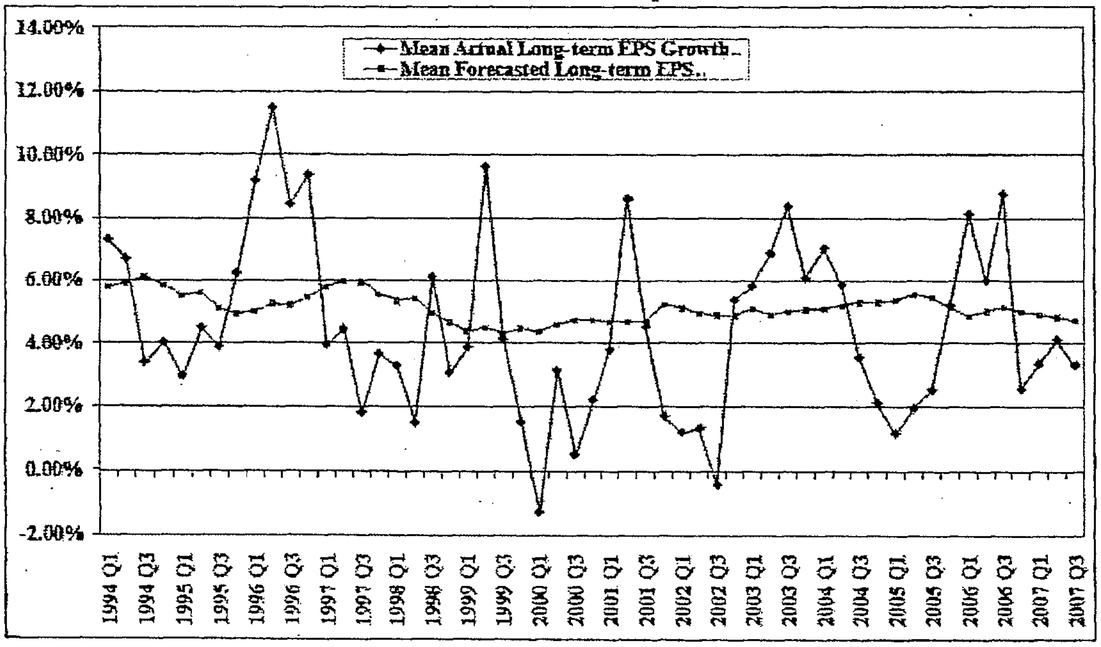


Panel A
Long-Term Forecasted Versus Actual EPS Growth Rates
Electric Utility Companies
1988-2008



Data Source: IBES

Panel B
Long-Term Forecasted Versus Actual EPS Growth Rates
Gas Distribution Companies



Panel A
Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,333 Companies	14.70%	43	1.80%

Value Line Investment Survey, June, 2012

Panel B
Historical Five-Year EPS Growth Rates for Value Line Companies

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
2,219 Companies	3.90%	844	38.00%

Value Line Investment Survey, June, 2012

Appendix C
Building Blocks Equity Risk Premium

A. THE BUILDING BLOCKS MODEL

Ibbotson and Chen (2003) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[1] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and price-earnings ("P/E") ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation ("CPI"), dividend yield ("D/P"), real earnings growth ("RG"), repricing gains ("PEGAIN") and return interaction/reinvestment ("INT").[2] This is shown on page 1 of Exhibit JRW-C1. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical U.S. Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

[1] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, (January 2003).

[2] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

The third column in the graph on page 1 of Exhibit JRW-C1 shows current inputs to estimate an ex ante expected market return. These inputs include the following:

<u>CPI</u> – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. Long term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of gross domestic product ("GDP") growth, inflation, and market returns. In the first quarter 2013 survey, published on February 15, 2013, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.30% (see Panel A of page 2 of Exhibit JRW-C1).

The University of Michigan's Survey Research Center surveys consumers on their short-term (one-year) inflation expectations on a monthly basis. As shown on page 3 of Exhibit JRW-C1, the current short-term expected inflation rate is 3.1%.

As a measure of expected inflation, I will use the average of the long-term (2.3%) and short-term (3.3%) inflation rate measures, or 2.75%.

<u>D/P</u> – As shown on page 4 of Exhibit JRW-C1, the dividend yield on the S&P 500 has fluctuated from 1.0% to almost 3.5% over the past decade. Ibbotson and Chen (2003) report that the long-term average dividend yield of the S&P 500 is 4.3%. As of March, 2013, the indicated S&P 500 dividend yield was 2.1%. I will use this figure in my ex ante risk premium analysis.

RG – To measure expected real growth in earnings, I use the historical real earnings growth rate S&P 500 and the expected real GDP growth rate. The S&P 500 was created in 1960 and includes 500 companies which come from ten different sectors of the economy. On page 5 of Exhibit JRW-C1, real EPS growth is computed using the CPI as a measure of inflation. The real growth figure over 1960-2011 period for the S&P 500 is 2.8%.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged 5.50% of U.S. GDP.[3] Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 2.5% (see Panel B of page 2 of Exhibit JRW-C1).

Given these results, I will use 2.65%, for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The P/E ratios for the S&P 500 over the past 25 years are shown on page 4 of Exhibit JRW-C1. The run-up and eventual peak in P/Es in the year 2000 is very evident in the chart. The average P/E declined until late 2006, and then increased to higher high levels, primarily due to the decline in EPS as a result of the financial crisis and the recession. As of March, 2013, the average P/E for the S&P 500 was 14X, which is in line with the historic average. Since the current figure is near the

[3]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

historic average, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return.

Expected Return form Building Blocks Approach - The current expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 1 of Exhibit JRW-C1. As shown, the expected market return of 7.50% is composed of 2.75% expected inflation, 2.10% dividend yield, and 2.65% real earnings growth rate.

This expected return of 7.50% is consistent other expected return forecasts.

1. In the first quarter 2013 *Survey of Financial Forecasters*, published on February 15, 2013 by the Federal Reserve Bank of Philadelphia, the median long-term expected return on the S&P 500 was 6.13% (see Panel D of page 2 of Exhibit JRW-C1).
2. John Graham and Campbell Harvey of Duke University conduct a quarterly survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the March 2013 survey, the mean expected return on the S&P 500 over the next ten years was 6.13%.[4]

B. THE BUILDING BLOCKS EQUITY RISK PREMIUM

[4] The survey results are available at www.cfosurvey.org.

Appendix C
Building Blocks Equity Risk Premium

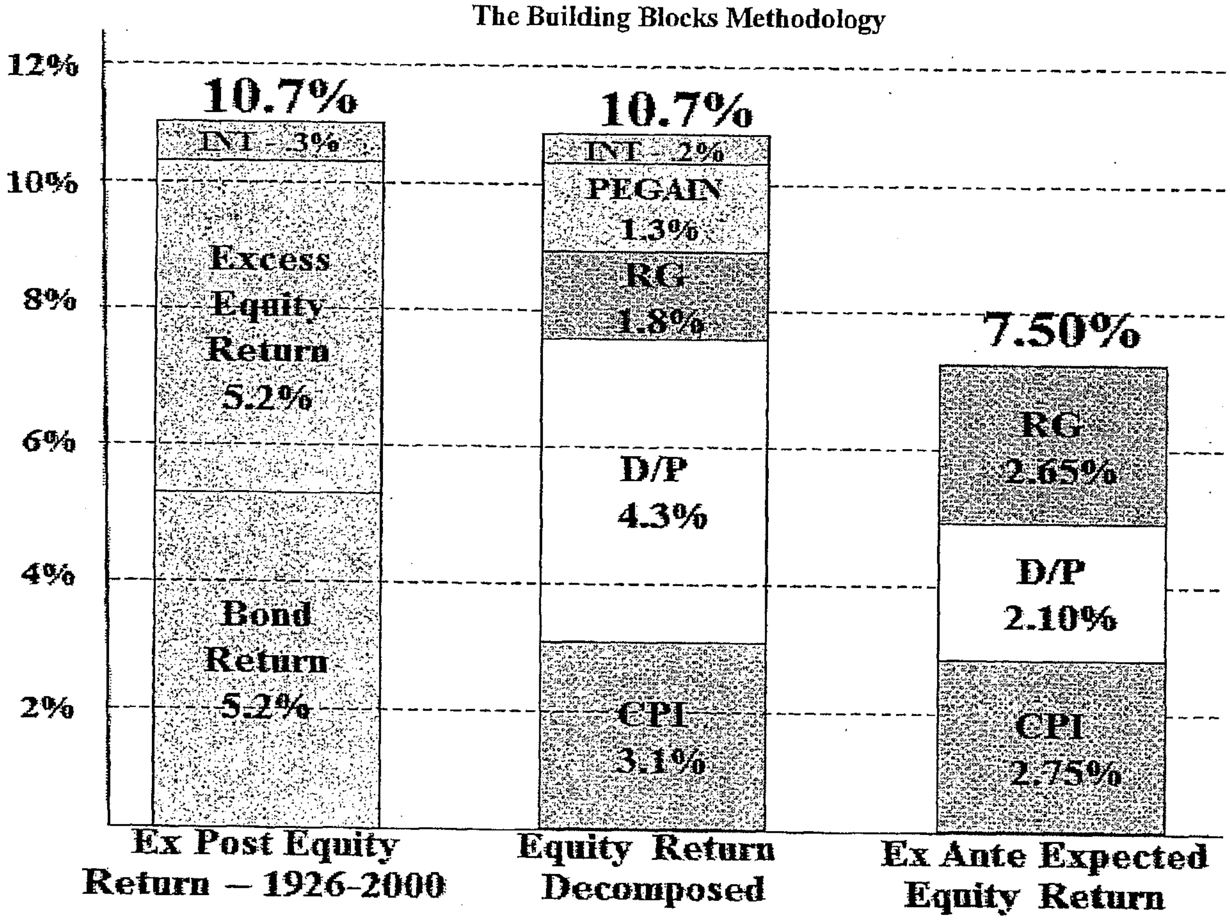
The current 30-year U.S. Treasury yield is 3.10%. This ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.5% - 3.10% = 4.40%

This is only one estimate of the equity risk premium. As shown on page 6 of Exhibit JRW-11, I am also using the results of other studies and surveys to determine an equity risk premium for my CAPM.

Exhibit JRW-C1

Decomposing Equity Market Returns
The Building Blocks Methodology



Appendix D
The Use of Historical Returns to Measure an Expected Risk Premium

It is quite common for analysts to estimate an equity or market risk premium as the difference between historical stock and bond returns. However, using the historical relationship between stock and bond returns to measure an ex ante equity risk premium can produce an inflated measure of the true market or equity risk premium. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. More significantly, there are a number of empirical issues that can result in historical returns being poor measures of the expected risk premium.

There are a number of issues in using historic returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historical bond returns

(B) Use of the arithmetic versus the geometric mean return

(C) The large error in measuring the equity risk premium using historical returns

(D) Unattainable and biased historical stock returns

(E) Company Survivorship bias

(F) The "Peso Problem" - U.S. stock market survivorship bias

These issues will be addressed in order.

A. Biased Historical Bond Returns

An essential assumption of this approach is that over long periods of time, investors' expectations are realized. However, the experienced returns of bondholders in the past invalidate this critical assumption. Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

B. The Arithmetic versus the Geometric Mean Return

The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[1] When a historic stock and bond return study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is

[1] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal*, pp. 38-47, (January-February, 1985).

selling for $100 today, increases to $200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. As further evidence of the appropriate mean return measure, the SEC requires equity mutual funds to report historic return performance using geometric mean and not arithmetic mean returns.[2] Therefore, the historic arithmetic mean return measures are biased and should be disregarded.

Nonetheless, in measuring historic returns to develop an expected equity risk premium, finance texts will often recommend the use of an arithmetic mean return as a measure of central tendency. A common justification for using the arithmetic mean return is that since annual stock returns are not serially correlated, the best measure of a return for next year is the arithmetic mean of past

2 SEC, Form N-1A.

returns. On the other hand, Damodaran suggests that such an estimate is not appropriate in estimating an equity risk premium:[3]

> "There are, however, strong arguments that can be made for the use of geometric averages. First, empirical studies seem to indicate that returns on stocks are negatively correlated over long periods of time. Consequently, the arithmetic average return is likely to overstate the premium. Second, while asset pricing models may be single period models, the use of these models to get expected returns over long periods (such as five or ten years) suggests that the estimation period may be much longer than a year. In this context, the argument for geometric average premiums becomes stronger."

C. The Error in Measuring Equity Risk Premiums with Historic Data

Measuring the equity risk premium using historical stock and bond returns is subject to a substantial forecasting error. For example, the arithmetic mean long-term equity risk premium of approximately 6.5% has a standard deviation of over 20.0%. This may be interpreted in the following way with respect to the historical distribution of the long-term equity risk premium using a standard normal distribution and a 95%, +/- 2 standard deviation confidence interval: We can say, with a 95% degree of confidence, that the true equity risk premium is between -34.7% and +47.7%. As such, the historical equity risk premium is measured with a substantial amount of error.

D. Unattainable and Biased Historic Stock Returns

Returns developed using Ibbotson's methodology are computed on stock indexes and therefore: (1) cannot be reflective of expectations because these returns

[3] Aswath. Damodaran, "A New "Risky" World Order: Unstable Risk Premiums - Implications for Practice" NYU Working Paper, 2010, p. 25.

are unattainable to investors and (2) produce biased results. This methodology assumes: (1) monthly portfolio rebalancing and (2) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption generates high transaction costs and thereby renders these returns unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[4]

Transaction costs themselves provide another bias in historic versus expected returns. In the past, the observed stock returns were not the realized returns of investors, due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades and the lack of low cost mutual funds like index funds.

E. Company Survivorship Bias

Using historic data to estimate an equity risk premium suffers from company survivorship bias. Company survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform well were dropped from these indexes is not reflected. Therefore, these stock returns are

[4] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983).

upwardly biased because they only reflect the returns from more successful companies.

F. The "Peso Problem" - U.S. Stock Market Survivorship Bias

The use of historic return data also suffers from the so-called "Peso Problem," which is also known as U.S. stock market survivorship bias. The "peso problem" issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression and other social, political, and economic events, the U.S. economy survived and did not suffer hyperinflation, invasion and/or the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the "peso problem" indicates that historic stock returns are overstated as measures of expected returns because the U.S. markets have not experienced the disruptions of other major markets around the world.

F. One of the Biggest Mistakes in Teaching Finance

Jay Ritter, a Professor of Finance at the University of Florida, identified the use of historical stock and bond return data to estimate a forward-looking equity risk premium as one of the "Biggest Mistakes" taught by the finance profession.[5] His argument is based on the theory behind the equity risk premium, the excessive results produced by historical returns, and the previously-discussed errors such as survivorship bias in historical data.

[5] Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002).

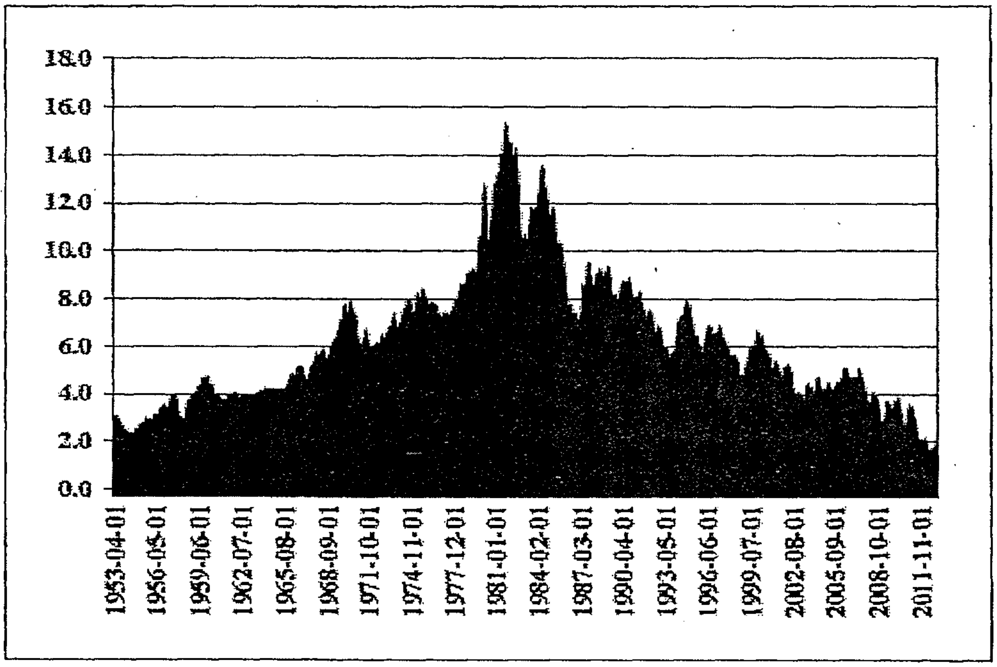
Exhibit JRW-1

Kentucky-American Water Company
Cost of Capital

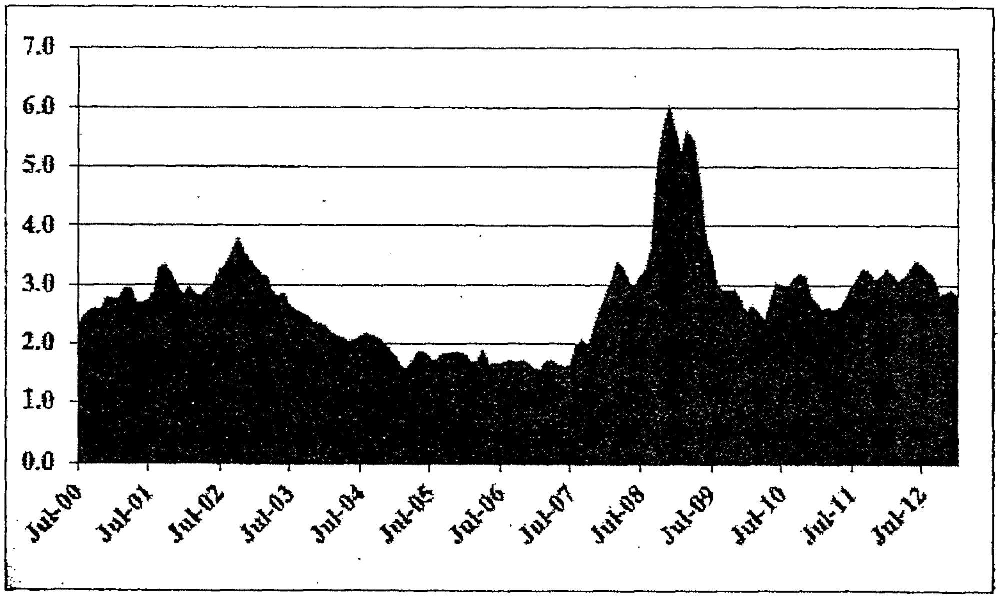
Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	2.04%	0.81%	0.02%
Long-Term Debt	52.04%	6.05%	3.15%
Preferred Stock	1.17%	8.52%	0.10%
Common Equity	44.75%	8.50%	3.80%
Total Capital	100.00%		7.07%

Exhibit JRW-2

Panel A
Ten-Year Treasury Yields
1953-Present

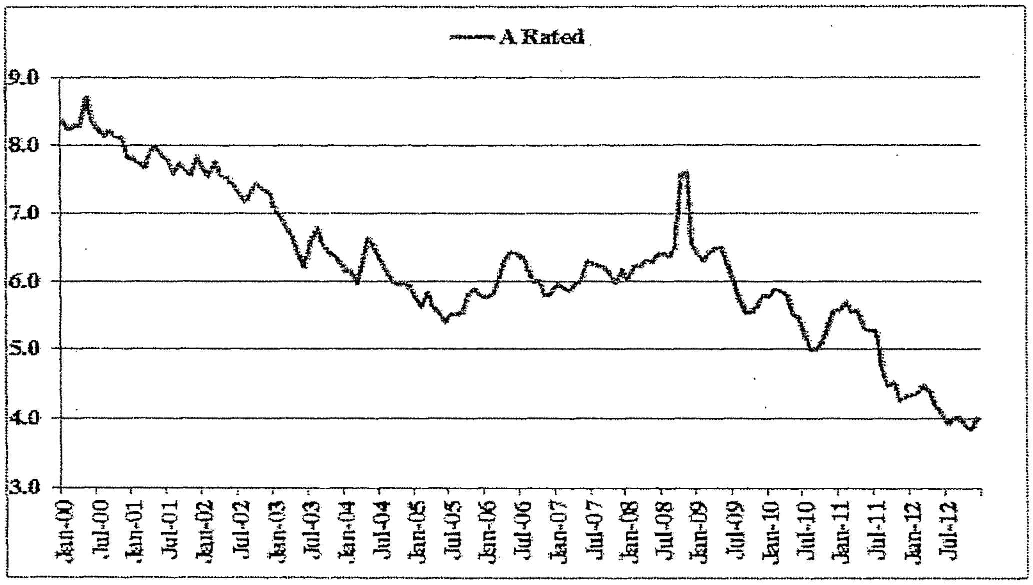


Panel B
Long-Term Moody's Baa Yields Minus Ten-Year Treasury Yields
2000-Present

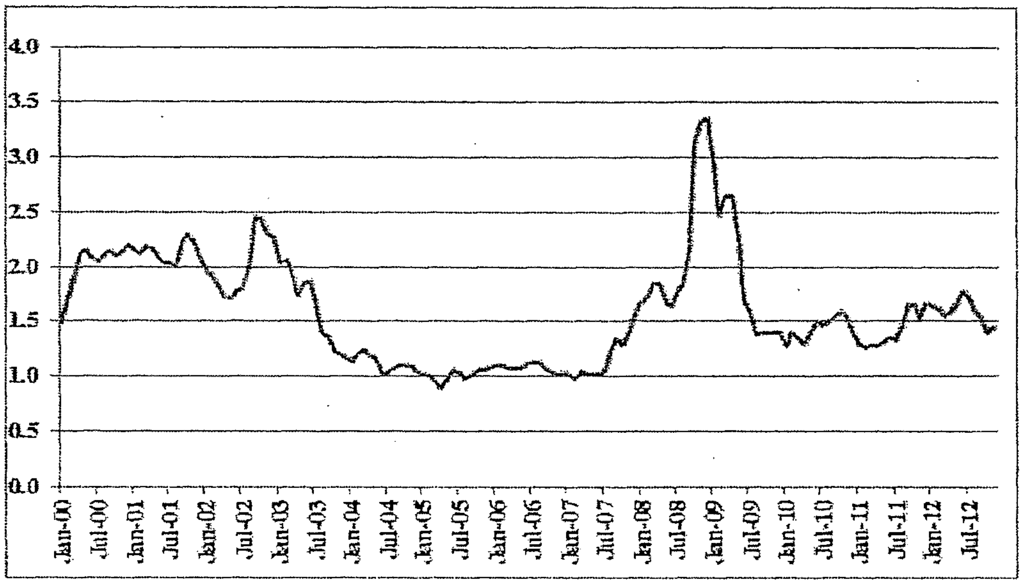


Source: Federal Reserve Bank of St. Louis, FRED Database.

Exhibit JRW-3
Panel A
Long-Term, A-Rated Public Utility Yields



Panel B
Long-Term, A-Rated Public Utility Yields minus -Twenty-Year Treasury Yields



Source: Mergent Bond Record

Panel A
Ten-Year Treasury Yields
2010 and 2012

Mar-10	3.73	Aug-12	1.68
Apr-10	3.85	Sep-12	1.72
May-10	3.42	Oct-12	1.75
Jun-10	3.20	Nov-12	1.65
Jul-10	3.01	Dec-12	1.72
Aug-10	2.70	Jan-13	1.91
Average	3.32	Average	1.74

Source: Federal Reserve Bank of St. Louis, FRED Database.

Panel B
Thirty-Year, A-Rated Public Utility Bonds
2010 and 2012

Mar-10	5.84	Aug-12	4.00
Apr-10	5.81	Sep-12	4.02
May-10	5.50	Oct-12	3.91
Jun-10	5.46	Nov-12	3.84
Jul-10	5.26	Dec-12	4.00
Aug-10	5.01	Jan-13	4.15
Average	5.48	Average	3.99

Source: Mergent Bond Record

Exhibit JRW-4
Kentucky-American Water Company
Summary Financial Statistics

Panel A
Water Proxy Group

Company	Operating Revenue ($mil)	Percent Water Revenue	Net Plant ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Market to Book Ratio
American States Water Co. (NYSE-AWR)	449.7	68	912.0	A+	A2	5.2	CA, AZ	56.6	11.8	2.17
American Water Works Co., Inc. (NYSE-AWK)	2,716.1	89	11,380.3	A	Baa1	4.3	30 States	44.5	9.9	1.50
Aqua America, Inc. (NYSE-WTR)	755.7	96	3,863.4	AA-	NR	4.4	13 States	44.2	13.0	2.83
Artesian Resources Corp. (NDQ-ARTNA)	69.7	91	362.3	NR	NR	NA	DE,MD,PA	49.5	8.7	1.53
California Water Service Group Inc. (NDQ-CWT)	541.5	100	1,443.1	AA-	NR	6.0	CA,WA,NM	46.5	9.8	1.68
Connecticut Water Service, Inc. (NDQ-CTWS)	79.8	100	422.6	A	NR	17.8	CT	37.5	11.2	2.06
Middlesex Water Company (NDQ-MSEX)	106.6	89	433.3	A	NR	5.0	NJ, DE	51.8	7.5	1.67
SJW Corporation (NYSE-SJW)	261.4	96	870.5	A	NR	4.6	CA,TX	44.3	8.6	1.80
York Water Company (NDQ-YORW)	41.1	100	238.5	A-	NR	NA	PA	53.7	9.4	2.39
Mean	558.0	92.1	2214.0	A	NR	6.8		47.6	10.0	1.96
Median	261.4	96.0	870.5	A	NR	5.0		46.5	9.8	1.80

Data Source: AUS *Utility Reports*, February 2013; Pre-Tax Interest Coverage and Primary Service Territory are from *Value Line Investment Survey*, 2013.

Panel B
Gas Proxy Group

Company	Operating Revenue ($mil)	Percent Gas Revenue	Net Plant ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
AGL Resources Inc. (NYSE-AGL)	3,494.0	71	8,212.0	A-	A1/A2	6.5	GA,TN,VA,NJ, FL,MD,IL	42.3	7.9	1.43
Atmos Energy Corporation (NYSE-ATO)	3,438.5	70	5,475.6	BBB+	Baa1	3.1	LA,KY,TX,MS, CO,KS,KY	48.3	9.3	1.39
Laclede Group, Inc. (NYSE-LG)	1,125.5	68	1,029.5	A	A2	4.6	MO	59.8	10.7	1.46
Northwest Natural Gas Co. (NYSE-NWN)	785.0	48	1,957.2	A+	A1	3.4	OR,WA	46.7	8.6	1.64
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	1,133.4	100	2,936.5	A	A3	3.4	NC,SC,TN	47.1	10.9	2.21
South Jersey Industries, Inc. (NYSE-SJI)	707.3	67	1,463.0	A	A2	6.3	NJ	43.4	16.0	2.33
Southwest Gas Corporation (NYSE-SWX)	1,956.9	70	3,299.6	BBB+	Baa1	3.8	AZ,NV,CA	50.1	10.3	1.57
WGL Holdings, Inc. (NYSE-WGL)	2,425.3	46	2,667.4	A+	A2	5.7	DC,MD,VA	59.5	11.3	1.62
Mean	1,883.2	68	3,380.1	A/A-	A2/A3	4.6		49.7	10.6	1.71
Median	1,545.2	69	2,802.0	A/A-	A2/A3	4.2		47.7	10.5	1.60

Data Source: AUS *Utility Reports*, February 2013; Pre-Tax Interest Coverage and Primary Service Territory are from *Value Line Investment Survey*, 2013.

Exhibit JRW-4
Kentucky-American Water Company
***Value Line* Risk Metrics**

Panel A
Water Proxy Group

Company	Beta	Safety Rank	Financial Strength	Earnings Predictability	Price Stability
American States Water Co. (NYSE-AWR)	0.70	2	A	90	90
American Water Works Co., Inc. (NYSE-AWK)	0.65	3	B	20	95
Aqua America, Inc. (NYSE-WTR)	0.60	2	B++	100	100
Artesian Resources Corp. (NDQ-ARTNA)	0.55	2	B++	85	100
California Water Service Group (NYSE-CWT)	0.65	3	B+	90	100
Connecticut Water Service, Inc. (NDQ-CTWS)	0.75	3	B+	85	90
Middlesex Water Company (NDQ-MSEX)	0.70	2	B+	85	95
SJW Corporation (NYSE-SJW)	0.85	3	B+	80	80
York Water Company (NDQ-YORW)	0.70	2	B++	100	95
Mean	0.68	2.4	B+	82	94

Data Source: *Value Line Investment Survey*, 2013.

Panel B
Gas Proxy Group

Company	Beta	Safety Rank	Financial Strength	Earnings Predictability	Price Stability
AGL Resources Inc. (NYSE-ATG)	0.75	1	A	75	100
Atmos Energy Corporation (NYSE-ATO)	0.70	2	B++	90	100
Laclede Group, Inc. (NYSE-LG)	0.55	2	B++	80	100
Northwest Natural Gas Co. (NYSE-NWN)	0.60	1	A	90	100
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	0.65	2	B++	100	100
South Jersey Industries, Inc. (NYSE-SJI)	0.65	2	B++	85	100
Southwest Gas Corporation (NYSE-SWX)	0.75	3	B	75	100
WGL Holdings, Inc. (NYSE-WGL)	0.65	1	A	95	100
Mean	0.66	1.8	B++	86	100

Data Source: *Value Line Investment Survey*, 2013.

Exhibit JRW-5
Kentucky-American Water Company
Capital Structure Ratios and Cost of Capital

Panel A - KAWC's Proposed Capitalization Ratios and Senior Capital Cost Rates

Capital Source	Capitalization Ratio	Cost Rates
Short-Term Debt	2.04%	0.81%
Long-Term Debt	52.04%	6.14%
Preferred Stock	1.17%	8.52%
Common Equity	44.75%	

Panel B - AG's Proposed Capitalization Ratios and Senior Capital Cost Rates

Capital Source	Capitalization Ratio	Cost Rates
Short-Term Debt	2.04%	0.50%
Long-Term Debt	52.04%	6.05%
Preferred Stock	1.17%	8.52%
Common Equity	44.75%	

Exhibit JRW-5
Kentucky-American Water Company
Capital Structure Ratios and Cost of Capital

Panel A - Short-Term Interest Rates

Federal Reserve Rates

Rate	Current	1 Year Prior	Rate	Current	1 Year Prior
Fed Funds Rate	0.17	0.13	USD LIBOR 1-Month	0.20	0.24
Fed Reserve Target	0.25	0.25	USD LIBOR 3-Month	0.28	0.47
Prime Rate	3.25	3.25			

Source: www.bloomberg.com

Panel B - Long-Term Debt Cost Rate

KENTUCKY-AMERICAN WATER COMPANY
[illegible]
[illegible]
[illegible]

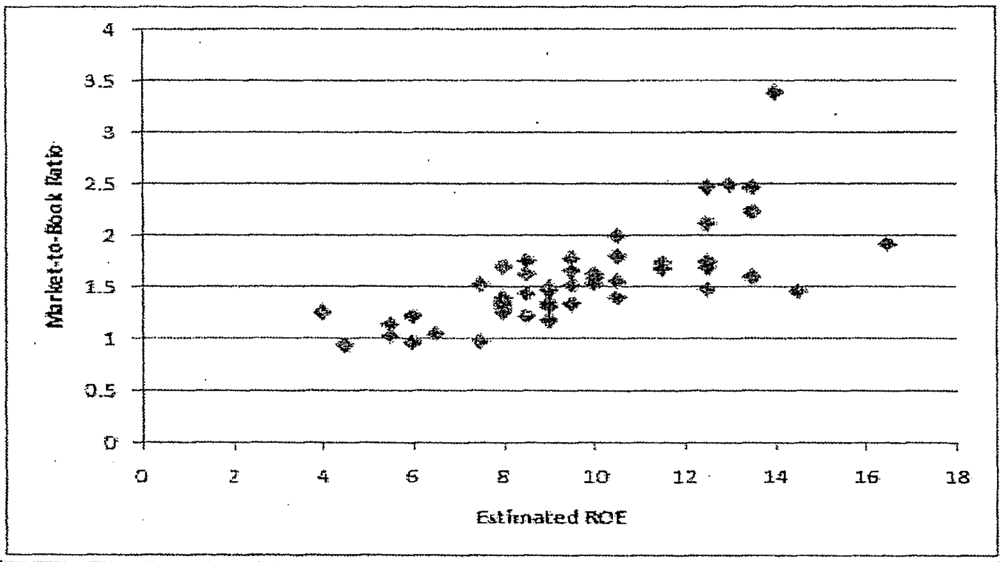
[illegible]
[illegible]
[illegible]
[illegible]

[illegible]
[illegible]
[illegible]
[illegible]

Line No.	Debt Issue Type/Rate	Issue Date	Maturity Date	Amount Outstanding	Coupon Rate	[illegible]	[illegible]	[illegible]	Principal Amount	Annual Amort. [illegible] Expense	Unamortized Discount or Premium	Unamortized Debt Expense	Unamortized Gain/Loss	Carrying Value
1														
2														
3	[illegible]													
4														
5	[illegible]	12/01/[illegible]	12/01/25	7,000,000	8.[illegible]%	7.[illegible]%	N/A	490,420	7,000,000	[illegible]	0	[illegible]	0	[illegible]
6	[illegible]	[illegible]/14/[illegible]	[illegible]/01/27	7,500,000	7.150%	7.122%	N/A	538,650	7,500,000	2,[illegible]	0	[illegible]	0	7,[illegible],019
7	[illegible]	[illegible]	[illegible]	[illegible],000,000	6.[illegible]%	7.[illegible]%	N/A	[illegible]	[illegible]	[illegible]	0	45,[illegible]	0	[illegible]
8	[illegible]	[illegible]	[illegible]	47,000,000	6.[illegible]%	[illegible]	N/A	[illegible]	47,000,000	16,[illegible]	0	[illegible]	0	[illegible]
9	[illegible]	[illegible]	[illegible]	45,[illegible],000	[illegible]	[illegible]	N/A	[illegible]	45,350,000	[illegible]	0	506,356	0	44,[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	5.[illegible]%	[illegible]	N/A	[illegible]	[illegible],000,000	[illegible]	0	[illegible]	0	[illegible]
11	[illegible]	[illegible]/01/10	[illegible]	26,000,000	[illegible]	[illegible]	N/A	[illegible]	26,000,000	[illegible]	0	[illegible]	0	25,719,[illegible]
12	[illegible]	11/01/10	11/01/[illegible]	20,000,000	[illegible]	[illegible]	N/A	[illegible]	20,000,000	0	0	0	0	20,000,000
13	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	N/A	[illegible]	[illegible]	[illegible]	0	[illegible]	0	7,[illegible]
14	[illegible]	[illegible]	[illegible]	3,000,000	[illegible]	4.[illegible]%	N/A	[illegible]	3,000,000	[illegible]	0	[illegible]	0	2,[illegible]
15	[illegible]	11/15/[illegible]	11/15/[illegible]	3,000,000	4.[illegible]%	4.[illegible]%	N/A	[illegible]	3,000,000	[illegible]	0	[illegible]	0	2,[illegible]
16	[illegible]	[illegible]/10/14	[illegible]	3,000,000	4.[illegible]%	4.[illegible]%	N/A	129,[illegible]	3,000,000	[illegible]	0	[illegible]	0	[illegible]
17														
18														
19														
20														
21														
22														
23														
24														
25	Total Long-Term Debt/Annualized Cost			[illegible]				[illegible]	[illegible]	[illegible]	$0	[illegible]	$0	[illegible]
26														
27														
28	Annualized Cost Rate			[illegible]										

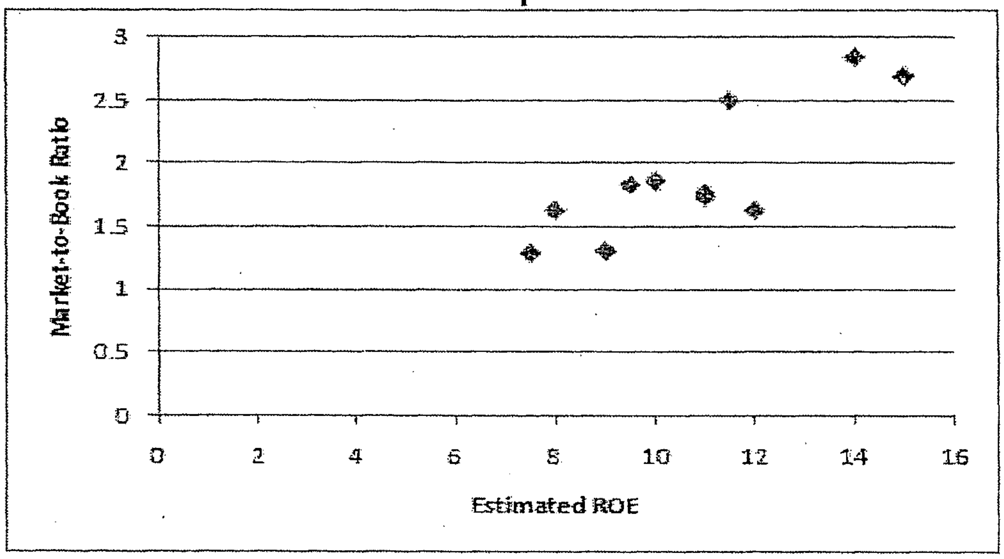
Source: www.KAWC Response to PSC 2-45, page 2.

Exhibit JRW-6
Electric Utilities
Panel A



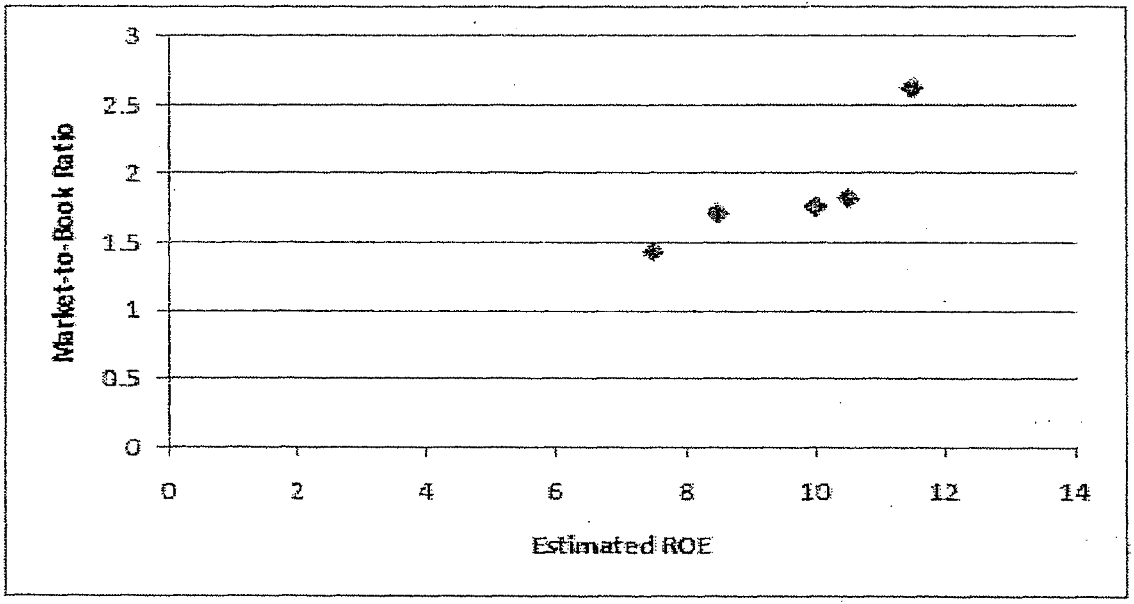
R-Square = .52, N=51.

Panel B
Gas Companies



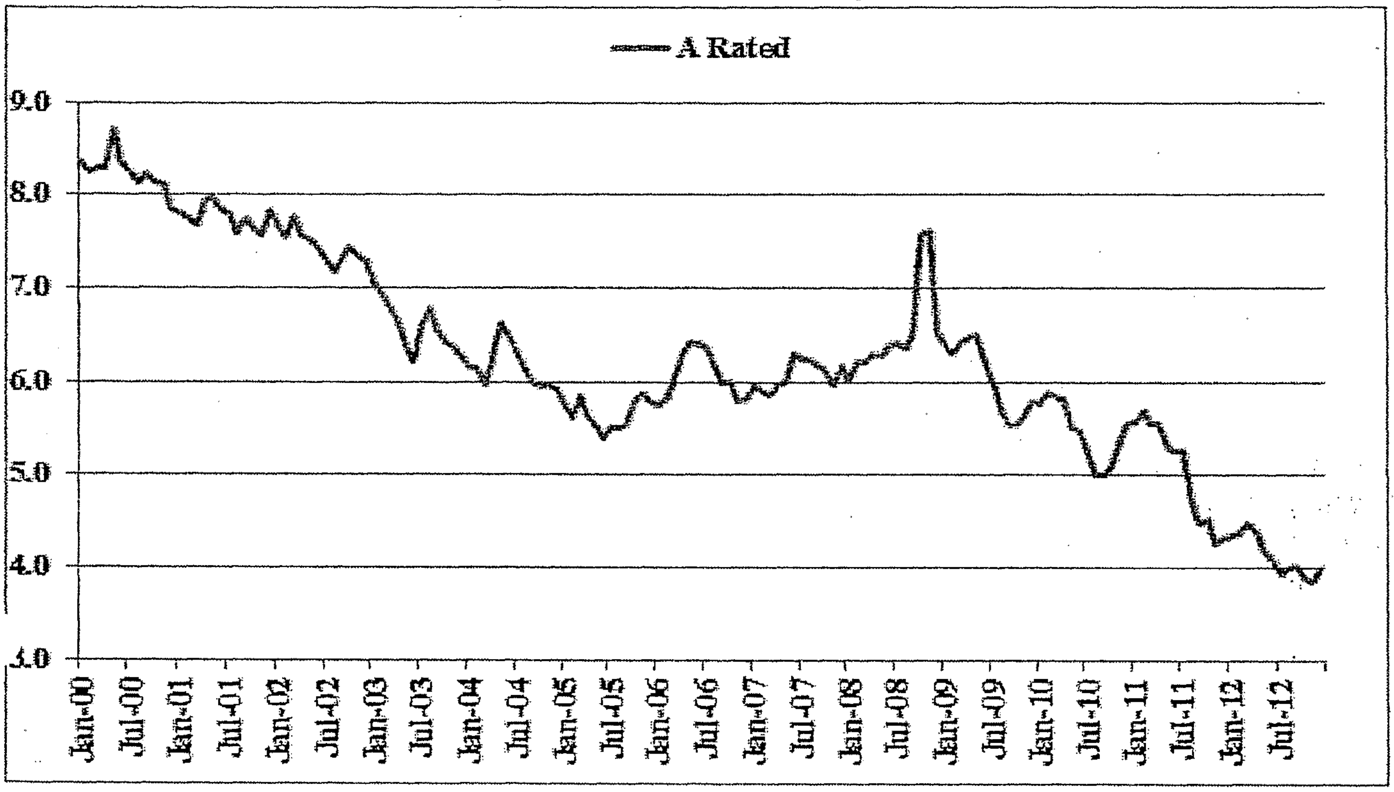
R-Square = .71, N=11.

Exhibit JRW-6
Water Companies
Panel C



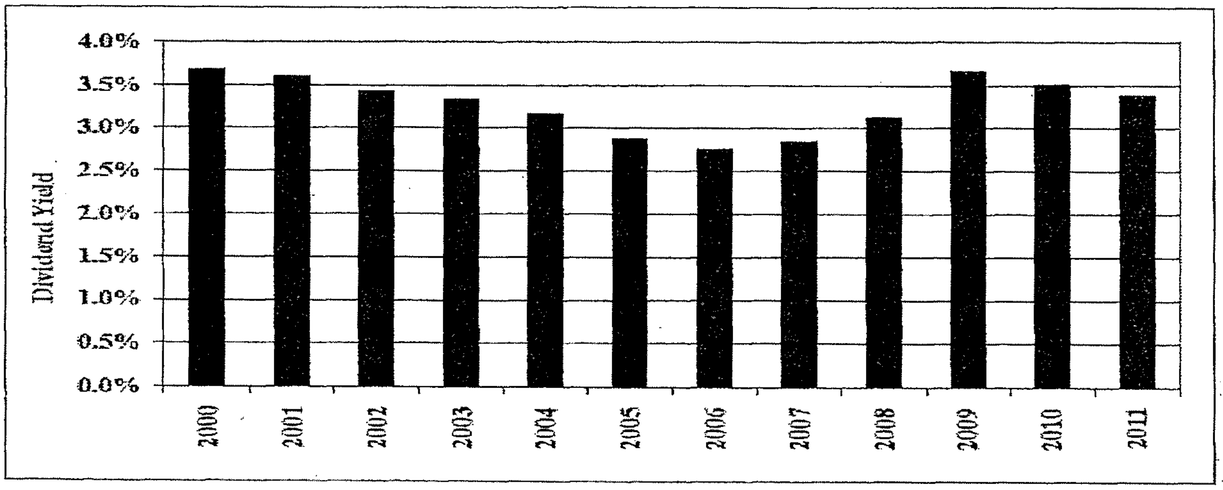
R-Square = .77, N=5.

Exhibit JRW-7
Long-Term 'A' Rated Public Utility Bonds

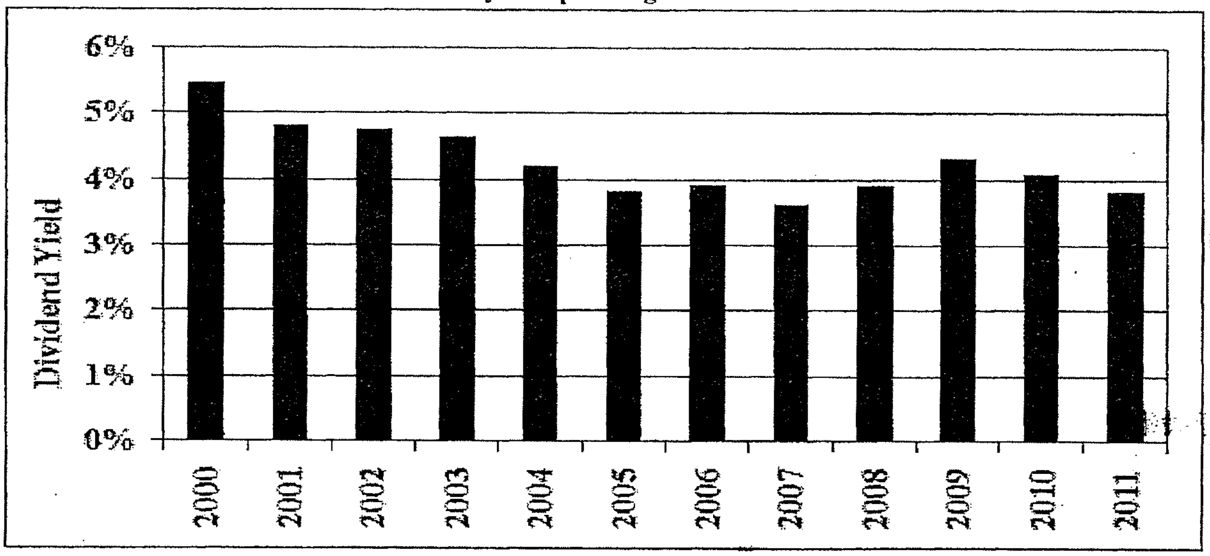


Source: Mergent Bond Record

Exhibit JRW-7
Panel A
Water Proxy Group Average Dividend Yield



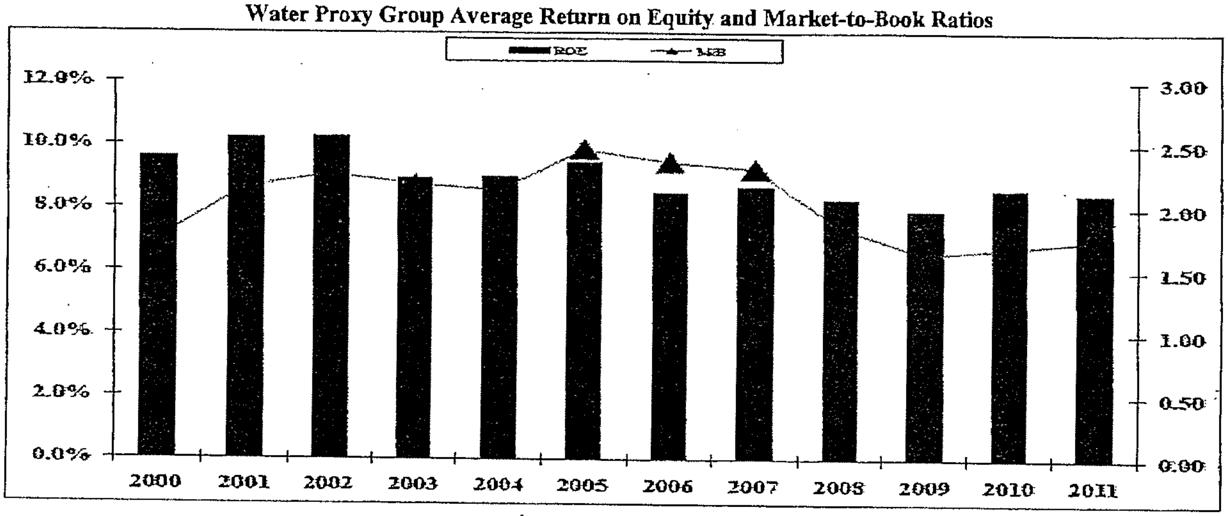
Panel B
Gas Proxy Group Average Dividend Yield



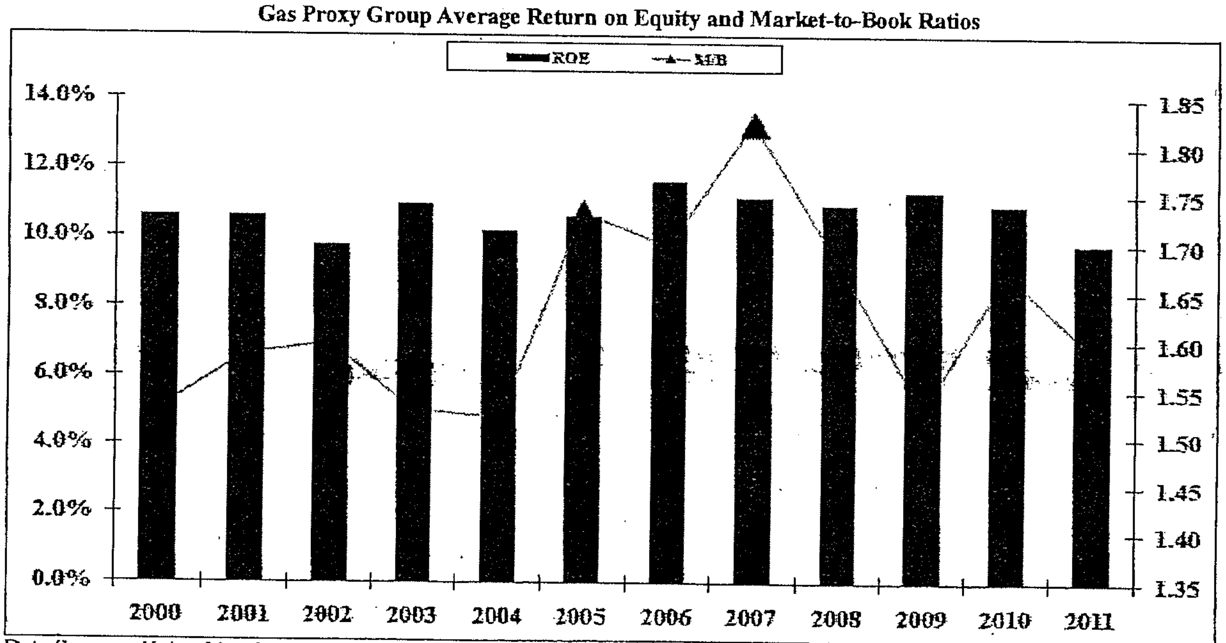
Data Source: *Value Line Investment Survey.*

Exhibit JRW-7

Panel A
Water Proxy Group Average Return on Equity and Market-to-Book Ratios



Panel B
Gas Proxy Group Average Return on Equity and Market-to-Book Ratios



Data Source: *Value Line Investment Survey.*

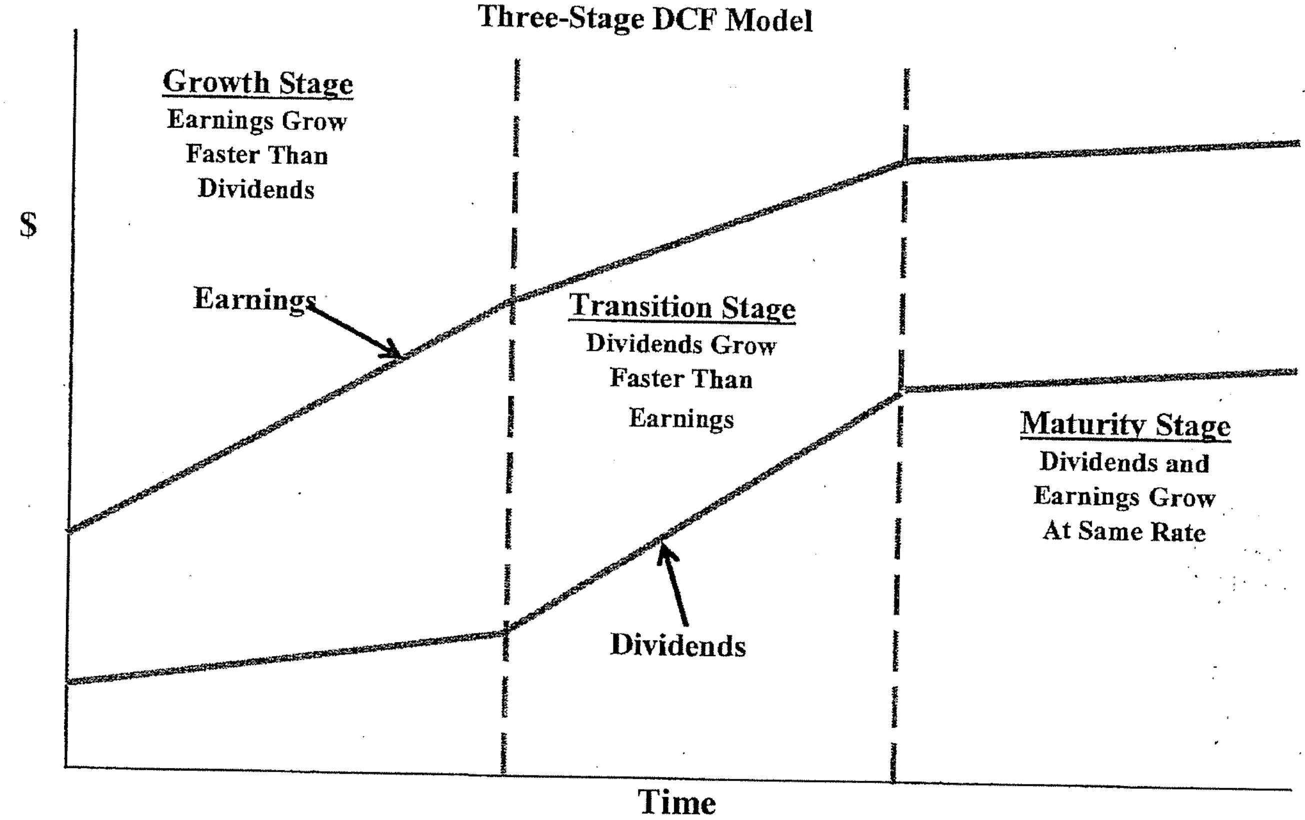
Exhibit JRW-8

Industry Average Betas

Industry Name	No.	Beta	Industry Name	No.	Beta	Industry Name	No.	Beta
Public/Private Equity	11	2.18	Natural Gas (Div.)	29	1.33	IT Services	60	1.06
Advertising	31	2.02	Financial Svcs. (Div.)	225	1.31	Retail Building Supply	8	1.04
Furn/Home Furnishings	35	1.81	Toiletries/Cosmetics	15	1.30	Computer Software	184	1.04
Heavy Truck & Equip	21	1.80	Apparel	57	1.30	Med Supp Non-Invasiv	146	1.03
Semiconductor Equip	12	1.79	Computers/Peripherals	87	1.30	Biotechnology	158	1.03
Retail (Hardlines)	75	1.77	Retail Store	37	1.29	E-Commerce	57	1.03
Newspaper	13	1.76	Chemical (Specialty)	70	1.28	Telecom. Equipment	99	1.02
Hotel/Gaming	51	1.74	Precision Instrument	77	1.28	Pipeline MLPs	27	0.98
Auto Parts	51	1.70	Wireless Networking	57	1.27	Telecom. Services	74	0.98
Steel	32	1.68	Restaurant	63	1.27	Oil/Gas Distribution	13	0.96
Entertainment	77	1.63	Shoe	19	1.25	Utility (Foreign)	4	0.96
Metal Fabricating	24	1.59	Publishing	24	1.25	Industrial Services	137	0.93
Automotive	12	1.59	Trucking	36	1.24	Bank (Midwest)	45	0.93
Insurance (Life)	30	1.58	Human Resources	23	1.24	Reinsurance	13	0.93
Oilfield Svcs/Equip.	93	1.55	Entertainment Tech	40	1.23	Food Processing	112	0.91
Coal	20	1.53	Engineering & Const	25	1.22	Medical Services	122	0.91
Chemical (Diversified)	31	1.51	Air Transport	36	1.21	Insurance (Prop/Cas.)	49	0.91
Building Materials	45	1.50	Machinery	100	1.20	Beverage	34	0.88
Semiconductor	141	1.50	Securities Brokerage	28	1.20	Telecom. Utility	25	0.88
R.E.I.T.	5	1.47	Petroleum (Integrated)	20	1.18	Tobacco	11	0.85
Homebuilding	23	1.45	Healthcare Information	25	1.17	Med Supp Invasive	83	0.85
Recreation	56	1.45	Packaging & Container	26	1.16	Educational Services	34	0.83
Railroad	12	1.44	Precious Metals	84	1.15	Environmental	82	0.81
Retail (Softlines)	47	1.44	Diversified Co.	107	1.14	Bank	426	0.77
Maritime	52	1.40	Funeral Services	6	1.14	Electric Util. (Central)	21	0.75
Office Equip/Supplies	24	1.38	Property Management	31	1.13	Electric Utility (West)	14	0.75
Cable TV	21	1.37	Pharmacy Services	19	1.12	Retail/Wholesale Food	30	0.75
Retail Automotive	20	1.37	Drug	279	1.12	Thrift	148	0.71
Chemical (Basic)	16	1.36	Aerospace/Defense	64	1.10	Electric Utility (East)	21	0.70
Paper/Forest Products	32	1.36	Foreign Electronics	9	1.09	Natural Gas Utility	22	0.66
Power	93	1.35	Internet	186	1.09	Water Utility	11	0.66
Petroleum (Producing)	176	1.34	Information Services	27	1.07	Total Market	5891	1.15
Electrical Equipment	68	1.33	Household Products	26	1.07			
Metals & Mining (Div.)	73	1.33	Electronics	139	1.07			

Source: Damodaran Online 2012 - http://pages.stern.nyu.edu/~adamodar/

Exhibit JRW-9
Three-Stage DCF Model



Source: William F. Sharpe, Gordon J. Alexander, and Jeffrey V. Bailey, Investments (Prentice-Hall, 1995), pp. 590-91.

Exhibit JRW-10

Kentucky-American Water Company
Discounted Cash Flow Analysis

Panel A
Water Proxy Group

Dividend Yield*	3.00%
Adjustment Factor (1 + 1/2g)	1.0275
Adjusted Dividend Yield	3.08%
Growth Rate**	5.50%
Equity Cost Rate	8.6%

* Page 2 of Exhibit JRW-10 and testimony at page 30.
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-10

Panel B
Gas Proxy Group

Dividend Yield*	3.90%
Adjustment Factor (1 + 1/2g)	1.0225
Adjusted Dividend Yield	3.99%
Growth Rate**	4.50%
Equity Cost Rate	8.5%

* Page 2 of Exhibit JRW-10 and testimony at page 30.
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-10

Exhibit JRW-10

Kentucky-American Water Company
Monthly Dividend Yields

Panel A
Water Proxy Group

Company	Oct	Nov	Dec	Jan	Feb	Mar	Mean
American States Water Co. (NYSE-AWR)	3.3%	3.2%	3.3%	3.0%	2.8%	2.7%	3.1%
American Water Works Co., Inc. (NYSE-AWK)	2.7%	2.7%	2.7%	2.6%	2.6%	2.5%	2.6%
Aqua America, Inc. (NYSE-WTR)	2.7%	2.6%	2.8%	2.8%	2.6%	2.4%	2.7%
Artesian Resources Corp. (NDQ-ARTNA)	3.5%	3.3%	3.8%	3.8%	3.6%	3.6%	3.6%
California Water Service Group (NYSE-CWT)	3.4%	3.3%	3.6%	3.5%	3.3%	3.3%	3.4%
Connecticut Water Service, Inc. (NDQ-CTWS)	3.1%	3.1%	3.2%	3.3%	3.3%	3.2%	3.2%
Middlesex Water Company (NDQ-MSEX)	3.9%	3.9%	4.1%	4.0%	3.9%	3.9%	4.0%
SJW Corporation (NYSE-SJW)	2.8%	2.8%	3.0%	2.8%	2.7%	2.6%	2.8%
York Water Company (NDQ-YORW)	2.9%	3.0%	3.1%	3.1%	3.0%	2.9%	3.0%
Mean	3.1%	3.1%	3.3%	3.2%	3.1%	3.0%	3.1%
Median	3.1%	3.1%	3.2%	3.1%	3.0%	2.9%	3.1%

Data Source: AUS *Utility Reports*, monthly issues.

Panel B
Gas Proxy Group

Company	Oct	Nov	Dec	Jan	Feb	Mar	Mean
AGL Resources Inc. (NYSE-ATG)	4.5%	4.5%	4.8%	4.6%	4.5%	4.7%	4.6%
Atmos Energy Corporation (NYSE-ATO)	3.9%	3.7%	4.0%	3.9%	3.8%	3.7%	3.8%
Laclede Group, Inc. (NYSE-LG)	4.0%	3.8%	4.2%	4.3%	4.4%	4.2%	4.2%
Northwest Natural Gas Co. (NYSE-NWN)	3.6%	3.6%	4.2%	4.1%	4.2%	4.0%	4.0%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	3.7%	3.7%	4.0%	3.7%	3.7%	3.7%	3.8%
South Jersey Industries, Inc. (NYSE-SJI)	3.1%	3.1%	3.3%	3.5%	3.4%	3.2%	3.3%
Southwest Gas Corporation (NYSE-SWX)	2.7%	2.6%	2.9%	2.8%	2.7%	2.6%	2.7%
WGL Holdings, Inc. (NYSE-WGL)	4.0%	4.0%	4.3%	4.0%	4.0%	3.8%	4.0%
Mean	3.7%	3.6%	4.0%	3.9%	3.8%	3.7%	3.8%
Median	3.8%	3.7%	4.1%	4.0%	3.9%	3.8%	3.9%

Data Source: AUS *Utility Reports*, monthly issues.

Exhibit JRW-10

Kentucky-American Water Company
DCF Equity Cost Growth Rate Measures
Value Line Historic Growth Rates

Panel A
Water Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
American States Water Co. (NYSE-AWR)	4.5%	2.0%	5.0%	11.5%	2.5%	5.0%
American Water Works Co., Inc. (NYSE-AWK)						
Aqua America, Inc. (NYSE-WTR)	6.5%	7.5%	9.0%	4.5%	8.0%	7.0%
Artesian Resources Corp. (NDQ-ARTNA)				2.5%	5.0%	5.5%
California Water Service Group (NYSE-CWT)	4.0%	1.0%	5.0%	5.0%	1.0%	5.0%
Connecticut Water Service, Inc. (NDQ-CTWS)	0.5%	1.5%	4.0%	4.0%	1.5%	3.0%
Middlesex Water Company (NDQ-MSEX)	2.5%	2.0%	4.5%	4.5%	1.5%	5.5%
SJW Corporation (NYSE-SJW)	2.0%	5.0%	5.5%	-3.0%	5.0%	4.5%
York Water Company (NDQ-YORW)				5.0%	4.0%	7.0%
Mean	3.3%	3.2%	5.5%	4.3%	3.6%	5.3%
Median	3.3%	2.0%	5.0%	4.5%	3.3%	5.3%
Data Source: *Value Line Investment Survey, 2013.*	Average of Median Figures =			3.9%		

Panel B
Gas Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
AGL Resources Inc. (NYSE-ATG)	8.0%	5.0%	8.0%	1.5%	6.5%	5.0%
Atmos Energy Corporation (NYSE-ATO)	5.0%	1.5%	6.5%	3.0%	1.5%	4.0%
Laclede Group, Inc. (NYSE-LG)	7.0%	2.0%	5.5%	4.0%	3.0%	6.5%
Northwest Natural Gas Co. (NYSE-NWN)	4.0%	3.0%	4.0%	4.5%	4.5%	4.0%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	5.0%	5.0%	5.0%	3.5%	5.5%	3.0%
South Jersey Industries, Inc. (NYSE-SJI)	9.5%	6.5%	10.5%	7.0%	9.5%	7.0%
Southwest Gas Corporation (NYSE-SWX)	6.0%	2.0%	4.5%	6.5%	4.0%	5.0%
WGL Holdings, Inc. (NYSE-WGL)	4.0%	2.0%	4.0%	3.0%	3.0%	4.5%
Mean	6.1%	3.4%	6.0%	4.1%	4.7%	4.9%
Median	5.5%	2.5%	5.3%	3.8%	4.3%	4.8%
Data Source: *Value Line Investment Survey, 2013.*	Average of Median Figures =			4.3%		

Exhibit JRW-10

Kentucky-American Water Company
DCF Equity Cost Growth Rate Measures
Value Line Projected Growth Rates

Panel A
Water Proxy Group

Company	*Value Line* Projected Growth Est'd. '09-'11 to '15-'17			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Sustainable Growth
American States Water Co. (NYSE-AWR)	5.5%	7.5%	2.5%	12.0%	43.0%	5.2%
American Water Works Co., Inc. (NYSE-AWK)	9.0%	6.5%	2.5%	9.0%	49.0%	4.4%
Aqua America, Inc. (NYSE-WTR)	7.0%	5.0%	4.0%	12.5%	41.0%	5.1%
Artesian Resources Corp. (NDQ-ARTNA)						
California Water Service Group (NYSE-CWT)	6.0%	3.0%	3.5%	10.5%	45.0%	4.7%
Connecticut Water Service, Inc. (NDQ-CTWS)	7.5%	3.0%	5.0%	10.5%	37.0%	3.9%
Middlesex Water Company (NDQ-MSEX)	7.0%	1.5%	3.5%	9.0%	36.0%	3.2%
SJW Corporation (NYSE-SJW)	8.0%	3.0%	4.5%	7.0%	43.0%	3.0%
York Water Company (NDQ-YORW)						
Mean	7.1%	4.2%	3.6%	10.1%	42.0%	4.2%
Median	7.0%	3.0%	3.5%	10.5%	43.0%	4.4%
Average of Median Figures =		4.5%			Median =	4.4%

Data Source: *Value Line Investment Survey, 2013.*

Panel B
Gas Proxy Group

Company	*Value Line* Projected Growth Est'd. '09-'11 to '15-'17			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
AGL Resources Inc. (NYSE-ATG)	9.0%	2.0%	5.0%	6.0%	50.0%	3.0%
Atmos Energy Corporation (NYSE-ATO)	5.5%	1.5%	5.5%	8.5%	50.0%	4.3%
Laclede Group, Inc. (NYSE-LG)	5.5%	2.0%	5.5%	10.5%	50.0%	5.3%
Northwest Natural Gas Co. (NYSE-NWN)	3.0%	2.5%	1.0%	11.5%	39.0%	4.5%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	3.0%	3.0%	4.0%	11.0%	26.0%	2.9%
South Jersey Industries, Inc. (NYSE-SJI)	9.0%	9.0%	7.0%	15.5%	48.0%	7.4%
Southwest Gas Corporation (NYSE-SWX)	8.0%	7.0%	5.0%	10.5%	58.0%	6.1%
WGL Holdings, Inc. (NYSE-WGL)	2.0%	3.0%	3.5%	9.5%	32.0%	3.0%
Mean	5.6%	3.8%	4.6%	10.4%	44.1%	4.6%
Median	5.5%	2.8%	5.0%	10.5%	49.0%	4.4%
Average of Median Figures =		4.4%			Median =	4.4%

Data Source: *Value Line Investment Survey, 2013.*

Exhibit JRW-10

Kentucky-American Water Company
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Panel A
Water Proxy Group

Company	Yahoo	Zack's	Reuters	Average
American States Water Co. (NYSE-AWR)	6.0%	6.0%	6.0%	6.0%
American Water Works Co., Inc. (NYSE-AWK)	8.5%	8.0%	9.6%	8.7%
Aqua America, Inc. (NYSE-WTR)	4.9%	6.9%	6.3%	6.0%
Artesian Resources Corp. (NDQ-ARTNA)	4.0%	n/a	n/a	4.0%
California Water Service Group (NYSE-CWT)	6.0%	5.0%	6.0%	5.7%
Connecticut Water Service, Inc. (NDQ-CTWS)	6.1%	n/a	n/a	6.1%
Middlesex Water Company (NDQ-MSEX)	2.7%	n/a	n/a	2.7%
SJW Corporation (NYSE-SJW)	14.0%	n/a	n/a	14.0%
York Water Company (NDQ-YORW)	4.9%	n/a	n/a	4.9%
Mean	6.3%	6.5%	7.0%	6.5%
Median	6.0%	6.5%	6.1%	6.0%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, March 8, 2013

Panel B
Gas Proxy Group

Company	Yahoo	Zack's	Reuters	Average
AGL Resources Inc. (NYSE-GAS)	-5.7%	3.5%	3.8%	0.5%
Atmos Energy Corporation (NYSE-ATO)	5.9%	6.0%	5.9%	6.0%
Laclede Group, Inc. (NYSE-LG)	5.3%	3.0%	n/a	4.2%
Northwest Natural Gas Co. (NYSE-NWN)	4.5%	3.8%	4.5%	4.3%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	5.6%	3.7%	5.6%	4.9%
South Jersey Industries, Inc. (NYSE-SJI)	6.0%	6.0%	n/a	6.0%
Southwest Gas Corporation (NYSE-SWX)	4.1%	4.9%	4.1%	4.3%
WGL Holdings, Inc. (NYSE-WGL)	5.3%	5.3%	5.3%	5.3%
Mean	3.9%	4.5%	4.9%	4.4%
Median	5.3%	4.4%	4.9%	4.6%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, March 8, 2013

Exhibit JRW-10

Kentucky-American Water Company
DCF Growth Rate Indicators

DCF Growth Rate Indicators

Summary Growth Rates

Growth Rate Indicator	Water Proxy Group	Gas Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	3.9%	4.3%
Projected *Value Line* Growth in EPS, DPS, and BVPS	4.5%	4.4%
Sustainable Growth ROE * Retention Rate	4.4%	4.4%
Projected EPS Growth from Yahoo, Zacks, and Reuters	6.0%	4.6%
Average of Historic and Projected Growth Rates	4.7%	4.4%
Average of Sustainable and Projected Growth Rates	5.0%	4.5%

Exhibit JRW-11

Kentucky-American Water Company
Capital Asset Pricing Model

Panel A
Water Proxy Group

Risk-Free Interest Rate	4.00%
Beta*	0.70
Ex Ante Equity Risk Premium**	5.00%
CAPM Cost of Equity	7.5%

* See page 3 of Exhibit JRW-11 and testimony at page 49.
** See pages 5 and 6 of Exhibit JRW-11

Panel B
Gas Proxy Group

Risk-Free Interest Rate	4.00%
Beta*	0.65
Ex Ante Equity Risk Premium**	5.00%
CAPM Cost of Equity	7.3%

* See page 3 of Exhibit JRW-11 and testimony at page 49.
** See pages 5 and 6 of Exhibit JRW-11

Exhibit JRW-11

Ten-Year U.S. Treasury Yields
January 2000-Present

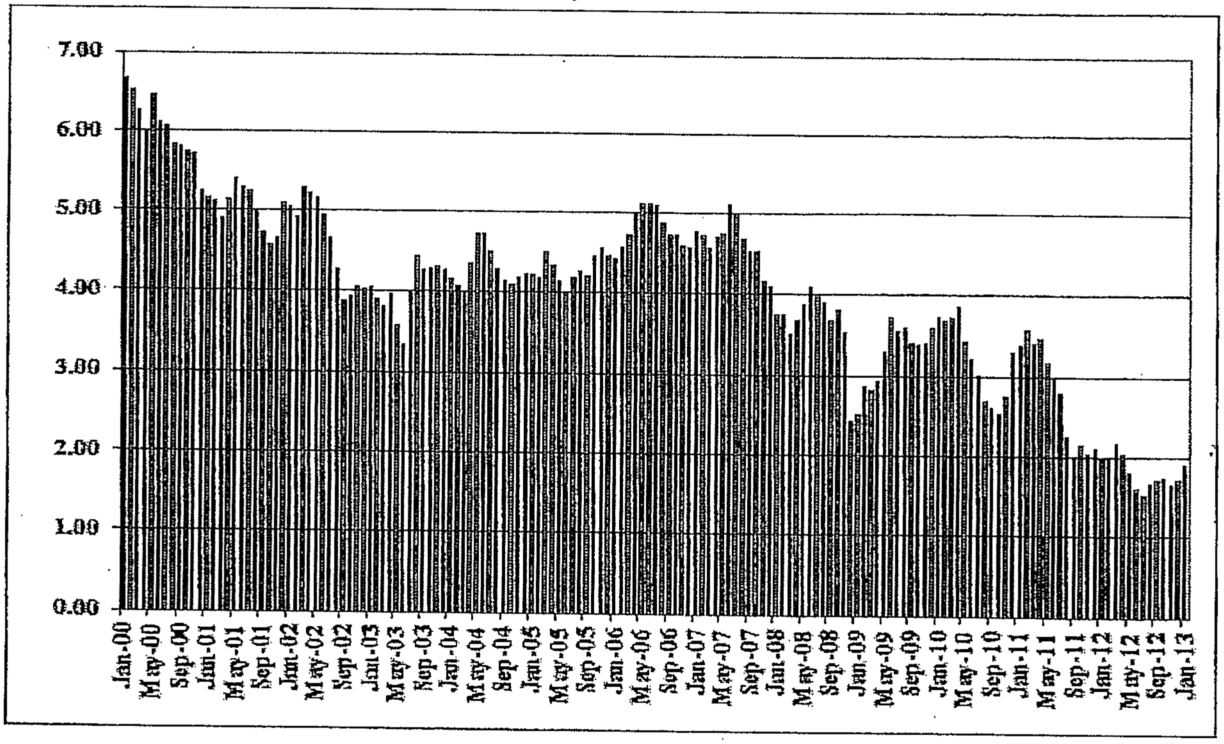
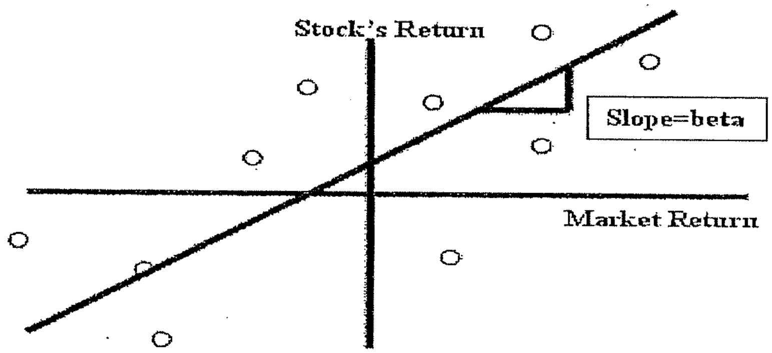


Exhibit JRW-11

Panel A
Betas

Calculation of Beta



Water Proxy Group

Company	Beta
American States Water Co. (NYSE-AWR)	0.70
American Water Works Co., Inc. (NYSE-AWK)	0.65
Aqua America, Inc. (NYSE-WTR)	0.60
Artesian Resources Corp. (NDQ-ARTNA)	0.55
California Water Service Group (NYSE-CWT)	0.65
Connecticut Water Service, Inc. (NDQ-CTWS)	0.75
Middlesex Water Company (NDQ-MSEX)	0.70
SJW Corporation (NYSE-SJW)	0.85
York Water Company (NDQ-YORW)	0.70
Mean	0.68
Median	0.70

Data Source: *Value Line Investment Survey, 2013.*

Gas Proxy Group

Company	Beta
AGL Resources Inc. (NYSE-ATG)	0.75
Atmos Energy Corporation (NYSE-ATO)	0.70
Laclede Group, Inc. (NYSE-LG)	0.55
Northwest Natural Gas Co. (NYSE-NWN)	0.60
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	0.65
South Jersey Industries, Inc. (NYSE-SJI)	0.65
Southwest Gas Corporation (NYSE-SWX)	0.75
WGL Holdings, Inc. (NYSE-WGL)	0.65
Mean	0.66
Median	0.65

Data Source: *Value Line Investment Survey, 2013.*

Exhibit JRW-11
Risk Premium Approaches

	Historical Ex Post Returns	**Surveys**	**Expected Return Models and Market Data**
Means of Assessing The Market Risk Premium	Historical Average Stock Minus Bond Returns	Surveys of CFOs, Financial Forecasters, Companies, Analysts on Expected Returns and Market Risk Premiums	Use Market Prices and Market Fundamentals (such as Growth Rates) to Compute Expected Returns and Market Risk Premiums
Problems/Debated Issues	Time Variation in Required Returns, Measurement and Time Period Issues, and Biases such as Market and Company Survivorship Bias	Questions Regarding Survey Histories, Responses, and Representativeness Surveys may be Subject to Biases, such as Extrapolation	Assumptions Regarding Expectations, Especially Growth

Source: Adapted from Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

Exhibit JRW-11

Kentucky-American Water Company
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Median
Historical Risk Premium										
	Ibbotson	2013	1926-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.70%	
					Geometric				4.10%	
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Damodoran	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.70%	
					Geometric				5.10%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Steunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	Median									5.50%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	Best & Byrne	2001								
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns,, & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Damodoran	2013	Projection	Fundamentals - Implied from FCF to Equity Model					5.43%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Years	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Years	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	Median									3.75%
Surveys										
	Survey of Financial Forecasters	2013	10-Year Projection	About 50 Financial Forecasters					2.30%	
	Duke - CFO Magazine Survey	2013	10-Year Projection	Approximately 350 CFOs					4.50%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%	5.37%	5.37%	
	Fernandez - Academics	2012	Long-Term	Survey of Academics					5.60%	
	Fernandez - Analysts	2012	Long-Term	Survey of Analysts					5.00%	
	Fernandez - Companies	2012	Long-Term	Survey of Companies					5.50%	
	Median									5.19%
Building Block										
	Ibbotson and Chen	2012	1926-2011	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			5.99%	4.95%	
					Geometric			3.91%		
	Woolridge		2013	Current Supply Model (D/P & Earnings Growth)					4.40%	
	Median									4.68%
Mean										4.78%
Median										4.93%

Exhibit JRW-11

Kentucky-American Water Company
Capital Asset Pricing Model
Equity Risk Premium

Summary of 2010-13 Equity Risk Premium Studies

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2013	1926-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.70%	
					Geometric				4.10%	
	Median									4.90%
Ex Ante Models (Puzzle Research)										
	Damodaran	2013	Projection	Fundamentals - Implied from FCF to Equity Model					5.43%	
	Median									5.43%
Surveys										
	Survey of Financial Forecasters	2013	10-Year Projection	About 50 Financial Forecasters					2.30%	
	Duke - CFO Magazine Survey	2013	10-Year Projection	Approximately 350 CFOs					4.50%	
	Fernandez - Academics	2012	Long-Term	Survey of Academics					5.60%	
	Fernandez - Analysts	2012	Long-Term	Survey of Analysts					5.00%	
	Fernandez - Companies	2012	Long-Term	Survey of Companies					5.50%	4.75%
Building Block										
	Ibbotson and Chen	2012	1926-2011	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			5.99%	4.95%	
					Geometric			3.91%		
	Woolridge		2013	Current Supply Model (D/P & Earnings Growth)					4.40%	
	Median									4.68%
Mean										4.94%
Median										4.83%

Authorized ROEs for Publicly-Held Water Companies

	Authorized ROE	Date
American States Water	9.99%	Nov-11
American Water Works	9.61%	
Aqua America, Inc.	10.33%	
Artesian Resources Corp.	10.00%	Sep-09
California Water Service Group	9.99%	Nov-11
Connecticut Water Services, Inc.	9.75%	Jul-10
Middlesex Water Company	10.15%	
SJW Corp.	9.99%	Nov-11
York Water Company	NA	
Average	9.98%	

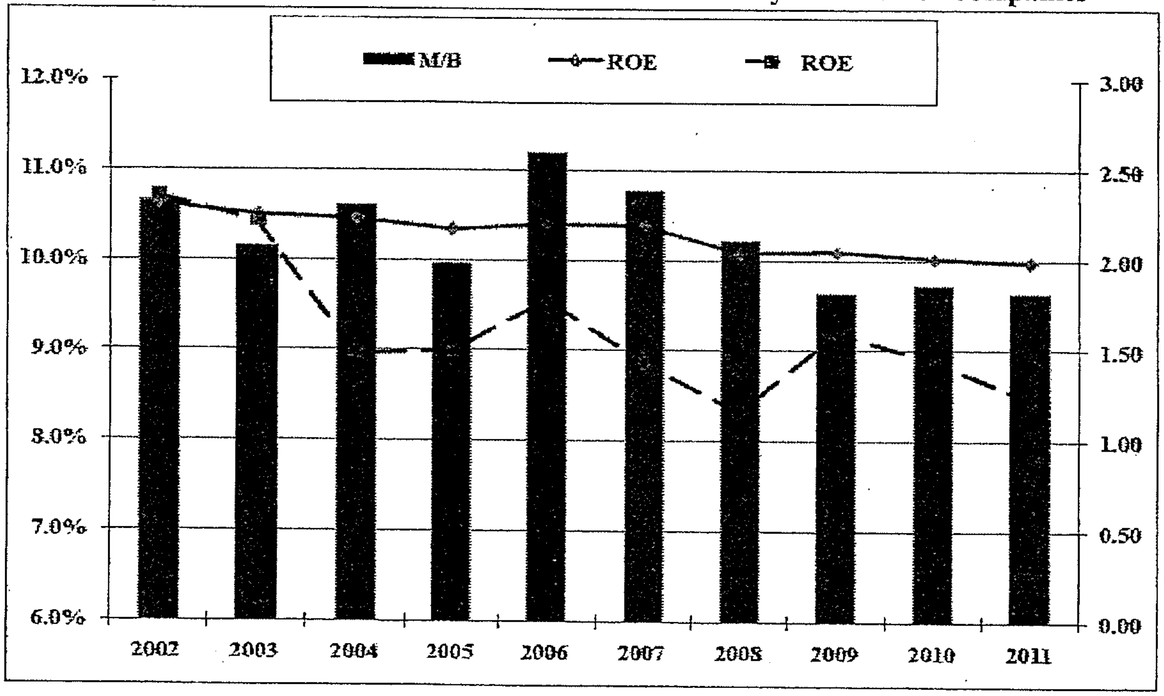
Data Source: *AUS Utility Reports, March, 2013.*

Panel A
Authorized and Earned ROEs and M/B Ratios for Publicly-Held Water Companies

Year	Authorized ROE	Earned ROE	M/B
2002	10.63%	10.72%	2.33
2003	10.50%	10.44%	2.07
2004	10.46%	8.98%	2.31
2005	10.35%	9.00%	1.98
2006	10.40%	9.57%	2.59
2007	10.39%	8.86%	2.39
2008	10.08%	8.33%	2.11
2009	10.09%	9.20%	1.82
2010	10.02%	8.89%	1.87
2011	9.98%	8.47%	1.82

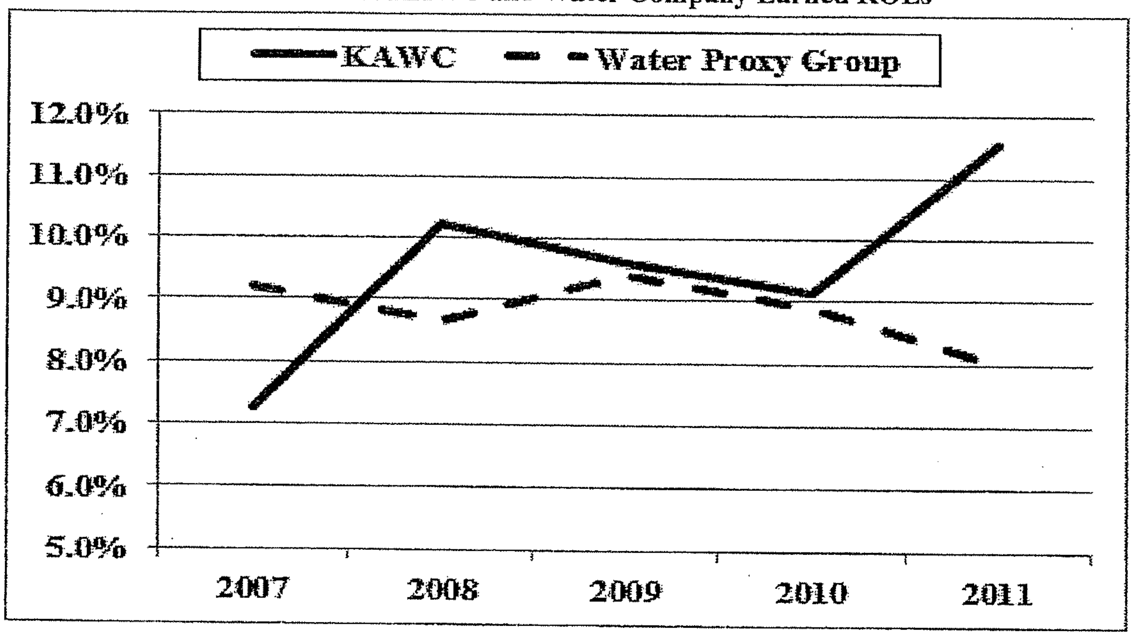
Data Source: *AUS Utilities Report, Value Line Investment Survey*

Panel B
Summary of Authorized ROEs and M/B Ratios for Publicly-Held Water Companies



Data Source: *AUS Utilities Report, Value Line Investment Survey*

Assessment of KAWC and Water Company Earned ROEs



Data Sources: *Value Line Investment Survey* and KAWC response to AG DR 1-28.
KAWC's 2012 ROE was 9.21%. The earned ROEs for the water companies are not yet available.

Exhibit JRW-13

Kentucky-American Water Company
Cost of Capital

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	2.04%	0.81%	0.02%
Long-Term Debt	52.04%	6.14%	3.20%
Preferred Stock	1.17%	8.52%	0.10%
Common Equity	44.75%	10.90%	4.88%
Total Capital	100.00%		8.19%

Panel A

Summary of Dr. Vander Weide's Equity Cost Rate Approaches and Results

Approach	Cost of Equity
DCF - Water	10.50%
DCF - LDC	10.40%
Ex Ante Risk Premium	11.40%
Ex Post Risk Premium	10.80%
Equity Cost Rate Range	10.40%-11.4%

Panel B

Summary of Dr. Vander Weide's DCF - Water Results

	Utility Proxy Group
Average Adjusted Dividend Yield*	3.25%
Growth**	7.25%
DCF Result	10.50%

* Includes adjustments for quarterly payments and flotation costs
** Expected EPS Growth from IBES and *Value Line*

Summary of Dr. Vander Weide's DCF - Gas Results

	Utility Proxy Group
Average Adjusted Dividend Yield*	4.80%
Growth**	5.60%
DCF Result	10.40%

* Includes adjustments for quarterly payments and flotation costs
** Expected EPS Growth from IBES and and not *Value Line*

Panel C

Summary of Dr. Vander Weide's Ex Ante Risk Premium Results

	Ex Ante Risk Premium
'A' Rated PU Yield	6.60%
Ex Ante Risk Premium*	4.80%
Equity Cost Rate	11.40%

* Flotation Cost included in risk premium

Panel D

Summary of Dr. Vander Weide's Ex Post Risk Premium Results

	Ex Ante Risk Premium
Projected 'A' Rated PU Yield	6.60%
Historic Risk Premium*	4.05%
Equity Cost Rate	10.65%
Flotation Cost Adjustment	0.17%
Adjusted CAPM Result	10.82%

* Midpoint of 3.8% and 4.3%

Panel E

Summary of Dr. Vander Weide's Historical CAPM Results

	Utility Proxy Group
Risk-Free Rate	5.11%
Beta	0.65
Equity Risk Premium	6.62%
CAPM Result	9.41%
Flotation Cost Adjustment	0.17%
Adjusted CAPM Result	9.58%

Panel F

Summary of Dr. Vander Weide's Expected CAPM Results

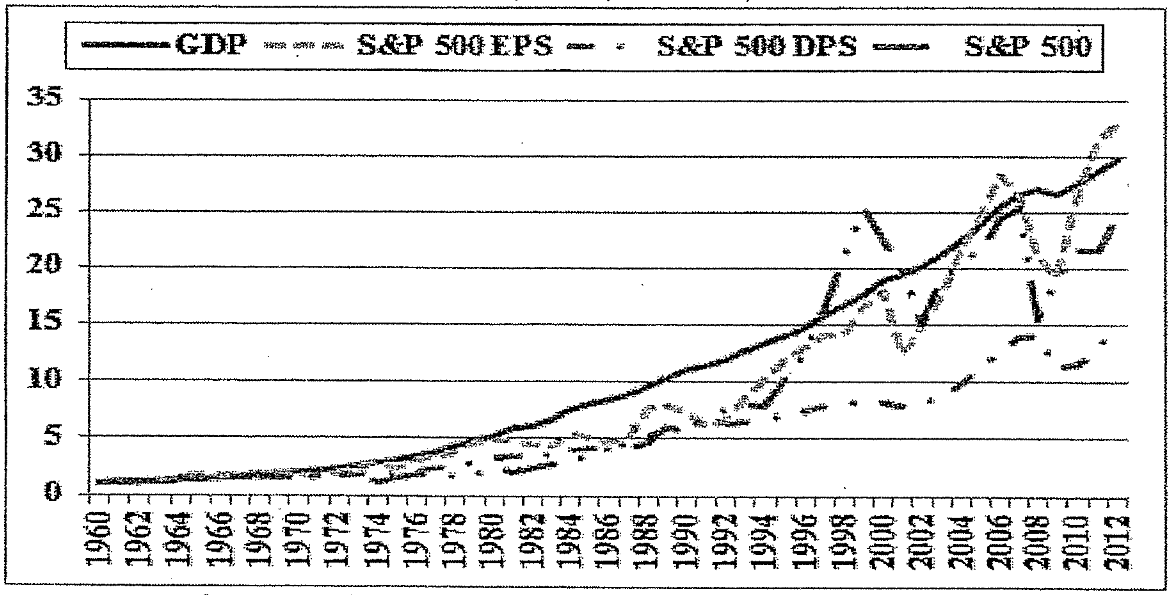
	Utility Proxy Group
Risk-Free Rate	5.11%
Beta	0.65
Equity Risk Premium	7.49%
CAPM Result	9.98%
Flotation Cost Adjustment	0.17%
Adjusted CAPM Result	10.15%

Growth Rates
GDP, S&P 500 Price, EPS, and DPS

	GDP	S&P 500	Earnings	Dividends	
1960	526.4	58.11	3.10	1.98	
1961	544.8	71.55	3.37	2.04	
1962	585.7	63.10	3.67	2.15	
1963	617.8	75.02	4.13	2.35	
1964	663.6	84.75	4.76	2.58	
1965	719.1	92.43	5.30	2.83	
1966	787.7	80.33	5.41	2.88	
1967	832.4	96.47	5.46	2.98	
1968	909.8	103.86	5.72	3.04	
1969	984.4	92.06	6.10	3.24	
1970	1038.3	92.15	5.51	3.19	
1971	1126.8	102.09	5.57	3.16	
1972	1237.9	118.05	6.17	3.19	
1973	1382.3	97.55	7.96	3.61	
1974	1499.5	68.56	9.35	3.72	
1975	1637.7	90.19	7.71	3.73	
1976	1824.6	107.46	9.75	4.22	
1977	2030.1	95.10	10.87	4.86	
1978	2293.8	96.11	11.64	5.18	
1979	2562.2	107.94	14.55	5.97	
1980	2788.1	135.76	14.99	6.44	
1981	3126.8	122.55	15.18	6.83	
1982	3253.2	140.64	13.82	6.93	
1983	3534.6	164.93	13.29	7.12	
1984	3930.9	167.24	16.84	7.83	
1985	4217.5	211.28	15.68	8.20	
1986	4460.1	242.17	14.43	8.19	
1987	4736.4	247.08	16.04	9.17	
1988	5100.4	277.72	24.12	10.22	
1989	5482.1	353.40	24.32	11.73	
1990	5800.5	330.22	22.65	12.35	
1991	5992.1	417.09	19.30	12.97	
1992	6342.3	435.71	20.87	12.64	
1993	6667.4	466.45	26.90	12.69	
1994	7085.2	459.27	31.75	13.36	
1995	7414.7	615.93	37.70	14.17	
1996	7838.5	740.74	40.63	14.89	
1997	8332.4	970.43	44.09	15.52	
1998	8793.5	1229.23	44.27	16.20	
1999	9353.5	1469.25	51.68	16.71	
2000	9951.5	1320.28	56.13	16.27	
2001	10286.2	1148.09	38.85	15.74	
2002	10642.3	879.82	46.04	16.08	
2003	11142.2	1111.91	54.69	17.88	
2004	11853.3	1211.92	67.68	19.41	
2005	12623.0	1248.29	76.45	22.38	
2006	13377.2	1418.30	87.72	25.05	
2007	14028.7	1468.36	82.54	27.73	
2008	14291.5	903.25	65.39	28.05	
2009	13973.7	1115.10	59.65	22.31	
2010	14498.9	1257.64	83.66	23.12	
2011	15075.7	1257.60	97.05	26.02	**Average**
2012	15681.5	1426.19	102.47	30.44	
Growth Rates	**6.74**	**6.35**	**6.96**	**5.39**	**6.36**

Data Sources: GDPA - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

Long-Term Growth of GDP, S&P 500, S&P 500 EPS, and S&P 500 DPS



	GDP	S&P 500	S&P 500 EPS	S&P 500 DPS
Growth Rates	6.74%	6.35%	6.96%	5.39%

Panel A
Historic GDP Growth Rates

10-Year Average	4.0%
20-Year Average	4.6%
30-Year Average	5.1%
40-Year Average	6.6%
50-Year Average	6.8%

Calculated using GDP data on Page 1 of Exhibit JRW-14

Panel B
Projected GDP Growth Rates

	Time Frame	Projected Nominal GDP Growth Rate
Congressional Budget Office	2013-2023	4.6%
Survey of Financial Forecasters	Ten Year	4.8%
Energy Information Administration	2011-2040	4.5%

Sources:
http://www.cbo.gov/ftpdocs/120xx/doc12039/01-26_FY2013Outlook.pdf page XIII
http://www.eia.gov/forecasts/aeo/tables_ref.cfm Table 20
http://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2013/survq113.cfm

Commonwealth of Kentucky
Before the Public Service Commission

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN	)
WATER COMPANY FOR AN ADJUSTMENT OF	) Case No. 2012-00520
RATES SUPPORTED BY A FULLY FORECASTED	)
TEST YEAR	)

AFFIDAVIT OF DR. J. RANDALL WOOLRIDGE

Commonwealth of Pennsylvania)
)
County of Centre)

Dr. J. Randall Woolridge, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Exhibits and Appendices attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Dr. J. Randall Woolridge

Dr. J. Randall Woolridge

SUBSCRIBED AND SWORN to before me this 1st day of April, 2013.

Mary L. Hart

NOTARY PUBLIC

My Commission Expires:

NOTARIAL SEAL
MARY L HART
Notary Public
STATE COLLEGE BORO., CENTRE COUNTY
My Commission Expires Aug 25, 2013

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF COLUMBIA GAS	)	
OF KENTUCKY, INC. FOR AN ADJUSTMENT	)	CASE NO. 2013-00167
OF RATES FOR GAS SERVICE	)	

AFFIDAVIT OF FRANK RADIGAN

State of New York)
)
)

Frank Radigan, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Frank Radigan

SUBSCRIBED AND SWORN to before me this 10 day of September, 2013.

NOTARY PUBLIC

My Commission Expires: 11/8/2014

KONSTANTIN PODOLNY
Notary Public, State of New York
Qualified in Albany County
No. 02PO6230727
Commission Expires Nov. 08, 2014

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

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

PUBLIC VERSION
DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

SEPTEMBER 11, 2013

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, VA 23235.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I have provided testimony concerning class cost of service and rate design in several rate cases before this Commission including Columbia's last general rate case, as well as various cases filed by Louisville Gas & Electric, Kentucky Utilities, Duke Energy, Blue Grass Electric Cooperative, and Owen Electric Cooperative.

Q. HAVE YOU PARTICIPATED IN OTHER COLUMBIA GAS REGULATORY PROCEEDINGS?

A. Yes. I have participated and provided expert testimony in numerous other Columbia Gas rate cases in Virginia (Columbia Gas of Virginia); Pennsylvania (Columbia Gas of Pennsylvania); Ohio (Columbia Gas of Ohio), and Maryland (Columbia Gas of Maryland).

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

A. Technical Associates, Inc. has been retained by the Kentucky Office of the Attorney General ("AG") to evaluate the reasonableness of Columbia Gas of Kentucky's ("Columbia" or "Company") natural gas class cost of service studies, proposed distribution of revenues by customer class and residential rate design. The purpose of my direct testimony is to provide comments regarding my analysis of the Company's proposals and to present my findings and recommendations based on the studies I have undertaken in this matter.

Q. PLEASE PROVIDE A SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS.

A. I have conducted a detailed examination of the Company's class cost allocation studies and have concluded that they do not produce credible results and should not be relied upon in this proceeding. I have also investigated the discounted rates offered to certain large customers and have determined that no discounts are justified for three of these large customers. To the extent the Company continues to offer such unjustified discounts to these customers, these discounts should be funded by shareholders and not by captive ratepayers. With respect to class revenue increase allocations, I recommend an across-the-board (equal percentage) increase to all rate schedules after consideration of the disallowance of unjustified discounts to certain customers. Finally, I recommend the rejection of the Company's proposed Revenue Normalization Adjustment ("RNA") Rider and recommend a residential customer charge of no more than $14.00 per month.

II. CLASS COST OF SERVICE

A. Concepts and Methods

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, Columbia has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS. The costs are jointly incurred to serve all or most customers; therefore, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> "But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1] 324 U.S. 581, 65 S. Ct. 829.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS LOCAL DISTRIBUTION COMPANIES ("LDCs").

A. As I mentioned earlier, the majority of a LDCs' plant investment serves customers in a joint manner. In this regard, the LDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. Customers (or customer groups) tend to vary greatly in the amount of service required throughout the year such that there are small usage and large usage customers. Therefore, differences in usage should be considered.

Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. WITH REGARD TO UTILITIES GENERALLY, AND NATURAL GAS LDC'S SPECIFICALLY, ARE THERE A COMMON SET OF EXTERNAL FACTORS, OR DRIVERS, USED IN VIRTUALLY EVERY CCOSS?

A. Virtually every utility cost allocation study rests on the analysts' selection of three primary external (exogenous) allocation factors: number of customers; peak demand; and, annual (average day) usage.[2] From these three exogenous factors, a host of internally generated allocation factors are developed based on previously allocated plant and expenses. In this regard, it is important to understand that the relative relationship across classes between these external allocators can be dramatically different.

Q. WITH RESPECT TO COLUMBIA, WHAT ARE THE RELATIVE CLASS RELATIONSHIPS OF THESE THREE PRIMARY ALLOCATION FACTORS?

A. The following table shows the relative amounts (percentages) of the three primary external allocation factors using the Company's class definitions:

[2] It should be noted that "weighted" customer counts are often used for certain plant and expense accounts.

TABLE 1

Allocation Factor	Class				
	Resid.	GS-Other	IUS	ML/SC	DS/IS
Customers	89.568%	10.372%	0.002%	0.005%	0.053%
Annual MCF	26.363%	17.819%	0.046%	15.615%	40.157%
Peak Demand (Design Day)	61.131%	35.115%	0.088%	1.369%	2.297%

As can be seen above, there is a vast difference in the relativities of these external allocation factors, such that the selection of a particular allocator will significantly affect the assignment of costs across the classes.

Q. WITH REGARD TO NATURAL GAS LDCs, IS THERE ANY ASPECT OF CLASS COST ALLOCATIONS THAT TENDS TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. For virtually every natural gas LDC, the largest single rate base item (account) is distribution mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains. As such, the methods and approaches used to allocate distribution mains to classes are usually by far the most important (in terms of class rate of return ["ROR"] results) and tend to be the most controversial.

Q. BEFORE YOU DISCUSS THE VARIOUS METHODS AND APPROACHES USED TO ALLOCATE MAINS, ARE THERE ANY MEASUREMENT CONCEPTS THAT ARE CRITICAL TO FULLY UNDERSTAND?

A. Yes. Most public utility costing studies consider some form of peak demand. For natural gas LDC's, peak demand is usually expressed on a peak day basis. However, there are several concepts and definitions relating to peak day demand that should clearly be understood. The first set of concepts and definitions concern actual and potential (theoretical) peak day demands. Actual peak day demands are just that: the actual maximum demands measured (or estimated) over some pre-defined period; e.g., a test year. Potential, or theoretical, peak day demands are referred to as "design day" demands and reflect the estimated demands on the coldest day realistically possible for a particular geographic service area.[3]

The next set of definitional "peak day demands" relates to the timing, or "coincidence" of demands, between various user groups or classes. Class coincident peak demands are defined as class usage on the day of the system peak (whether on an actual or design day basis). Class non-coincident peak day demands relate to each class's peak day usage, regardless of when the entire system peaks. Because of the highly weather sensitive nature of total LDC systems, class coincident and non-coincident peak day demands are usually on the same day for the residential and commercial classes. For some LDC's, the industrial non-coincident peak day demand may not coincide with the system (coincident) peak day usage depending on scheduling and production outputs of these industrial customers.

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[3] Residential and commercial natural gas usage tends to be extremely weather sensitive, while industrial usage may or may not be weather sensitive depending on the use of gas by these customers for space heating and industrial processes.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

A. While a myriad of cost allocation methods and approaches have been developed, three (3) *methods* predominate in the natural gas LDC industry: "peak responsibility," "Peak and Average" or "Demand/Commodity," and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing mains investments. There are three (3) *criteria* generally considered when *selecting* a mains cost allocation method: peak demand (whether coincident, non-coincident, actual or design day); annual (average day) usage; and, number of customers. Because a LDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of mains investment.[4] Annual (or average day) throughput is also often used to allocate mains as this factor reflects the utilization of a utility's mains investment. Number of customers is also sometimes considered when allocating mains. That is, customer counts by class serve as a basis for allocation mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these

[4] Embedded cost allocations are directly only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

The three most common natural gas LDC cost allocation methods are: the "peak responsibility" method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate mains; the "Peak and Average" or "Demand/Commodity" approach in which both peak day and annual (average day) throughput is reflected within the allocation of mains;[5] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. The second approach used to classify and allocate mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" Main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is

[5] Under the Peak and Average or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

multiplied by the total system footage and is then divided by total mains investment to arrive at a customer weighting.

Q. WHICH METHOD, OR METHODS, DID THE COMPANY USE TO ALLOCATE COSTS TO CUSTOMER CLASSES FOR THIS CASE?

A. Company witness Russell Feingold conducted two different cost allocation studies: one using the Customer/Demand method and the other using the Peak and Average approach to allocate mains.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The Peak and Average approach is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. WHAT RATIONALE IS USED TO ALLOCATE MAINS INVESTMENT, AT LEAST PARTIALLY, BASED ON CUSTOMER COUNTS?

A. I am aware of two rationales, or arguments, used to advocate the allocation of natural gas distribution mains based partially on number of customers. While the conceptual argument has no economic or practical logic in my opinion, the second rationale may produce reasonable results in some instances, but is rarely applicable to natural gas LDC's.

The first rationale used by some analysts is that, because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of a physical "plumbing" is required to deliver natural gas to each and every end-user.[6] Indeed, this is the very purpose of the distribution system. However, no customer connects to a LDC system simply to be connected but never utilize natural gas, nor do LDC's haphazardly install natural gas mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a LDC's distribution mains required to simply connect customers.

The second rationale used to consider number of customers within the allocation of mains relates to customer densities and differences in the mix of customers (by class) throughout a utility's service area. Possibly the best way to explain why customer densities may be relevant in the assignment of distribution costs to individual classes is by way of example. Consider two different utilities: a rural electric utility with urban, suburban, and rural service areas and another utility with only urban and suburban customers. With respect to the electric utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile

[6] If natural gas was delivered to end-users in tanks (such as done with propane), there would be no distribution system, or Mains to allocate.

basis for the urban/suburban utility. With respect to the utility with a rural service area, such an allocation based on usage or demand may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, some cost studies classify distribution plant as partially demand-related and partially customer-related.

Q. IN THE ABOVE EXAMPLE, YOU REFERRED TO ELECTRIC UTILITIES INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?

A. Yes. Although the concepts are the same between electric and natural gas distribution facilities (e.g., conductors are synonymous with mains), electric utilities are *required* to serve rural (sparsely populated) areas. Such requirements, however, are **not** in place for natural gas LDCs. Moreover, electric utilities are required to connect all consumers regardless of density or usage. Such is not the case for natural gas LDCs, as their tariffs allow the utility to only connect those customers in areas with sufficient customer densities and usage.

As such, and as a general matter, a Customer/Demand classification of *electric* distribution facilities may be appropriate given the characteristics of a utility's service area, but are rarely appropriate for *natural gas* LDCs with more densely populated service areas that are not required to serve all potential residences and businesses.

Q. HOW APPROPRIATE IS A CUSTOMER/DEMAND SEPARATION FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

A. First and foremost, the classification of distribution plant as partially customer, and partially demand-related results from the view that the assignment of these plant items to classes based solely on a demand allocator would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees." When classifying individual accounts within distribution plant, analysts sometimes do not consider how a distribution system is designed and connected.

There are several major factors the analyst should keep in mind when classifying natural gas distribution plant. First is the fact that purchasing economies are usually present. For example, there are many types and sizes of pipe manufactured. However, due to purchasing economies, a utility may purchase only a few different sizes of pipe. This will result in some "over capacity," however, the total installed cost will be less than if every segment of the system is optimally sized. Second, most components of the distribution system are somewhat oversized for other reasons, such as pressure equalization, safety, reliability, and growth uncertainty. Third, historical asset records reflecting capitalized labor and material costs by size and type of investment are far from perfect.[7] These asset records are the underlying source for conducting minimum size and zero-intercept studies. Fourth, and particularly relevant to most natural gas LDC's including Columbia, is that it generally costs significantly more to install and maintain mains pipes in more urban (densely populated) areas of the Company's service area that in its more suburban (less densely populated) areas. This is because of the infrastructure within, and adjacent to, mains rights-of-way as well as the predominant types of pipe used in various areas. In the more urban parts of a service area, mains are generally

[7] Reasons for less than perfect record keeping include: the loss of data over time, the changing needs of recordkeeping by a Company, data processing limitation, different record keeping practices and detail by companies prior to mergers/acquisition by other companies.

buried under roads and sidewalks creating significantly higher costs than suburban areas in which a single trench along a road-side is often the only thing necessary. Moreover, due to the size of pipes required as well as safety needs, larger pipes in the suburban areas tend to be steel as opposed to much cheaper plastic pipe.

Although these factors are reflective of how distribution systems are actually installed and operated, classification studies do not account for these factors. In fact, the presence of these factors can seriously skew the results of such studies.

Q. SHOULD PEAK DAY DEMANDS BE THE ONLY CONSIDERATION WHEN ALLOCATING NATURAL GAS DISTRIBUTION MAINS?

A. No. Perhaps the most fundamental aspect of cost allocation is the desire to reasonably assign costs (plant and expenses) based on cost causation. As indicated earlier, while it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. An LDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If Columbia's (or any natural gas LDC's) customers only demand gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, Columbia's customers' demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Q. IS COLUMBIA'S "MAINS EXTENSION" POLICY CONSISTENT WITH THE REALITY THAT CUSTOMERS UTILIZE NATURAL GAS THROUGHOUT THE YEAR AND NOT ON JUST A SINGLE DAY?

A. Yes. When Columbia evaluates a Main extension proposal or project, it considers the maximum load that will be placed on the extension as well as the annual usage of the Main extension in determining customer (developer) contribution requirements.

Q. EVEN THOUGH MAINS ARE INSTALLED TO MEET THE NATURAL GAS ENERGY NEEDS OF CUSTOMERS THROUGHOUT THE YEAR AND IT WOULD BE PROHIBITIVELY EXPENSIVE TO SERVE A CUSTOMER FOR ONLY ONE DAY PER YEAR, DOES IT COST MORE TO INSTALL A MAIN WITH HIGHER PEAK DEMANDS PLACED UPON IT THAN ANOTHER SEGMENT WITH LOWER PEAK DAY DEMAND REQUIREMENTS?

A. While this is correct as a broadly general statement, there is not a direct and linear relationship between peak demands (capacity requirements) and costs. This is the most important concept. That is, if one where to consider allocating the cost of mains based on the physical relationships of peak day demand (load) one must evaluate whether costs increase proportionally and in a linear manner with peak load. In reality, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for a higher capacity pipe (to meet these additional costs) may be higher but is not double that of the lower capacity main. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand) because it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads (demand), system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a LDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the *capacity* of pipes increases by a factor of exactly 4 to 1 as the *diameter* of pipe increases.[8] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[9]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. This fact is most relevant for cost allocation purposes for older LDC's with large mains replacement programs, such as Columbia. With increases in materials, technology, and pipe coupling improvements, we are seeing that LDC's are replacing their systems with *smaller* plastic pipes operated at *higher* pressures. In response to AG 1-292, Columbia indicates that a 2-inch plastic pipe operating at 60 pounds per square inch gauge ("psig") has approximately 3.6 times the capacity of a 4-inch plastic line operating at low pressures

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8 The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

9 The cost of Mains investment reflects the cost of capitalized labor to install the Main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

(less than 1psig). Because the allocation of mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of mains. This assumption is clearly not accurate.

Q. SINCE THERE IS NOT A DIRECT AND LINEAR RELATIONSHIP BETWEEN PEAK LOAD REQUIREMENTS AND THE COST OF MAINS, IS THERE A COST ALLOCATION METHOD THAT REASONABLY REFLECTS THE COST CAUSATION OF MAINS?

A. Yes. When properly applied, the Peak and Average (Demand/Commodity) method reasonably and fairly models the economies of scale reflected in mains investment. If all customers (and classes) demanded and utilized natural gas at a consistent rate throughout the year, Columbia's LDC system would be comprised of smaller size mains. Obviously, such is not the case in that Columbia's peak (design day) demands are about 3.92 times that of its average day firm service demands.[10] Even though the increased capacity required to serve design day peak loads is almost four times that required for average day loads, the actual cost of mains is much smaller than this almost 4 to 1 relationship. In fact, it is apparent that the diameters of Columbia's mains are about twice as large as would be required under constant load conditions. However, the incremental cost of this additional capacity (to serve design day loads

[10] Company responses to AG 1-266 and 1-272. Total design day demand is 325,500 MCF, whereas average day demand is 83,139 MCF.

versus average day loads) is less than a factor of two. This indicates that a cost allocation method which allocates about half of Columbia's mains costs based on average demand and the remaining half on peak demand serves as a reasonable proxy for cost causation and fairly assigns class cost responsibility. To summarize, the allocation of mains solely on peak demands does not reflect cost causation due to the economies of scale present in meeting the capacity (design day) needs of the company's distribution system; i.e., as peak demand increases, costs increase at a decreasing rate.

B. Columbia Specific Class Cost of Service

Q. HOW DID MR. FEINGOLD DEFINE THE VARIOUS CLASSES FOR PURPOSES OF HIS CCOSS?

A. Mr. Feingold has separated Columbia's total jurisdictional business into five classes as follows:

GS-Res – residential sales and transportation service;

GS-Other – small volume commercial and industrial sales and transportation service;

IUS – wholesale distribution service;

ML/SC – "mainline" plus "special contract" service; and

DS/IS – large commercial and industrial transportation plus interruptible service.

Q. ARE THESE CLASS DEFINITIONS, OR CATEGORIES, APPROPRIATE FOR COSTING PURPOSES?

A. Not entirely. Columbia has numerous specific rate schedules available to customers for sales and transportation service. As such, each "class" reflects the combination of various specific rate schedules. With regard to the GS-Res, GS-Other, and IUS classes, Mr. Feingold's definition and grouping of rate schedules is reasonable and appropriate for cost allocation purposes. However, with regard to the "ML/SC" and "DS/IS" classes, these should be broken up (disaggregated) into separate classes.

Q. PLEASE EXPLAIN WHY THE "ML/SC" CLASS SHOULD BE FURTHER SEPARATED?

A. It is not appropriate to combine various rate schedules into a single ML/SC "class" because the usage characteristics, terms of service, and cost relationships are significantly different for these various customers. Mainline Service ("ML") is a specific rate that is available only to those customers located adjacent to an interstate pipeline and do not rely on Columbia's distribution mains. Special Contract ("SC") customers do utilize Columbia's distribution system but receive a negotiated, discounted, rate.[11] Because of the significantly different characteristics of Mainline and Special Contract (discounted rate) customers, these should be separated into two separate classes.

Q. WHY DID MR. FEINGOLD COMBINE THE SIGNIFICANTLY DIFFERENT MAINLINE AND DISCOUNTED RATE CUSTOMERS INTO ONE CLASS?

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[11] There are two "Special Contract" customers that are also "Mainline" customers. These two special Mainline customers pay **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** For cost allocation purposes, the two Special Contract, Mainline customers should be treated as, and included in, the Mainline class.

A. Although combining these two distinctly different groups into a single class is illogical, it appears that the only reason Mr. Feingold combined Mainline and Special Contract customers is because he allocated (assigned) no distribution mains cost responsibility to this combined class.

Q. IS IT APPROPRIATE TO ASSIGN NO MAINS COST RESPONSIBILITY TO THIS COMBINED GROUPING OF CUSTOMERS?

A. No. While I agree that Mainline customers should not be allocated any distribution mains costs, this is not true for the Special Contract customers.[12] The three large "Special Contract" customers rely on Columbia's distributions mains like all other traditional firm commercial and industrial customers. The only difference being that these four accounts (3 customers) receive a discounted rate below that of the Commission authorized full tariff. However, and as mentioned earlier, even though these Special Contract rate customers rely upon distribution mains and demand the same services as other firm customers, Mr. Feingold did not assign any cost responsibility to these discounted rate customers.

Q. BEFORE WE CONTINUE, DOES MR. FEINGOLD'S FAILURE TO ASSIGN ANY DISTRIBUTION MAINS COST RESPONSIBILITY TO SPECIAL CONTRACT CUSTOMERS HAVE A COMPOUND EFFECT ON THE TOTAL COSTS ASSIGNED TO THIS GROUP?

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[12] This statement refers to the four accounts (3 customers) that utilize Columbia's distribution mains and excludes three accounts (2 customers) that are "Mainline" customers and pay **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

A. Yes. Distribution mains represents Columbia's single largest rate base item (plant investment). As such, the allocation of distribution mains investment (or lack thereof) has a material impact on each class's total allocated cost of service. However, there is a far reaching implication regarding the allocation of this one plant account. That is, many other rate base and expense accounts are allocated totally, or partially based on, previously allocated distribution mains investment. As such, any errors or bias within the allocation of Account 376 (Distribution Mains Plant) have far reaching impacts on the total costs allocated to every class of service.

Q. FROM A CONCEPTUAL STANDPOINT, DOES IT APPEAR THAT MR. FEINGOLD WOULD AGREE WITH YOU THAT THE SPECIAL CONTRACT CUSTOMERS SHOULD BE SEPARATED FROM MAINLINE CUSTOMERS AND ALLOCATED A REASONABLE LEVEL OF MAINS COST?

A. Yes. On page 16 of his direct testimony, Mr. Feingold opines that "it is important to recognize the cost causative characteristics of the cost elements which are allocated within any class cost of service study." He then states that any cost allocation study should provide "recognition of cost causality as opposed to value of service."

Q. WHAT ARE THE IMPLICATIONS OF MR. FEINGOLD'S COMBINATION OF THE MAINLINE AND SPECIAL CONTRACT CUSTOMERS INTO A SINGLE CLASS AND NOT ASSIGNED ANY MAINS COSTS TO THIS GROUP?

A. There are two implications. First, by combining two distinctly different types of service, it is not possible to evaluate the reasonableness of the rate charged to each of the two distinctly different groups of customers. Second, and more importantly, is the fact that Mr. Feingold's failure to allocate any mains costs to the Special Contract customers means that he has over assigned costs to all other customers classes, and therefore, results in a clear cost allocation bias. The topic of "special" or discounted rate customers will be discussed in much more detail later in my testimony.

Q. PLEASE EXPLAIN WHY THE "DS/IS" CLASS SHOULD BE FURTHER SEPARATED.

A. Mr. Feingold's "DS/IS" class is comprised of customers taking service under large transportation delivery service ("DS") as well as those under interruptible service ("IS"). Based on my reading of the tariff, Rate DS is firm service whereas Rate IS is subject to curtailment during periods of peak demand. Although Columbia has sufficient capacity such that it has not interrupted any customers in at least several years, service under Rate IS is inferior to firm service such as DS. Because these rates reflect distinctly different service, they should be separated for costing purposes.

Q. WHY IS IT YOUR UNDERSTANDING THAT RATE DS REPRESENTS FIRM SERVICE?

A. The Company's Tariff, Sheets 38 and 39, indicates that Rate DS is, at least in part, firm service. Specifically, Items (3) and (4) under "Availability" states as follows:

> (3) Company will not be required to deliver on any day more than the lesser of (i) a quantity of gas equivalent to Customer's Maximum Daily Volume specified in its Delivery Service Agreement; (ii) the quantity of gas scheduled and confirmed to be delivered into the Company's distribution facilities on behalf of the Customer on that day plus applicable Standby Sales; or (iii) the Customer's Authorized Daily Volume, and,

(4) On an annual basis, a Customers Maximum Daily Volume and Annual Transportation Volume will be automatically adjusted to the Customers actual Maximum Daily Volume and actual Annual Transportation Volume based on the Customers highest daily and annual volumetric consumption experienced during the preceding 12-month periods ending with March billings. Upon a Customers request, the Company shall have the discretion to further adjust a Customers Maximum Daily Volume and Annual Transportation Volume for a good cause shown.

Q. FOR COST ALLOCATION PURPOSES, HAS MR. FEINGOLD ASSIGNED ANY MAINS COSTS TO DS AND IS SERVICE?

A. Only a very disproportionally small amount. With regard to Rate IS, Mr. Feingold allocated no mains costs to this rate schedule under his Customer/Demand approach. Under his Peak and Average study, Mr. Feingold assigned no "peak" portion to Rate IS but did include IS throughput within the "average" portion of the mains allocator. However, my concerns are not so much with Rate IS but rather Rate DS.[13] With regard to Rate DS, Mr. Feingold includes 5,200 MCF of design day demand associated with the smaller, grandfathered, DS customers,[14] but excluded 96,200 MCF of design day demand associated with larger DS customers.[15]

Q. IS THERE FURTHER EVIDENCE TO SUGGEST THAT RATE DS SHOULD BE SEPARATED FROM IS AND THAT THE DESIGN DAY ALLOCATOR SHOULD INCLUDE DEMANDS FROM LARGE DS CUSTOMERS?

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13 It is my opinion that regardless of allocation methodology, interruptible service should be allocated some mains costs - perhaps to a lesser degree than firm service, but some costs nonetheless.

14 These grandfathered customers are required to subscribe to stand-by service.

15 Per response to AG 1-266 and 1-272 ("data sheet").

A. Yes. In response to AG 1-266 and AG 1-272, the Company provided its "design day" demands by individual rate schedule. In these responses, Columbia included the 96,200 MCF associated with large DS customers but referred to this as "interruptible" and "non-firm" design day demands. In all of my years of practice, I have never encountered such a thing as "interruptible" or "non-firm" design day requirements or demands. This is because, by definition, design day demand represents the level of demand that a utility plans for, "designs," and installs capacity. Traditionally, utilities do not install capacity for interruptible loads as these are considered opportunistic demands such that these customers are only served during periods of idle capacity. Therefore, as shown in response to AG 1-266, the large DS customers are reflected in Columbia's design day demand but simply excluded for cost allocation purposes.

Q. DOES THIS EXCLUSION OF RATE DS DEMANDS HAVE A MATERIAL IMPACT ON MR. FEINGOLD'S CCOSS RESULTS?

A. Yes. According to Columbia's response to AG 1-266, the total Company design day demand is 325,500 MCF. The 96,200 MCF of large DS demand represents about 30% of this amount (29.55%). Therefore, by excluding demand cost responsibility for large DS customers means that all other customers are assigned a much higher portion of Columbia mains and mains-related costs.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS REGARDING THE SEPARATION OF IS AND DS CUSTOMERS FOR COST ALLOCATION PURPOSES?

A. Unless my understanding of Columbia's written Tariff and responses to data requests is incorrect such that Rate DS is in fact clearly and <u>totally</u> interruptible, and that Columbia has not designed and installed capacity to meet the large customer requirements, the IS and DS rate schedules should be separated for costing purposes. Furthermore, the firm obligation of Columbia to its DS customers should be reflected within the allocation of mains.

Q. NOTWITHSTANDING THE DEFINITION OF CLASSES, DO YOU HAVE OTHER DISAGREEMENTS OR CONCERNS WITH MR. FEINGOLD'S CCOSS STUDIES?

A. Yes. Perhaps the easiest way to explain my other disagreements is to group them into four categories in order to enable the Commission and parties to understand the quantifiable impact of these disagreements (in terms of class rates of return). These four groups of differences can be categorized as: (1) conceptual disagreements and/or programming errors in Mr. Feingold's selection and use of specific allocators; (2) the treatment and allocation of NiSource Service Company ("NCSC") costs assigned to Columbia of Kentucky; (3) the inclusion of discounted rate (non-Mainline) customer demands within the cost allocation process; and, (4) the treatment of large Rate DS demands within the cost allocation process.

Q. PLEASE IDENTIFY AND EXPLAIN YOUR CONCEPTUAL DISAGREEMENTS AND/OR PROGRAMMING ERRORS YOU DISCOVERED IN MR. FEINGOLD'S CCOSS STUDIES.

A. I will explain my differences and corrections to Mr. Feingold's CCOSS by first discussing the allocation of mains cost to the IUS (wholesale) class, then rate base items, and finally expenses.

Unlike all prior CCOSS conducted by Columbia, Mr. Feingold has not assigned any mains cost to its wholesale (IUS) customers. In response to AG 1-266, the Company clearly indicates that the design day demand for this class is 200 MCF/day. Unless these wholesale customers take service directly from an interstate pipeline (and therefore do not rely upon Columbia's distribution facilities), the class should be allocated a fair share of distribution costs including mains. As has been done by Columbia in all other cases, I have assigned mains and other distribution costs to the IUS class.

Q. PLEASE EXPLAIN YOUR DISAGREEMENTS WITH MR. FEINGOLD'S ALLOCATION OF VARIOUS RATE BASE ITEMS.

A. The first rate base item concerns Mr. Feingold's allocation of Account 303, Miscellaneous Intangible plant ($4,186,371). Mr. Feingold classified this account as 100% "customer" and thus, allocated this account on customers. However, Miscellaneous Intangible plant reflects investment in miscellaneous items (largely software) that supports all of Columbia's operations. In response to AG 2-29 (attached as my Schedule GAW-2), Columbia provided a detailed itemization of this account. As can be seen from this response, the items comprising this account generally support all of the Company's operations. Furthermore, in Columbia's last rate case, the Company allocated this account on the more accepted approach based on total distribution plant. I have also allocated Account 303 on distribution plant.[16] To illustrate the impact of this difference, Mr. Feingold allocated 83.2% of this account to the residential class (under his Peak and Average study) whereas my allocator results in a 61.8% allocation to the residential class.

The next difference concerns Distribution Plant Accounts 374 and 375 (Land & Rights of Way, Structures & Improvements). Mr. Feingold allocated these amounts based on total distribution plant which includes Meters, Services, and House Regulators. Meters, Services, and Regulators have no correlation to, and are not cost causative of distribution Land, or Structures and Improvements. Rather, Accounts 374 and 375 primarily are needed for, and support, distribution mains. As such, I have allocated these investments in the same manner as mains investment. It should be noted that my allocation is also consistent with Columbia's CCOSS in the last case. Mr. Feingold allocated 83.2% of these costs to the residential class whereas as my approach, and that used by Columbia in the last case, assigns 46.6% to the residential class.

The next difference relates to Accounts 378 and 379 (Distribution and City Gate Measuring & Regulating Station Equipment). Mr. Feingold allocates these amounts strictly on design day demand, whereas in the last case, Company employee witness Mark Balmert allocated these accounts on the same basis as mains. I concur with the Company's prior approach since these costs are incurred in the same manner as mains and support mains investment. Mr. Feingold's Peak and Average study allocates 62.0% of these costs to the residential class, whereas Columbia's prior method as well as my approach assigns 46.6% to residential customers.

[16] To avoid any controversy, I also included the minimal amount of land that is booked to Account 304, Production Land.

Q. PLEASE EXPLAIN YOUR DISAGREEMENTS RELATING TO THE ALLOCATION OF EXPENSES.

A. With regard to expenses, many of the differences between Mr. Feingold and I (as well as Columbia's CCOSS in the last case) are the same as those for plant. For example, whereas Mr. Feingold allocated Account 875, Measuring and Regulating Station Expenses based on design day demand, I allocated this account based on mains investment in the same manner as Columbia did in its last rate case.

With regard to Account 379, Customer Installations Expense, Mr. Feingold allocated this expense based on Service Line Investment (Account 380). I have allocated this expense in the same manner as Columbia did in its last CCOSS, which is on the basis of Meters Investment.

The next set of differences in expenses is the result of what I believe is an inadvertent programming error made by Mr. Feingold. This relates to expense Accounts 880, 881, 885, 886 and 894 (Other Distribution Expense, Distribution Rents, Distribution Maintenance Supervision & Engineering, Distribution Maintenance of Structures & Improvements, and Maintenance of Other Distribution Equipment). Mr. Feingold first classified these expenses as partially "demand," "customer," and "commodity." With regard to the "demand" and "customer" classified portions of these expenses, he then allocated these amounts on all Other Distribution O&M accounts, which is perfectly acceptable. However, with regard to his "commodity" portion of these expenses he allocated these amounts based on total O&M expenses including Customer Accounting, Customer Service, and Administrative expenses. I have corrected this apparent error and allocated all of these referenced expenses based on all Other Distribution expenses which is consistent with Columbia's approach in the last case.

The next expense differences relates to Accounts 912 and 913 (Demonstrating and Selling and Advertising Expenses). Whereas Mr. Feingold allocated these accounts based on annual throughput (MCF usage), I have followed the procedure used by Columbia in the last case and allocated these accounts based on number of customers.

The last group of expense allocation differences relate to Accounts 928, 930, and 931 (Regulatory Commission Expenses, Miscellaneous General Expenses and Rents Expense). Mr. Feingold allocated these expenses based on total Administrative & General Expenses, whereas I utilized the more accepted approach (and also used by Columbia in the last case) of allocating these expenses based on total O&M Expense excluding gas costs, Uncollectibles, and Other A&G Expenses.

Q. HOW DOES YOUR SELECTION OF THE ABOVE ALLOCATIONS, WHICH IS CONSISTENT WITH COLUMBIA'S APPROACH IN THE PRIOR CASES, AFFECT CLASS RATES OF RETURN ("ROR") AT CURRENT RATES?

A. In order to evaluate the magnitude of the allocation factor differences, the following Table 2 shows class rates of return at current rates using the Peak & Average approach and compares Mr. Feingold's results with those obtained using my adjustments to the allocation of rate base, expenses, and assigning peak demand to Rate IUS:

TABLE 2

	Current Rates			
	ROR		Indexed ROR	
	Feingold P&A	AG Allocators P&A	Feingold P&A	AG Allocators P&A
GS-Residential	1.26%	2.35%	35%	65%
GS-Other	8.46%	6.83%	232%	188%
IUS	-10.10%	-9.77%	-277%	-271%
ML/SC	363.36%	883.33%	NM*	NM*
DS/IS	4.11%	1.49%	113%	41%
TOTAL COMPANY	3.64%	3.64%	100%	100%

* Means Not Meaningful.

Q. PLEASE EXPLAIN MR. FEINGOLD'S TREATMENT AND ALLOCATION OF NISOURCE CORPORATION SERVICE COMPANY ("NCSC") COSTS ASSIGNED TO COLUMBIA GAS OF KENTUCKY.

A. NCSC provides management and professional services to its various LDC affiliates. In addition, NCSC allocates various parent company (NiSource Corporate) overhead costs, such as executive salaries, corporate auditing and legal to its affiliates. For the future test year, $12,733,636 in NCSC charges are assigned to Columbia Gas of Kentucky and are reflected in the Company's overall revenue requirement in this case. To put the magnitude of the NCSC charges in context, this $12.734 million in NCSC charges represents about 40% (39.4%) of Columbia's total requested Operating and Maintenance ("O&M") expenses excluding gas costs and uncollectibles. The Company's response to AG 1-284 (attached as Schedule GAW-3) provides a detailed itemization of this $12.7 million charge by NiSource department and function. As can be seen in Schedule GAW-3, this itemization of NCSC charge is not broken down or separated by

FERC account but rather by service function. In data request AG 1-285, it was requested that Columbia provide these NCSC charges by FERC account. In its response, the Company indicated that the requested information is not available for the forecasted test period, but it did provide an estimate of the $12.7 million by FERC account based on "a historic trend," for the twelve months ending December 31, 2012. This statement is somewhat confusing in that Mr. Feingold's CCOSS separates all Columbia Gas of Kentucky costs by FERC account and that the total O&M expenses in his CCOSS exactly matches the Company's forecasted test year expenses (which includes NCSC charges). Since Mr. Feingold's CCOSS reflects every expense (including the NCSC charges) by FERC account, he (or someone else) must have either: (a) allocated this $12.7 million to specific accounts; or, (b) adjusted each FERC account forecast to ensure that the sum of all FERC expense accounts exactly matched the Company's proposed revenue requirement total expenses. It is clear from Columbia's response to AG 1-285 and from Mr. Feingold's CCOSS that the majority of this $12.7 million of NCSC charges is assigned to Account No. 923 (Outside Services). However, the remaining (about $3.5 million) is somehow assigned to other account numbers. With these observations noted, I then accepted the Company's estimated itemization of the $12.7 million in NCSC charges by FERC account provided in AG 1-285 and allocated these amounts to classes using the exact same allocation factors, and amounts Mr. Feingold used in his two CCOSS (Customer/Demand and Peak & Average). These calculations and allocation of NCSC charges to classes are shown in my Schedule GAW-4, page 1 (Customer/Demand) and page 2 (Peak & Average) and are summarized below:

TABLE 3
Feingold Allocations of $12.734 million NCSC Charges

Study	Class				
	GS-Res	GS-Other	IUS	ML/SC	DS/IS
Customer/Demand	78.1%	18.8%	0.1%	0.3%	2.7%
Peak & Average	72.3%	20.1%	0.1%	0.3%	7.2%

Remembering that the $12.7 million of NCSC charges reflect fees for Management & Professional Services as well as allocated NiSource Corporate overhead costs such as executive salaries, corporate auditing, and legal costs, it is therefore, logical, equitable, and appropriate to assign these costs to classes based on the utilization of Columbia's facilities; i.e., MCF usage. As shown earlier in my testimony, the following are the class percentages of annual MCF utilization of Columbia's resources:

TABLE 4

	Class				
	Resid.	GS-Other	IUS	ML/SC	DS/IS
Annual MCF	26.363%	17.819%	0.046%	15.615%	40.157%

As can be seen above, there is a tremendous disparity between Mr. Feingold's assignment of NCSC charges and that which is more logical, equitable, and in my opinion, appropriate.

Q. HAVE YOU CALCULATED THE CLASS ROR IMPACTS BY ASSIGNING NCSC CHARGES BASED ON ANNUAL MCF USAGE INSTEAD OF MR. FEINGOLD'S ASSIGNMENT OF THESE COSTS?

A. Yes. Building upon the different allocation factor results presented earlier, the following are the class ROR's that are produced when NCSC charges are allocated to classes based on annual MCF usage:

TABLE 5

ROR's @ Current Rates Utilizing AG Allocation Factors
And Allocation of NCSC Charges Based On Annual MCF

	Class					
Study	GS-Res	GS-Other	IUS	ML/SC	DS/IS	Total Company
Customer/Demand	2.58%	10.91%	-8.00%	-2,343.12%	-18.14%	3.64%
Peak & Average	6.39%	7.85%	-8.38%	-2,479.39%	-11.35%	3.64%

As can be seen above, this reassignment of NCSC charges has a dramatic impact on class ROR's such that under the Peak & Average approach, the residential class is contributing more to Columbia's profits (6.39%) than the system-wide average (3.64%). Furthermore, when the Customer/Demand approach is considered, the residential class increases from Mr. Feingold's -1.52% ROR to +2.58% ROR.

Q. EARLIER YOU EXPLAINED THAT MR. FEINGOLD DID NOT INCLUDE SPECIAL CONTRACT CUSTOMERS' PEAK DEMANDS (DESIGN DAY) IN HIS CCOSS. HAVE YOU CALCULATED THE ROR IMPACTS WITH THE INCLUSION OF THESE DISCOUNTED RATE CUSTOMERS' DESIGN DAY DEMANDS?

A. Yes. However, as discussed earlier it should be noted that my analysis reflects Mr. Feingold's incorrect categorization of certain Special Contract customers within the DS/IS class. Building upon the CCOSS results I have already discussed, the following class ROR's (at current rates) are achieved when non-Mainline Special Contract customers are allocated a portion of mains:[17]

TABLE 6

ROR's @ Current Rates Utilizing AG Allocation Factors
Allocation of NCSC Charges and Allocation of Mains to Special Contracts

	Class					
Study	GS-Res	GS-Other	IUS	ML/SC	DS/IS	Total Company
Customer/Demand	2.74%	11.43%	-8.00%	-430.87%	-12.40%	3.64%
Peak & Average	6.81%	8.44%	-8.34%	-106.46%	-11.30%	3.64%

Q. WHY IS THERE SUCH A DRAMATIC CHANGE IN THE ROR's FOR THE ML/SC CLASS BETWEEN THOSE SHOWN IN TABLE 5 AND THOSE SHOWN IN TABLE 6?

A. This is because under Mr. Feingold's approach (as reflected in Table 5) the ML/SC class is allocated almost no rate base. However, when Special Contract customer FX7 is included within the allocation of mains, the allocated rate base for this class increases considerably. As such, because the denominator in the ROR calculation is rate base, the change greatly affects the class ROR.

Q. HAVE YOU ALSO CALCULATED THE ROR IMPACTS WITH THE INCLUSION OF LARGE TRANSPORTATION, RATE DS CUSTOMERS INCLUDED WITHIN THE ALLOCATION OF MAINS?

[17] Peak demands for Special Contracts were estimated based on forecasted test year average daily January usage per AG 1-271.

A. Yes. The Table below reflects the inclusion of the design day demands for large DS customers within the allocation of mains.[18] The details supporting my cost allocation adjustments using the Peak & Average method are provided in my Schedule GAW-5.

TABLE 7

ROR's @ Current Rates Utilizing All Previous Adjustments
And Inclusion of DS For The Allocation of Mains

	Class					
Study	GS-Res	GS-Other	IUS	ML/SC	DS/IS	Total Company
Customer/Demand	3.50%	13.91%	-7.78%	-559.36%	-11.68%	3.64%
Peak & Average	8.27%	10.53%	-8.22%	-112.77%	-11.15%	3.64%

Q. EVEN THOUGH MAINS SHOULD NOT BE ALLOCATED PARTIALLY ON THE BASIS OF NUMBER CUSTOMERS, HAVE YOU EXAMINED MR. FEINGOLD'S CLASSIFICATION STUDY THAT SEPARATES MAINS BETWEEN CUSTOMER AND DEMAND COMPONENTS?

A. Yes.

Q. DO YOU AGREE WITH THE CUSTOMER/DEMAND SPLIT MR. FEINGOLD USED IN HIS CUSTOMER/DEMAND CCOSS?

A. No. Before I explain the numerical bias that results from Mr. Feingold's mains classification analysis, it should be remembered what is the analyst is trying to accomplish conceptually once a decision is made to classify mains as partially customer-related and partially demand-related. Under the minimum-system (size) approach, one estimates the customer component of mains based on the smallest (and cheapest) size pipe installed which then serves as a proxy for the customer portion of mains. Because

[18] The DS design day demands are per response to AG 1-266.

even the smallest size of pipe has a considerable amount of load carrying capacity, and in fact, is used to meet these customers' design day demands that are connected to this minimum-size pipe, the zero-intercept method attempts to correct for the overstatement of the customer component inherent with the minimum-size approach. Under a properly applied zero-intercept method, the analyst estimates the cost per foot of a theoretically zero-sized pipe. In this way, such a "zero-size" pipe would have no load carrying capacity but would only include costs to install this non-load carrying main (primarily capitalized labor costs). With this foundation established, we can now turn to Mr. Feingold's Customer/Demand classification analyses used for mains.

Mr. Feingold used statistical linear regression to estimate his zero-intercept approach for his mains classification. As is a generally accepted practice, Mr. Feingold separated mains between steel and plastic pipe and conducted separate analysis for each group. In response to AG 1-266, Mr. Feingold's zero-intercept data sets and analyses were provided. The following list shows the actual (data set) costs per foot that he used in developing his zero-intercept (percent customer).

TABLE 8
Feingold Data Used For Mains Classification
(Cost Per Foot)

Size	Steel	Plastic
0.75	$15.58	--
1.00	$23.77	$7.97
1.25	$18.53	$9.36
1.50	$39.88	--
2.00	$21.81	$12.20
2.50	$27.37	--
3.00	$31.72	$21.63
4.00	$41.04	$29.11
4.50	$51.19	--
5.19	$51.63	--
6.00	$58.08	$50.76
6.25	$35.92	--
6.63	$55.85	--
8.00	$84.79	$58.32
8.25	$56.26	--
10.00	$120.60	$83.03
12.00	$140.90	--
14.00	$183.82	--
16.00	$187.54	--

With the above unit costs noted (cost per foot) we can now evaluate the cost Mr. Feingold estimated as a "zero-size" pipe per his statistical analysis. For steel pipe, Mr. Feingold determined a zero-intercept of $32.81 and for plastic pipe a cost of $15.59. These results are clearly non-sensical since his own data set reflects actual costs for pipe as low as $7.97 (1.00 inch plastic pipe). Therefore, it can be readily observed that Mr. Feingold's own analysis is seriously flawed in that at the very least, he has overstated the customer component of steel and plastic by about double the amount it should be.[19] As a result, even if one were to consider a customer component of mains, Mr. Feingold's

[19] The minimum actual cost of steel pipe is $15.58 for about half that of Mr. Feingold's zero-size estimate of $32.81. The minimum actual cost of plastic pipe is $7.97 for about half that of Mr. Feingold's zero-size estimate of $15.59.

customer percentage of 56.94% is overstated by about double the amount it should be; i.e., about 28% versus 57%).

Q. DOES MR. FEINGOLD'S FLAWED ZERO-INTERCEPT ANALYSIS BIAS ANY PARTICULAR CLASSES IN HIS CUSTOMER/DEMAND CCOSS?

A. Yes. Mr. Feingold's flawed Customer/Demand split of mains severely over-allocates cost to the residential class since this class represents about 90% of the number of customers but only about 41% of the proper design day demand.[20] As such, Mr. Feingold's classification of mains significantly over-assigns mains and mains-related costs to the residential class.

Q. HAVE YOU CALCULATED CLASS RORs USING A MORE REASONABLE CUSTOMER/DEMAND SPLIT FOR MAINS?

A. No. As I discussed earlier, it is not appropriate for mains to be allocated with <u>any</u> consideration of customer counts. However, if one were to consider a classification of mains between customer and demand, the residential rate of return of 3.50% presented in Table 7 would be considerably higher.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS REGARDING CLASS COST ALLOCATIONS FOR PURPOSES OF THIS CASE?

A. Considering the improper definition of classes, errors in the placement of certain Special Contract customers to the appropriate class, inconsistencies with Columbia's

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[20] The demand percentage of 41% reflects the inclusion of Special Contracts and large DS customers. If these customers are excluded the residential demand percentage is 61%.

prior CCOSSs, failure to recognize the demand requirements of Special Contracts and Large Delivery Transportation customers, biased and improper assignment (allocation) of NCSC costs, and even the biases contained in Mr. Feingold's Customer/Demand analysis, no recognition should be given to any cost allocations in this case for purposes of evaluating class revenue responsibility or in assigning the overall approved increase in revenue requirement to individual classes.

III. SPECIAL CONTRACT (DISCOUNTED RATES)

Q. PLEASE EXPLAIN THE CONCEPT OF DISCOUNTED AND "FLEX" RATES AS THEY RELATE TO COLUMBIA GAS OF KENTUCKY.

A. As is the case with many LDCs, Columbia sometimes offers discounted rates (below Commission approved rates) to large customers that have a legitimate threat of by-passing the Company's distribution system and purchasing directly from an interstate pipeline, or that have alternative energy sources that are lower in cost than natural gas. With regard to customers that have alternative energy sources, Columbia may "flex" the rate charged for its distribution service to compete with these alternative energy sources. Under the provisions of the Company's Tariff, once a customer contracts with Columbia for "flex" service, the actual distribution rate charged may be less than or as much as 150% more than the Commission approved base rate tariff; i.e., if the alternative energy source becomes more expensive than natural gas, Columbia may "flex" its base rate above the full tariff to reflect the higher cost of a competing energy source.

Q. DO ANY OF COLUMBIA'S CUSTOMERS HAVE "FLEX" SERVICE ASSOCIATED WITH ALTERNATIVE ENERGY SUPPLIES?

A. No. According to the Company's Confidential response to AG 1-282, no customers receive a flex rate due to alternative energy sources.

Q. DOES COLUMBIA OFFER ANY DISCOUNTED RATES DUE TO THE THREAT OF INTERSTATE PIPELINE BY-PASS?

A. Yes. Columbia has five customers (with a total of seven accounts) that receive discounted rates due to an alleged threat of interstate pipeline by-pass. Of these five customers (seven accounts), two customers (three accounts) are considered "Mainline" customers wherein the other three customers (four accounts) require the use of the Company's distribution facilities.

Q. HAVE YOU INVESTIGATED THE LEGITIMACY OF THESE NON-MAINLINE DISCOUNTED RATE CUSTOMERS' POTENTIAL THREATS FOR BY-PASS AND THE REASONABLENESS OF THE DISCOUNTED RATES CHARGED TO THESE "SPECIAL CONTRACT" CUSTOMERS?

A. Yes. In Confidential data request AG 1-282, the Company was asked among other things to provide: the actual rates being charged to each customer; a copy of all service agreements associated with these customers; and, all records, documents, evaluations, and analyses undertaken to demonstrate that a lower than full tariff rate is necessary to retain these customers. Since two of the Special Contract customers (three accounts) are located directly adjacent to an interstate pipeline, no further justification was necessary.

However, it should be noted that **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

With regard to the three discounted rate customers (four accounts) that rely on Columbia's distribution facilities, the following are the effective base rates charged to each customer compared to the Commission approved full tariff DS rate:[21]

TABLE 9

Customer	Effective Discounted Rate	Rate DS Full Tariff Rate[22]	Annual Discount ($)
	BEGIN CONFIDENTIAL		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	END CONFIDENTIAL		
TOTAL	--	--	$694,956

Q. PLEASE DISCUSS AND EXPLAIN THE COMPANY'S SUPPORT FOR OFFERING A RATE DISCOUNT TO CUSTOMER A.

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[21] The negotiated rates for Customers A and C reflect declining-block delivery usage charges. The effective delivery rate was calculated based on these declining-block rates applied to each Customers' monthly usage provided in response to AG 1-271, Attachment A.

[22] The effective full tariff rate reflects the declining-block rate structure and is applied to each customer's monthly usage for the forecasted test year.

A. In its Confidential response to AG 1-282, the Company provided cost analyses for this customer under "low risk," "medium risk," and "high risk" threats of by-pass. These three scenarios assumed different levels of annual volumes. Because the "medium risk" scenario assumes an estimated annual volume for this customer of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** MCF, which is very close to the forecasted test year usage for this customer of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** MCF, I will focus on this cost analysis. According to Columbia's response, Customer A is located **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** from the closest interstate pipeline. Considering that Customer A is a private enterprise, and, therefore, does not have any possibility for eminent domain, it is surely a practical impossibility for this customer to secure the needed land and/or rights of way to traverse other property owners' real estate and build its own by-pass pipe to connect to the interstate pipeline. Notwithstanding the virtual impossibility of this customer being able to secure the required land and land rights necessary to connect to an interstate pipeline, the Company's cost analysis provides no cost provision, or allowance for, the acquisition of land or land rights. Finally, the Company's cost analysis indicates that Customer A would require an **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL.** Such an estimate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** per foot is grossly understated considering that during 2012, it cost Columbia an average of $124.50 per foot to install 8-inch steel pipe and $174.47 per foot to install 8-inch plastic pipe.[23] A copy of the Company's threat of by-pass cost analysis for Customer A is provided in my Confidential Schedule GAW-6.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE VIABILITY OF CUSTOMER A ACTUALLY BEING ABLE TO BY-PASS COLUMBIA'S DISTRIBUTION SYSTEM?

A. It is quite clear that this customer has no realistic threat of by-passing Columbia's distribution system and purchasing directly from an interstate pipeline.

Q. NOTWITHSTANDING YOUR OPINION THAT CUSTOMER A HAS NO LEGITIMATE THREAT OF BY-PASSING COLUMBIA'S SYSTEM, WHAT IS COLUMBIA'S CALCULATED "THREAT OF BY-PASS RATE" FOR THIS CUSTOMER COMPARED TO THE RATE IT IS ACTUALLY CHARGING THIS CUSTOMER?

A. This customer is served under a **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** contract and Columbia's calculated threat of by-pass rate for this customer is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL.** This compares to the actual effective rate charged this customer of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** as shown in Table 9 above.

Q. PLEASE DISCUSS AND EXPLAIN THE COMPANY'S SUPPORT FOR OFFERING A RATE DISCOUNT TO CUSTOMER C.

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23 Calculated per Columbia's property accounting records in response to AG 1-266.

A. The Company also provided the same information as discussed above for Customer C. According to Columbia, Customer C is located **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** from the nearest instate pipeline. Although this customers' distance to an interstate pipeline is considerably shorter than Customer A's, it would still require this customer to traverse more than **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of land to connect to an interstate pipeline. I do not know how many property owners would be involved, but it is reasonable to infer that it would be several. Most importantly is the fact that this customer has no eminent domain authority and it is very unlikely that each and every land owner would agree to have a natural gas pipeline running through their property. Furthermore, it is also not known how many roads and highways would have to be crossed in order for Customer C to build a by-pass pipeline. In their cost analysis, Columbia does appear to have made an allowance of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** to secure land and rights-of-way associated with this potential by-pass. Because the Company's "high risk" scenario produces the lowest calculated by-pass rate, I will refer to this cost analysis for purposes of this discussion. For Customer C, Columbia also utilized a required **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** pipe for this customer and assumed that this customer could purchase and install an **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** per foot as compared to the actual cost to Columbia of $124.00 to $174.00 per foot. Obviously, had Columbia utilized a more realistic cost per foot for this customer's by-pass piping, a much higher rate than that calculated by Columbia would result. A copy of the Company's threat of by-pass cost analysis for Customer C is provided in my Confidential Schedule GAW-7.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE VIABILITY OF CUSTOMER C ACTUALLY BEING ABLE TO BY-PASS COLUMBIA'S DISTRIBUTION SYSTEM?

A. It is most likely that this customer has no realistic threat of by-passing Columbia's distribution system and purchasing directly from an interstate pipeline.

Q. NOTWITHSTANDING YOUR OPINION THAT CUSTOMER C HAS NO LEGITIMATE THREAT OF BY-PASSING COLUMBIA'S SYSTEM, WHAT IS COLUMBIA'S CALCULATED "THREAT OF BY-PASS RATE" FOR THIS CUSTOMER COMPARED TO THE RATE IT IS ACTUALLY CHARGING THIS CUSTOMER?

A. This customer is also served under a **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** contract and Columbia's calculated threat of by-pass rate for this customer is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL.** This compares to the actual effective rate charged this customer of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** as shown in the previous table. Furthermore, Columbia's calculated by-pass rate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** is grossly understated at the very least due to an unreasonably low estimated construction cost of pipe; i.e., **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** versus $124.00 to $174.00/foot.

Q. PLEASE DISCUSS AND EXPLAIN THE COMPANY'S SUPPORT FOR OFFERING A RATE DISCOUNT TO CUSTOMER E.

A. The Company also provided the same information as discussed above for Customer E. According to Columbia, Customer E is located **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** from the nearest interstate pipeline. Although this customers' distance to an interstate pipeline is about half that of Customer A, it would still require this customer to traverse more than **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of land to connect to an interstate pipeline. I also do not know how many property owners would be involved, but it is reasonable to infer that it would be several. Again, most importantly, is the fact that this customer has no eminent domain authority and it is very unlikely that each and every land owner would agree to have a natural gas pipeline running through their property. Furthermore, it is also not known how many roads and highways would have to be crossed in order for Customer E to build a by-pass pipeline. The Company's threat of by-pass analysis for Customer E reflects annual usages of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. Considering that the Company's forecasted test year for Customer E (two accounts combined), is only **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**, my discussion will focus on the "low risk" **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** cost scenario conducted by Columbia. For Customer E, Columbia also utilized a required **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** pipe for this customer and assumed that this customer could purchase and install **BEGIN CONFIDENTIAL** [redacted]

[redacted] **END CONFIDENTIAL** as compared to the actual cost to Columbia of $124.00 to $174.00 per foot. Obviously, had Columbia utilized a more realistic cost per foot for this customer's by-pass piping, a much higher rate than that calculated by Columbia would result. A copy of the Company's threat of by-pass cost analysis for Customer E is provided in my Confidential Schedule GAW-8.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE VIABILITY OF CUSTOMER E ACTUALLY BEING ABLE TO BY-PASS COLUMBIA'S DISTRIBUTION SYSTEM?

A. It is clear that this customer has no realistic threat of by-passing Columbia's distribution system and purchasing directly from an interstate pipeline.

Q. NOTWITHSTANDING YOUR OPINION THAT CUSTOMER E HAS NO LEGITIMATE THREAT OF BY-PASSING COLUMBIA'S SYSTEM, WHAT IS COLUMBIA'S CALCULATED "THREAT OF BY-PASS RATE" FOR THIS CUSTOMER COMPARED TO THE RATE IT IS ACTUALLY CHARGING THIS CUSTOMER?

A. This customer also has a **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** agreement with Columbia. Columbia's calculated threat of by-pass rate for this customer is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. This compares to the actual effective rate charged to this customer of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. However, it should be noted that the actual effective rate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** is calculated from the Company's revenue proof in this case for purposes of establishing its requested revenue requirement. At the same time, the service agreement calls for a minimum rate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. As such, it appears that the Company's rate application understates the actual revenues associated with this customer by about $159,700 **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. Regardless of whether the actual rate charged to Customer E is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**, the delivery rate charged to this customer is grossly below Columbia's own by-pass rate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. Finally, it must be remembered that the Company's calculated by-pass rate of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** is significantly understated due to an unrealistically low assumed cost of pipe.

Q. **HOW DOES COLUMBIA PROPOSE TO FUND THE AGGREGATE $694,956 DISCOUNT PROVIDED TO THESE SPECIAL CONTRACT CUSTOMERS?**

A. Columbia proposes that its captive ratepayers entirely fund this discount.

Q. **IS COLUMBIA'S PROPOSED RATEMAKING TREATMENT OF THESE DISCOUNTS FAIR AND REASONABLE?**

A. In these circumstances, no. If there were indeed, a legitimate and viable threat of by-pass, it would be reasonable for ratepayers to fund such discounts. However, this is not the case for the three customers in question. It is quite clear that these customers have no realistic potential to acquire land or land rights needed to build a pipe and traverse the distances required to connect to an interstate pipeline. Furthermore, the threat of by-pass cost analyses conducted by Columbia for each customer is unrealistically low, and in fact, reflect significantly lower materials and construction costs for similar size pipes than it costs Columbia, which is in the business of building and installing natural gas mains. Finally, even if one were to accept the notion that these customers could by-pass Columbia's distribution system, and one were to accept Columbia's unrealistically low "stand-alone" construction costs for these customers to design and install their own pipe, the discounted rate actually being charged to these customers are significantly below those of Columbia's own cost estimate thresholds.

Q. WHAT IS YOUR RECOMMENDATION AS TO THE RATEMAKING TREATMENT OF THIS $694,956 IN DISCOUNTS OFFERED TO THESE THREE CUSTOMERS?

A. Captive ratepayers should not fund the unreasonably low rates afforded to these special customers. As such, and as will be discussed later in the Class Revenue Allocation Section of my testimony, the first $694,956 of any required overall increase in revenue requirement should be taken off the top and ascribed to these Customers. Whether these three special customers actually pay this difference of $694,956, is frankly, immaterial. In other words, if Columbia is unable to collect these unreasonable discounts, it should come from shareholders and not captive ratepayers.

IV. CLASS REVENUE ALLOCATION

Q. HAVE YOU DEVELOPED A PROPOSED CLASS REVENUE INCREASE DISTRIBUTION FOR THIS CASE?

A. Yes. As indicated earlier, the first step in assigning any overall revenue increase authorized in this case is to eliminate (assign) the discount associated with the three non-Mainline Special Contract customers that totals $694,956 to the applicable Special Contract rates. Considering the lack of usefulness of cost allocation results in this case, or even the wide range of results obtained under alternative approaches, I recommend that the remaining overall increase authorized in this case be spread on an equal percentage basis to all classes based on current base rate revenues. Under my recommended approach, the following is a comparison of my recommended class increases to those proposed by Columbia:

TABLE 10
Comparison of Columbia & AG Proposed Class Revenue Increases
At Columbia Proposed Overall Increase
($ Thousands)

Class	Current Delivery Revenue[24]	Columbia Proposed Increase ($)	Columbia Proposed Increase (%)	AG Proposed Increase Initial	AG Proposed Increase Remaining	AG Proposed Increase Total	Percent
GS-Res	$34,273	$11,809	34.46%		$9,909	$9,909	28.91%
GS-Other	$14,592	$4,441	30.44%		$4,219	$4,219	28.91%
IUS	$20	$6	32.78%		$6	$6	28.91%
ML/SC	$641	$0	0.00%	$177	$185	$362	56.56%
DS/IS	$5,255	$276	5.26%	$518	$1,519	$2,037	38.77%
TOTAL COMPANY	$54,780	$16,533	30.18%	$695	$15,838	$16,533	30.18%

The details of my proposed revenue increase distribution by specific rate schedule is provided in my Schedule GAW-9.

24 Includes AMRP revenue.

Q. TO THE EXTENT THE COMMISSION AUTHORIZES AN OVERALL INCREASE LESS THAN THE $16.533 MILLION REQUESTED BY COLUMBIA, HOW SHOULD THE ULTIMATE OVERALL INCREASE BE ASSIGNED TO INDIVIDUAL RATE SCHEDULES AND CLASSES?

A. The approach discussed above should simply be scaled-back. In other words, the first $694,956 of unjustified special rate discounts should be assigned to those Special Contract rate customers. The remaining increase should be assigned to all rate schedules and classes on an equal percentage basis.

V. <u>RATE DESIGN AND REVENUE NORMALIZATION ADJUSTMENT ("RNA") MECHANISM</u>

Q. PLEASE DESCRIBE COLUMBIA'S CURRENT RESIDENTIAL RATE STRUCTURE.

A. Columbia's current residential rate structure includes a fixed monthly customer charge of $12.35 plus a flat "base rate" distribution usage charge of $1.8715 per MCF for all gas consumed. In addition, residential customers pay a fixed monthly charge of $1.06 per customer for the Accelerated Mains Replacement Program Rider ("AMRP"). This AMRP Rider will be reset to $0.00 at the conclusion of this case and will automatically increase as Columbia replaces mains. Furthermore, residential customers are subject to a DSM Rider (currently at -$0.24 per customer per month) that varies from year to year. Finally, residential customers are subject to a Weather Normalization Adjustment

("WNA") Rider wherein a customer's actual usage is adjusted upward or downward to reflect abnormalities in the prior period temperatures.

Q. WHAT RATE STRUCTURE DOES COLUMBIA PROPOSE FOR THE RESIDENTIAL CUSTOMER CLASS IN THIS CASE?

A. Columbia is proposing to maintain its current basic residential rate structure that includes a fixed monthly customer charge, a flat usage charge per MCF, continuance of its AMRP and DSM Riders, as well the continuance of its WNA. However, in addition to the additional revenue stabilizing adjustment mechanisms already in place, Columbia proposes to add a new RNA Rider. Under the Company's proposal, residential revenue will be absolutely guaranteed regardless of weather variations, energy conservation, or any other factors or decisions that residential consumers make which might affect their natural gas usage.

Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN COLUMBIA'S RESIDENTIAL RATE DESIGN PROPOSAL?

A. Yes. It is clear that the primary objective of Columbia's residential rate design is to negate virtually all risks associated with serving its residential customers by guaranteeing its revenues from these customers.

Q. WHY DOES COLUMBIA'S PROPOSED RESIDENTIAL GUARANTEED RECOVERY RATE DESIGN REDUCE ITS RISKS?

A. If any business, governmental, or non-profit enterprises' revenues are guaranteed, that entity's net income and cash flows are more certain. Since risk is nothing more than a measure of certainty, guaranteed revenue collection substantially reduces risk by increasing income and cash flow certainty.

Q. BEFORE YOU CONTINUE, ARE THERE OTHER REGULATORY MECHANISMS IN PLACE THAT ALSO INCREASE COLUMBIA'S NET INCOME CERTAINTY, THEREBY REDUCING THE COMPANY'S RISK?

A. Yes. Any business' net income is simply a function of two factors: revenues and expenses. Columbia's proposed residential rate design addresses its desire to ensure 100% stable revenue recovery. However, Columbia already has an automatic gas cost recovery rider, an AMRP Rider, a DSM Rider, and a WNA mechanism in place which all substantially reduce any volatility in residential revenue due to virtually any reason.

As a result of all these current rider protections already in place, only three factors may affect residential net income: (1) Force Majeure; (2) year to year revenue variation (other than weather or energy conservation); and, (3) expense variations which are within management's control.

Q. IS THERE A RELATIONSHIP BETWEEN RISK AND REQUIRED RATE OF RETURN?

A. Absolutely. As is well known in financial and regulatory arenas, a firm's required rate of return is directly-related to the risk it confronts.

Q. HOW WOULD THIS RISK RELATE TO COLUMBIA'S PROPOSED RESIDENTIAL RATE DESIGN IF THE PROPOSED RNA WERE APPROVED?

A. The risk for residential customers is already virtually eliminated with all of the current riders in place that ensure revenue stability and recovery. As such, the Company's proposed RNA will do nothing more than provide an "umbrella policy" rider to ensure that the Company collects exactly the level of revenue approved in this case for establishing just and reasonable rates for any reason whatsoever.

Q. IS COLUMBIA'S PROPOSED RNA IN THE PUBLIC INTEREST?

A. No. Notwithstanding the risk/return and inappropriate conservation price signals of Columbia's proposed RNA, the Company's proposal is at odds with the most basic tenets of basic economic theory and the core of our Country's economic system. That is, in our society, business enterprises are created and exist to serve a public need for services and products demanded by consumers. Under our approach to society's scarce resources, businesses fairly compete with no guarantees of recovering their investments (or expenses). In turn, businesses with varying levels of uncertainty (risk) require varying levels of profitability. With regard to public utilities, it is generally agreed upon that, because of their monopoly status, regulation is necessary such that regulated rates should serve as a surrogate (or mirror) for competition to the greatest extent practical. As a result, the guarantee of revenue recovery contradicts our basic economic philosophy such that the compensation paid for natural gas distribution services would be nothing more than an economic tax in that additional taxes are imposed or refunded if expectations are not met. Indeed, the United States Supreme Court has decided on more than one occasion that regulated public utilities should have an opportunity to earn a fair rate of return but not a guarantee of such a return.[25] As discussed above, if the Company's proposed RNA Rider is approved, along with the multitude of other riders and automatic adjustment clauses already in place, Columbia's profits will be virtually guaranteed (at least for the residential class).

Q. HAS COLUMBIA AND THE REST OF THE LDC INDUSTRY BEEN ABLE TO REMAIN FINANCIALLY VIABLE OVER THE YEARS WITHOUT GUARANTEED REVENUE RECOVERY UNTIL RELATIVELY RECENTLY?

A. Yes. For decades, the pricing structure of natural gas LDCs has been largely volume based and not subject to revenue guarantees. The natural gas LDC industry has remained viable and has achieved, at the very least, respectable returns on their investments with this volumetric based rate structure. For example, faced with largely volumetric rate structures and no guaranteed revenue recovery in general, the Value Line group of natural gas utility companies has achieved the following average rates of return on common equity each year since 2000:

[25] See for example, Smyth v. Ames [169 U.S. 466 (1898)] and FPC v. Natural Gas Pipeline Company [315 U.S. 575 (1942)].

TABLE 11

Year	Value Line Natural Gas Utility Rate of Return on Common Equity a/
2000	11.7%
2001	12.2%
2002	11.8%
2003	12.1%
2004	11.1%
2005	12.0%
2006	12.2%
2007	11.4%
2008	11.8%
2009	12.1%
2010	11.6%
2011	10.4%
Average	11.7%

a/ Calculated per Schedule GAW-10.

While it is true that natural gas LDC's have been faced with declining usages per customer due to improvements in appliance efficiency, earnings (with revenue generated largely from volumetric based prices) have been achieved at high levels. These high earnings are largely a result of traditional rate increases, cost savings from technological advances, economies of scales due to mergers, and customer growth. Moreover, while a number of the Companies within the Value Line group of natural gas utilities presently have some form of revenue decoupling mechanisms in place in some states, the presence of such mechanisms to guarantee revenue recovery are a relatively recent occurrence and were accepted by various Commissions in different years and with different provisions and recovery mechanisms.

Q. IN ADDITION TO YOUR GENERAL CONCERNS REGARDING COLUMBIA'S PROPOSED RESIDENTIAL RATE DESIGN, DO YOU HAVE SPECIFIC CRITICISMS REGARDING THE COMPANY'S PROPOSED RNA?

A. Yes. With regard to Columbia's proposed residential RNA mechanism, there are several shortcomings in the Company's proposal. First, the proposed RNA mechanism would penalize those customers that actively and aggressively conserve their natural gas usage. This is because the prices paid through the RNA Riders are tied to the Company's overall revenue collection for the residential class. To the extent a residential customer reduces consumption through conservation, he or she will still be subject to higher bills due to the actions of others in their class or abnormalities in weather.

Second, and perhaps most important, prices paid by residential customers may be more volatile under a RNA mechanism and contrary to efficient price signals than under a traditional pricing structure. This is because of the timing lag embedded in the proposed RNA. That is, under the Company's proposed approach, there will be a two-month adjustment lag between a customer's "actual" billing month and when that month's bill is adjusted. For example, assume that December is very mild which results in an "under collection" of residential revenues. This under collection in December would result in a positive RNA (surcharge) that would be imposed and collected during February. If February is colder than normal, customers will require more gas and incur higher bills than would normally be the case. However, due to the RNA surcharge which results from two months prior, customer bills would be even higher. In my opinion, such a pricing mechanism largely abandons the economic and public policy goals of efficient pricing.

Third, the Company's RNA proposal effectively establishes monthly revenue requirements which are directly used to establish prices outside the context of rate cases. In this regard, the use of a monthly revenue requirement is at odds with traditional and accepted ratemaking in which a utility's overall (annual) revenue requirement is used as a tool to establish fair and reasonable rates.

Q. SO THAT THE IMPACTS AND IMPLICATIONS OF THE COMPANY'S PROPOSED RNA ARE FULLY UNDERSTOOD, IF IT WERE APPROVED, WHAT WOULD THE RNA MEAN TO COLUMBIA'S RESIDENTIAL CONSUMERS, THE COMPANY'S SHAREHOLDERS, AND PUBLIC POLICY?

A. With respect to consumers, one very important point that I have not yet discussed is the understandability of the rates that they are forced to pay. It is universally accepted that residential utility rates should reasonably reflect costs, provide a price signal to efficiently use natural gas, <u>and</u> be simple enough to understand. Under the Company's proposal, residential non-gas rates are so complicated and convoluted that frankly, it takes me a considerable amount of time to understand these rates conceptually. For example, the WNA mechanism in the Tariff provides only for a terse algebraic formula that no consumer could conceivably decipher as it relates to his individual usage and prices paid for natural gas distribution service. The Company's DSM (Energy Efficiency and Conservation) Rider is five pages long and is comprised of a host of algebraic formulae and adjustment factors that must be then applied to these algebraic formulae. Columbia's proposed RNA factor is contained on a single page of its Tariff but there is only a narrative description of how the RNA will be generally calculated. In short, there is absolutely no way that a residential consumer can tell what they are paying for natural gas delivery service either on an ex post or ex ante basis.

Furthermore, because of the lag inherent in the Company's proposed RNA, a consumer will quickly realize that the total price he or she pays for natural gas delivery service is not a function of, or related to, the amount of gas consumed in a given month. As such, the residential consumer will not have an accurate price signal, or incentive, in its delivery charges to efficiently use and conserve natural gas.

From shareholders perspective, the proposed RNA would provide an umbrella, or yet, another insulating mechanism to ensure revenue and income recovery. Obviously, shareholder interests favor such a mechanism as it further reduces its risks, and insulates them from any potential volatility in earnings.

From a public policy perspective, the Company's proposed RNA for all intents and purposes, abandons our society's general economic philosophy that the more of a good or service that is consumed, the more that shall be paid for, and that conservation efforts will be rewarded with lower costs paid for such products and services. Furthermore, it is often said, and generally agreed upon, that the regulation of public utilities should serve as a surrogate for competition. In competitive markets, we certainly do not see such guarantees of revenue or income recovery. Indeed, the free market system through efficient pricing and technological change serves as the best, and most efficient, conservation policy of our economy.

In summary, the Commission must constantly balance the interests of shareholders and ratepayers in all regards. However, under the Company's RNA proposal, the scales of equity and fairness are too severely tilted away from residential customers and towards shareholders. As to the need or desire for revenue, net income, and cash flow stability, I urge the Commission to consider the significant positive impacts on the Company of its existing Weather Normalization Adjustment, DSM, and AMRP Riders.

Q. WHAT IS YOUR OPINION REGARDING THE APPROPRIATENESS OF A RESIDENTIAL RATE STRUCTURE WHICH COMPRISES A MODEST FIXED MONTHLY CUSTOMER CHARGE AND A USAGE CHARGED BASED ON ALL CONSUMPTION?

A. Modern economic price theory has been extensively studied and used for more than 200 years. Moreover, regulators have considered alternative pricing structures for about a century. The residential rate structure which consists of a fixed monthly customer charge and usage charge for all consumption is tried and true, consistent with economic theory, has survived the test of time, and provides a reasonable balancing of utility shareholder and captive ratepayer interests. Nothing has significantly changed in the way that natural gas LDC's operate, incur costs, or invest in infrastructure for decades. As a result, the best residential rate structure recovers most of the utility's costs through volumetric rates and limits fixed charges to direct customer costs.

Q. WHAT IS YOUR RECOMMENDATION AS TO THE RESIDENTIAL RATE STRUCTURE?

A. As will be discussed below, I recommend a modest increase to the current residential fixed monthly customer charge along with a single block usage charge. In addition, the Company's AMRP and DSM Riders will continue as will the WNA Rider.

Q. HAVE YOU EVALUATED THE REASONABLENESS OF MR. FEINGOLD'S PROPOSAL TO INCREASE THE RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGE FROM $12.35 TO $18.50 PER MONTH?

A. Yes. Mr. Feingold conducted a customer cost analysis and calculated a residential monthly customer "cost" ranging between $22.28 and $31.93. When the average residential customer's total distribution (excluding AMRP and DSM Riders) bill of $22.53 under current rates, or $31.73 under the Company's proposed rates, is considered, we can see that Mr. Feingold's stated customer cost range simply does not pass a reasonable "smell test."[26]

Q. HAVE YOU CONDUCTED YOUR OWN ANALYSES TO DETERMINE A RESIDENTIAL "CUSTOMER" COST?

A. Yes. Customer costs should only reflect those costs that are required to connect a new customer and maintain that customers' account. The approach that I use and is widely-used in the industry and is often referred to as a "Direct Customer Cost" analysis. I have conducted a Direct Customer Cost analysis which is provided in my Schedule GAW-11 and results in a monthly cost between $8.44 and $11.48. As can be seen in my Schedule GAW-11, the higher end of this range provides for the cost of all metering as

[26] Average residential customer total distribution bill calculated per Columbia's proof of revenues provided in response to AG 1-263.

well as a full profit provision for Services, Meters, and House Regulators. The lower-end of my range excludes metering costs. The rationale for excluding metering costs is that metering is only needed to measure the volume of gas that a customer consumes, and is therefore, clearly a function of volumetric use. Indeed, the New Jersey Board of Public Utilities specifically excluded metering costs within the determination of customer charges for many years. However, I do acknowledge that the upper-end of my customer cost analysis ($11.48) is the most commonly-used and accepted approach in the industry.

Q. WHAT IS YOUR RECOMMENDATION AS IT RELATES TO THE RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGE FOR THIS CASE?

A. Although my cost analysis indicates that no increase to the current customer charge of $12.35 is warranted, I am also aware of the Commission's recent policy to improve a utility's revenue stability and improve the utility's recovery of its fixed costs as stated in its February 29, 2012 Order involving Owen Electric Cooperative in Case No. 2011-00037. In this regard, Columbia currently has significant revenue stability mechanisms in place with a rather large fixed monthly customer charge, a Weather Normalization Adjustment mechanism, an AMRP Rider that is collected on a fixed amount per customer per month, and a DSM Rider that is also collected on a fixed amount per customer per month. With all of these factors considered, I recommend a residential fixed monthly customer charge of no more than $14.00 per month, along with a rejection of Columbia's proposed RNA Rider.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	FEDERAL DISTRICT CT		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.
2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
2003	SOUTHWESTERN VIRGINIA GAS CO	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT

YEAR	CASE NAME	JURISDICTION	DOCKET NO	SUBJECT OF TESTIMONY
2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT / RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
2007	Level of Private Pass. Auto Competition	Ma. Dept. of Insur	N/A	Private Pass Auto level of competition
2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	Wa. UTC	UG-090135	Gas Rate design
2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design
2011	Arizona-American Water Company	AZ. CORP COMM	W-01303A-10-0448	Excess Capacity/Need For Facilities
2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
2012	PPL Electric	PA PUC	R-2012-2290597	Cost Allocations/Rate Design
2012	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2012-00144	WORKERS COMPENSATION RATES
2012	Credit Life Accident & Health	VA SCC		Market Structure and Performance
2012	Avista Utilities (Electric)	Wa. UTC	UE-120436	Electric rate Design
2012	Avista Utilities (Gas)	Wa. UTC	UG-120437	Gas Rate design
2012	Kentucky Utilities	Ky PSC	2012-00221	Cost Allocations/Rate Design/ Weather Normalization
2012	LG&E (Electric)	Ky PSC	2012-00222	Cost Allocations/Rate Design
2012	LG&E (Natural Gas)	Ky PSC	2012-00222	Cost Allocations/Rate Design/ Weather Normalization
2012	Columbia Gas of Pennsylvania	PA PUC	2012-2321748	Cost Allocations/Rate Design/Revenue Distribution
2013	Virginia Natural Gas - CARE Plan	VA SCC	2012-00118	Energy Conservation and Decoupling
2013	Columbia Gas of Maryland	MD OPC	9316	Cost Allocations/Rate Design
2013	Delmarva Power & Light	DE PSC	12-546	Revenue Requirement/Rate Design
2013	PacifiCorp	Wa. UTC	13-0043	Residential Customer Charges
2013	Gas-On-Gas Generic Investigation	PA PUC	2012-232-0323	Treatment of Rate Discounts
2013	Northern Virginia Electric Cooperative Pole Attachment Fees	VA SCC	2013-00055	Financial Performance

KY PSC Case No. 2013-00167
Response to AG's Data Request Set Two No. 29
Respondent: Chad E. Notestone

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO ATTORNEY GENERAL'S SUPPLEMENTAL
REQUEST FOR INFORMATION
DATED AUGUST 16, 2013

With regard to Account 303, Miscellaneous Intangible Plant, which totals $4,186,371 in the Company's class cost of service study, please provide a detailed description and cost breakdown of the specific types of plant and/or equipment included in this account

Response:

Please see Attachment A for a description and the cost breakdown of plant included in this account.

Reponse to AG Set 2-29
Attachment A

Columbia Gas of Kentucky, Inc.
Intangible Plant Balances
For the Thirteen Months Ending December 31, 2014

Line No.	Description (A)	Gas Plant Account (B)	12/31/2013 Plant Balance (C)	1/31/2014 Plant Balance (D)	2/28/2014 Plant Balance (E)	3/31/2014 Plant Balance (F)	4/30/2014 Plant Balance (G)	5/31/2014 Plant Balance (H)	6/30/2014 Plant Balance (I)	7/31/2014 Plant Balance (J)	8/31/2014 Plant Balance (K)	9/30/2014 Plant Balance (L)	10/31/2014 Plant Balance (M)	11/30/2014 Plant Balance (N)	12/31/2014 Plant Balance (O)	13 mo avg Plant Balance (P)
1	Intangible Plant - General															
2	CIAC: Install Measurement Station	303.00	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384	13,384
3	CIAC: Install Odorizer	303.00	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776	45,776
4	CIAC: Install Tap & Inlet	303.00	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188	15,188
5	Subtotal	303.00	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348	74,348
6	Intangible Plant - Misc. Software															
7	FAAR Map Viewer	303.30	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068	47,068
8	MDT Field Collections	303.30	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941	16,941
9	BRI Imaging	303.30	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102	13,102
10	PowerPlant System	303.30	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499	50,499
11	Service MDT Migration	303.30	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900	54,900
12	EMDCS	303.30	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566	34,566
13	Phase 1 - Web Based Self Service	303.30	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539	80,539
14	Phase 1 - IVR/CTI	303.30	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288	169,288
15	Gas Management System	303.30	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032	112,032
16	Phase 2 - Web Base Self Service	303.30	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515	31,515
17	MRO Software Transformation	303.30	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287	31,287
18	Phase 3 - Web Base Self Service	303.30	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039	23,039
19	RouteSmart	303.30	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703	12,703
20	Autocad Map System	303.30	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370	11,370
21	Panagon Replacement Project	303.30	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547	59,547
22	NICE - Telecom System	303.30	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953	55,953
23	Phase 2 - IVR/CTI	303.30	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805
24	Primavera Scheduling System	303.30	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604
25	Gas Measurement Streamline	303.30	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566	5,566
26	GIS Transition Milestone	303.30	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888	597,888
27	MDT Upgrade Ventyx Project	303.30	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012	363,012
28	Field Collection System	303.30	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231	162,231
29	GIS Transition Milestone	303.30	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135	109,135
30	MDT Upgrade Ventyx Project	303.30	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610	2,610
31	Panagon Replacement Project	303.30	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)	(485)
32	New Scada System	303.30	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939	133,939
33	CDC Data Warehouse	303.30	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546	50,546
34	GIS Transition Milestone	303.30	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025
35	CDC Data Warehouse	303.30	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902	3,902
36	Field Collection System	303.30	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966	30,966
37	IRTH Ticket Management	303.30	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748	8,748
38	SCADA System Upgrade	303.30	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660	76,660
39	Customer Relationship Management	303.30	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313	60,313
40	NICE Customer Feedback	303.30	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033	5,033
41	Rugged MDT Replacement	303.30	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570	5,570
42	Mobile Upgrade Project	303.30	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070
43	SCADA System Upgrade	303.30	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796	28,796
44	Call Center VOIP	303.30	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144	172,144
45	GIS Transition Milestone	303.30	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065	4,065
46	Field Collection System	303.30	820	820	820	820	820	820	820	820	820	820	820	820	820	820
47	Computer Software: 121000	303.30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
48	PowerPlant Upgrade	303.30	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581	67,581
49	Integration Center Callout Automation	303.30	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203	4,203
50	Enterprise Document Records Mgmt	303.30	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900
51	Mobile Web Phase 2	303.30	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670	122,670
52	GIS Development - 07/01/13	303.30	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616	48,616
53	Cust. Engagement Web - 07/01/13	303.30	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944
54	Business Analytics - 07/01/13	303.30	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720	51,720
55	CDC Rugged MDT - 07/01/13	303.30	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461	65,461
56	3rd Party Billing - 07/01/13	303.30	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960
57	Cust. Engagement Web - 07/01/13	303.30	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923	15,923
58	CRM Phase 2 - 07/01/13	303.30	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974	64,974
59	Data Warehousing - 07/01/13	303.30	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924	97,924
60	McJunkin Warehousing - 07/01/13	303.30	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068	7,068
61	Network Satellite - 07/01/13	303.30	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041	33,041
62	Right Start - 07/01/13	303.30	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198	16,198
63	Satellite Enclosure - 07/01/13	303.30	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970	16,970
64	Service Corp. Capital - 07/01/13	303.30	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858	14,858
65	Email Marketing Solution/CRM -12/01/13	303.30	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253	75,253
66	GPI Migration to GasSource - 12/01/13	303.30	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546

Reponse to AG Set 2-29
Attacment A

Columbia Gas of Kentucky, Inc.
Intangible Plant Balances
For the Thirteen Months Ending December 31, 2014

Line No.	Description (A)	Gas Plant Account (B)	12/31/2013 Plant Balance (C)	1/31/2014 Plant Balance (D)	2/28/2014 Plant Balance (E)	3/31/2014 Plant Balance (F)	4/30/2014 Plant Balance (G)	5/31/2014 Plant Balance (H)	6/30/2014 Plant Balance (I)	7/31/2014 Plant Balance (J)	8/31/2014 Plant Balance (K)	9/30/2014 Plant Balance (L)	10/31/2014 Plant Balance (M)	11/30/2014 Plant Balance (N)	12/31/2014 Plant Balance (O)	13 mo avg Plant Balance (P)
67	Project Planning Analytics - 12/01/13	303.30	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204	49,204
68	EDRM - 12/01/13	303.30	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758
69	Contact Center Upgrade - 12/01/13	303.30	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260	20,260
70	Safety Telematics - 12/01/13	303.30	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944	28,944
71	WSS Improvements - 12/01/13	303.30	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683	8,683
72	Pipeline Safety - 12/01/13	303.30	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838	31,838
73	GIS Development - 07/01/14	303.30								41,893	41,893	41,893	41,893	41,893	41,893	19,335
74	Cust. Engagement Web - 07/01/14	303.30								28,944	28,944	28,944	28,944	28,944	28,944	13,359
75	Business Analytics - 07/01/14	303.30								103,439	103,439	103,439	103,439	103,439	103,439	47,741
76	CDC Rugged MDT - 07/01/14	303.30								65,461	65,461	65,461	65,461	65,461	65,461	30,213
77	Enhancements/EOL Projects - 07/01/14	303.30								54,993	54,993	54,993	54,993	54,993	54,993	25,381
78	Eng/Ops Enhancements/EOL - 07/01/14	303.30								49,134	49,134	49,134	49,134	49,134	49,134	22,677
79	Regulatory Ops Enhancements - 07/01/14	303.30								24,603	24,603	24,603	24,603	24,603	24,603	11,355
80	Comm. Ops Enhancements - 07/01/14	303.30								24,603	24,603	24,603	24,603	24,603	24,603	11,355
81	NiFit Transformation - 07/01/14	303.30								452,093	452,093	452,093	452,093	452,093	452,093	208,658
82	Phase 1 DW Transformation - 07/01/14	303.30								36,802	36,802	36,802	36,802	36,802	36,802	16,986
83	Phase 1 GL Transformation - 07/01/14	303.30								46,202	46,202	46,202	46,202	46,202	46,202	21,324
84	NiFit Shared Cost - 07/01/14	303.30								165,370	165,370	165,370	165,370	165,370	165,370	76,325
85	NiFit NGD - 07/01/14	303.30								10,809	10,809	10,809	10,809	10,809	10,809	4,989
86	NiFit CDC - 07/01/14	303.30								371,268	371,268	371,268	371,268	371,268	371,268	171,354
87	Columbus Data Center - 12/01/14														14,802	1,139
88	Subtotal		3,541,830	3,541,830	3,541,830	3,541,830	3,541,830	3,541,830	3,541,830	5,017,444	5,017,444	5,017,444	5,017,444	5,017,444	5,032,246	4,298,369
89	Forecasted Retirements	303.30	(53,018)	(53,018)	(53,018)	(53,018)	(53,018)	(53,018)	(53,018)	(181,560)	(181,560)	(181,560)	(181,560)	(181,560)	(182,858)	(112,445)
90	Total		3,563,160	3,563,160	3,563,160	3,563,160	3,563,160	3,563,160	3,563,160	4,910,232	4,910,232	4,910,232	4,910,232	4,910,232	4,923,736	4,185,924
	Rounding															447
																4,186,371

KY PSC Case No. 2013-00167
Response to AG's Data Request Set One No. 284
Respondent: S. Mark Katko

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO ATTORNEY GENERAL'S FIRST REQUEST FOR INFORMATION
DATED JULY 19, 2013

284. With regard to NiSource Corporation Service Company ("NCSC"), please provide the amount charged to Columbia Gas of Kentucky for the future test year by service area or cost center as defined within the Direct Testimony of witness Taylor on Pages 7 and 8 and Attachment SMT-2, Pages 7 through 11. If the requested information is not available by service area, please provide in the greatest detail possible; e.g., by cost center, business activity, etc.

Response:

Please see the table below for the forecasted test period management fee broken down by department.

Summary Department	Functional Department	2014
NiSource Gas Distribution	Commercial Operations	$ 420,035
	Communications	136,357
	Customer Operations	2,227,865
	NGD Executive	132,380
	NGD Operations	107,890
	Operations	2,810,713
	Rates and Regulatory	245,253
	Sales and Marketing	666,774
	Supply and Optimization	83,007
NiSource Gas Distribution Total		6,830,275
Administrative Services	Facilities and Real Estate	169,807
	Information Technology	4,237,894
	Supply Chain	248,202
Administrative Services Total		4,655,902
Corporate Affairs	Corporate Affairs - Executive	22,173
	Corporate Communications	32,954
	Governmental Affairs	11,222
	Investor Relations	17,482
Corporate Affairs Total		83,830
Executive	Audit	146,950
	Office of the CEO	56,597
Executive Total		203,547
Finance	Accounting	222,403
	NGD Finance and Accounting	441,477
	F&A - IBM Billing	7,520
	Financial Planning Analysis	135,798
	Insurance	35,262
	NIPSCO Finance and Accounting	(753)
	Office of the CFO	28,606
	SOX Compliance Group	27,663
	Tax	203,069
	Treasury & Corporate Finance	140,658
Finance Total		1,241,701
Human Resources	Corporate Human Resources	175,541
	HR Operations & Revenue	225,521
	Organization Development	60,984
Human Resources Total		462,046
Legal	Compliance and Corp Secretary	215,361
	ES&S	107,994
	Legal	744,096
Legal Total		1,067,451
Other Corporate	Cost of Capital	23,901
	General	79,718
	Income Tax	18,189
	Stock and Other Compensation	390,325
Other Corporate Total		512,133
Total Gross Management Fee		15,056,885
Management Fee Transfers		(2,323,249)
Total Net Management Fee		$ 12,733,636

COLUMBIA GAS OF KENTUCKY
FEINGOLD ALLOCATION OF NCSC CHARGES
(CUSTOMER/DEMAND)

Account Code	Total Allocated Dollars	Allocation Factor	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
807	$448,996		$299,840	$146,848	$680	$0	$1,627
870	$581,195		$449,688	$119,746	$524	$622	$10,615
874	$14,303		$11,743	$2,453	$0	$0	$107
885	$0						
887	$25,297		$19,659	$5,376	$0	$0	$262
890	$28,006		$0	$13,769	$981	$442	$12,814
892	$3,615		$3,236	$369	$0	$0	$10
893	$41,408		$29,081	$12,093	$5	$59	$171
894	$77,544		$59,842	$16,158	$64	$72	$1,409
903	$1,708,570		$1,529,588	$171,407	$105	$711	$6,759
908	$64,444		$64,444	$0	$0	$0	$0
909	$54,658		$48,956	$5,669	$1	$3	$29
910	$401,266		$235,590	$61,036	$3	$14,942	$89,695
912	$37,341		$9,844	$6,654	$17	$5,831	$14,995
913	$43,364		$11,432	$7,727	$20	$6,771	$17,414
920	$0						
923	$9,203,629		$7,173,750	$1,824,125	$8,309	$11,335	$186,110
Total	$12,733,636		$9,946,695	$2,393,429	$10,710	$40,787	$342,015
	100.00%		78.11%	18.80%	0.08%	0.32%	2.69%

COLUMBIA GAS OF KENTUCKY
FEINGOLD ALLOCATION OF NCSC CHARGES
(PEAK AND AVERAGE)

Account Code	Total Allocated Dollars	Allocation Factor	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
807	$448,996		$299,840	$146,848	$680	$0	$1,627
870	$581,195		$405,629	$130,890	$525	$645	$43,506
874	$14,303		$8,949	$3,094	$0	$0	$2,260
885	$0						
887	$25,297		$11,800	$7,180	$0	$0	$6,317
890	$28,006		$0	$13,769	$981	$442	$12,814
892	$3,615		$3,236	$369	$0	$0	$10
893	$41,408		$29,081	$12,093	$5	$59	$171
894	$77,544		$50,924	$18,209	$64	$92	$8,255
903	$1,708,570		$1,529,588	$171,407	$105	$711	$6,759
908	$64,444		$64,444	$0	$0	$0	$0
909	$54,658		$48,956	$5,669	$1	$3	$29
910	$401,266		$235,590	$61,036	$3	$14,942	$89,695
912	$37,341		$9,844	$6,654	$17	$5,831	$14,995
913	$43,364		$11,432	$7,727	$20	$6,771	$17,414
920	$0						
923	$9,203,629		$6,498,068	$1,979,497	$8,310	$11,539	$706,215
Total	$12,733,636		$9,207,383	$2,564,441	$10,712	$41,034	$910,066
	100.00%		72.31%	20.14%	0.08%	0.32%	7.15%

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(SUMMARY)

	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Operating Revenue (Curr Rev)	93,147,657	59,998,782	27,032,161	76,729	590,628	5,449,358
O&M Expenses	69,768,719	40,593,226	18,579,655	79,817	2,122,786	8,393,236
Depreciation	11,548,354	7,384,556	2,090,864	25,363	56,348	1,991,222
Taxes Other Than Income	3,525,110	1,997,976	706,034	6,358	22,608	792,133
Income Taxes	906,515	1,093,980	617,291	(3,799)	(175,848)	(625,109)
Total Expenses	85,748,698	51,069,738	21,993,844	107,739	2,025,895	10,551,483
Net Operating Income	7,398,959	8,929,044	5,038,317	(31,010)	(1,435,267)	(5,102,125)
Rate Base	203,298,499	108,011,051	47,868,568	377,148	1,272,746	45,768,987
ROR (Current Rates)	3.64%	8.27%	10.53%	-8.22%	-112.77%	-11.15%
Columbia Proposed ROR	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
Return @ Columbia proposed ROR	$17,463,341	$9,278,149	$4,111,910	$32,397	$109,329	$3,931,556
Income Deficiency	$10,064,382	$349,105	($926,407)	$63,407	$1,544,596	$9,033,681
Revenue Conversion Factor	1.6489349	1.6489349	1.6489349	1.6489349	1.6489349	1.6489349
Required Rev Increase	$16,595,511	$575,652	($1,527,584)	$104,554	$2,546,937	$14,895,952

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(RATE BASE)

		Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
I. GAS PLANT IN SERVICE								
INTANGIBLE PLANT								
Organization	301	71	521	$290	$102	$1	$3	$125
Franchise and Consents	302		0					
Miscellaneous Intangible Plant	303	71	4,186,371	$2,328,240	$816,987	$8,109	$27,935	$1,005,101
Subtotal - INTANGIBLE PLANT	301-303		4,186,892	2,328,530	817,088	8,110	27,938	1,005,226
PRODUCTION PLANT								
LAND-LNG Plant	304	2	7,678	$3,152	$1,811	$5	$29	$2,681
Subtotal - PRODUCTION PLANT	325-337		7,678	3,152	1,811	5	29	2,681
DISTRIBUTION PLANT								
Land and Land Rights	374	3	4,198,404	$1,505,548	$930,155	$2,359	$46,660	$1,713,682
Structures and Improvements	375	3	8,976,851	$3,219,099	$1,988,819	$5,045	$99,766	$3,664,123
Mains	376	3	180,114,179	$64,588,944	$39,904,240	$101,219	$2,001,736	$73,518,040
M & R Station Equipment	378	3	6,150,806	$2,205,679	$1,362,709	$3,457	$68,358	$2,510,603
M & R Station Equipment - City Gate	379	3	257,909	$92,486	$57,140	$145	$2,866	$105,272
Services	380	8	106,378,091	$95,237,148	$10,859,651	$1,305	$0	$279,987
Meters	381	7	17,792,539	$12,475,475	$5,187,535	$2,557	$32,429	$94,543
Meter Install	382	7	8,444,842	$5,921,213	$2,462,151	$1,214	$15,392	$44,873
House Regulators	383	20	5,243,718	$3,703,665	$1,540,053	$0	$0	$0
House Regulator Install.	384	20	2,282,264	$1,611,975	$670,289	$0	$0	$0
Industrial M & R Station Equipment	385	21	2,899,386	$0	$1,425,483	$101,593	$45,754	$1,326,556
Industrial M & R Station Equipment - Direct	385 dir							
Other Property on Customers Premise	386		0					
Other Equipment	387	76	4,108,939	$2,338,502	$1,300,196	$452,966	$1,494	$15,781
Other Equipment - Direct	387 dir							
Subtotal - DISTRIBUTION PLANT			346,847,928	192,899,734	67,688,420	671,860	2,314,455	83,273,459

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(RATE BASE)

		Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
GENERAL PLANT								
Land and Land Rights	389		0					
Structures and Improvements	390		0					
Office Furniture and Equipment	391	64	1,771,901	$985,438	$345,793	$3,432	$11,823	$425,414
Transportation Equipment	392	64	128,576	$71,507	$25,092	$249	$858	$30,870
Stores Equipment	393		0					
Tools, Shop and Garage Equipment	394	64	2,757,957	$1,533,831	$538,226	$5,342	$18,403	$662,155
Laboratory Equipment	395	74	9,782	$5,440	$1,909	$19	$65	$2,349
Power Operated Equipment	396	64	258,255	$143,628	$50,399	$500	$1,723	$62,004
Communication Equipment	397		0					
Miscellaneous Equipment	398	64	192,820	$107,236	$37,630	$373	$1,287	$46,294
Other Tangible Plant	399		0					
Subtotal - GENERAL PLANT	389-399		5,119,291	2,847,081	999,050	9,916	34,160	1,229,084
TOTAL PLANT IN SERVICE			356,161,789	198,078,497	69,506,369	689,891	2,376,583	85,510,451
II. DEPRECIATION RESERVE								
Amortizable Plant	303	71	1,799,586	1,000,835	351,196	3,486	12,008	432,060
Distribution Land Structures & Improvements	374-375	3	4,416,561	$1,583,779	$978,488	$2,482	$49,084	$1,802,728
Distribution Mains	376	3	54,042,558	$19,379,661	$11,973,112	$30,370	$600,613	$22,058,802
Distribution M&R - General	378	3	2,844,843	$1,020,161	$630,274	$1,599	$31,617	$1,161,193
Distribution M&R - City Gate	379	3	270,760	$97,095	$59,987	$152	$3,009	$110,517
Distribution Services	380	8	57,925,307	$51,858,808	$5,913,328	$711	$0	$152,459
Distribution - Meters	381	7	4,861,118	$3,408,437	$1,417,292	$699	$8,860	$25,830
Distribution - Meters Installations	382	7	4,206,022	$2,949,108	$1,226,294	$605	$7,666	$22,349
Distribution - Regulators	383	20	1,357,729	$958,971	$398,758	$0	$0	$0
Distribution - Regulator installations	384	20	1,736,105	$1,226,220	$509,885	$0	$0	$0
Industrial M & R Station Equipment - Other	385	21	1,027,993	$0	$505,413	$36,020	$16,222	$470,337
Industrial M & R Station Equipment - Direct	385 dir		0	$0	$0	$0	$0	$0
Other Property on Customers Premises	386		0	$0	$0	$0	$0	$0
Other Equipment	387	76	1,439,627	$819,329	$455,543	$158,703	$523	$5,529
Other Equipment - Direct	387 dir		0					
General Plant	390-399	65	3,030,530	$1,685,422	$591,420	$5,870	$20,222	$727,596
Total-DEP. RESERVE (PLANT IN SERVICE)			138,958,739	85,987,826	25,010,989	240,697	749,825	26,969,402
Net Plant In Service			217,203,050	112,090,671	44,495,379	449,194	1,626,757	58,541,049

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(RATE BASE)

	Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
III. OTHER RATE BASE ITEMS							
Gas Storage Underground - NonCurrent							
Gas Stored Underground - Current	6	38,936,027	$25,295,398	$13,522,693	$34,160	$0	$83,776
Accum. Provision for Gas Lost - Underground Storage							
Materials and Supplies	74	74,783	$41,591	$14,594	$145	$499	$17,954
Working Capital	75	4,081,898	$2,282,460	$959,088	$4,055	$25,823	$810,472
Prepayments	74	433,436	$241,056	$84,586	$840	$2,892	$104,062
Deferred Income Taxes	74	(57,430,695)	($31,940,124)	($11,207,773)	($111,246)	($383,225)	($13,788,327)
CWIP		0					
Customer Deposits							
Total - OTHER RATE BASE ITEMS		(13,904,551)	(4,079,620)	3,373,188	(72,046)	(354,011)	(12,772,062)
IV. TOTAL RATE BASE (Excl. Gas Purch Working Capital)		203,298,499	108,011,051	47,868,568	377,148	1,272,746	45,768,987
Gas Purchases Cash Working Capital	131	0					
V. TOTAL RATE BASE		203,298,499	108,011,051	47,868,568	377,148	1,272,746	45,768,987

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(EXPENSES)

		Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
I. OPERATION & MAINTENANCE EXPENSE								
Other Gas Supply Expenses								
Nat Gas Field andTransmission line purchases	801-803	25	37,489,274	$25,035,413	$12,261,205	$56,816	$0	$135,839
Natural Gas City Gate	804	25	742,362	$495,751	$242,796	$1,125	$0	$2,690
Purchase Gas Cost Adjustment	805	25	1,484,724	$991,502	$485,592	$2,250	$0	$5,380
Exchange Gas	806	25	(5,196,533)	($3,470,255)	($1,699,573)	($7,876)	$-0	($18,829)
Well Expense - Purchase Gas	807	25	(4,562)	($3,047)	($1,492)	($7)	$-0	($17)
Gas Delivery/Withdraw from Storage	808	25	2,598,267	$1,735,128	$849,787	$3,938	$0	$9,415
Gas used Compressor Station	810		0					
Gas Used Other Utility	812		0					
Subtotal - Gas Supply	751-812		37,113,532	24,784,492	12,138,316	56,247	0	134,478
NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES								
Other Expenses (Including Propane Air)	824	1	1,888	$771	$443	$1	$17	$656
Subtotal - NATURAL GAS STORAGE	816-836		1,888	771	443	1	17	656
DISTRIBUTION EXPENSES								
Operation Supervision & Engineering	870	67	158,444	$88,597	$37,228	$157	$1,002	$31,459
Distribution Load Dispatching	871	17	14,970	$3,947	$2,668	$7	$2,338	$6,012
Mains and Services Expenses	874	66	2,703,223	$1,508,053	$478,987	$967	$18,888	$696,328
Meas. & Reg. Station Expenses - General	875	3	281,584	$100,976	$62,385	$158	$3,129	$114,935
Meas. & Reg. Station Expenses - Industrial	876	21	90,656	$0	$44,571	$3,177	$1,431	$41,478
Meter & House Regulator Expenses	878	7	1,555,509	$1,090,666	$453,519	$224	$2,835	$8,265
Customer Installations Expenses	879	7	1,490,068	$1,044,781	$434,439	$214	$2,716	$7,918
Other Expenses	880	67	1,079,577	$603,663	$253,659	$1,073	$6,830	$214,353
Rents	881	67	84,056	$47,001	$19,750	$84	$532	$16,690
Maint. Supervision & Engineering	885	67	14,127	$7,899	$3,319	$14	$89	$2,805
Maint. of Structures & Improvements	886	3	198,504	$71,184	$43,978	$112	$2,206	$81,024
Maint. of Mains	887	3	1,513,723	$542,821	$335,365	$851	$16,823	$617,863
Maint. of Compressor Station Equip.	888		0					
Maint. of Meas. & Reg. Station Expenses-General	889	3	286,632	$102,786	$63,503	$161	$3,186	$116,996
Maint. of Meas. & Reg. Station Expenses-Indust.	890	21	78,557	$0	$38,623	$2,753	$1,240	$35,942
Maint. of Services	892	8	296,081	$265,073	$30,226	$4	$0	$779
Maint. of Meters & House Regulators	893	29	195,215	$137,101	$57,009	$22	$276	$806

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(EXPENSES)

		Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Maint. of Other Equipment	894	67	271,608	$151,874	$63,817	$270	$1,718	$53,929
Subtotal - DISTRIBUTION EXPENSES	870-894		10,312,534	5,766,421	2,423,047	10,245	65,238	2,047,582
Total - OPERATION & MAINTENANCE EXPENSES			47,427,954	30,551,684	14,561,805	66,493	65,256	2,182,716
II. CUSTOMER ACCOUNTS EXPENSES								
Supervision	901	31	7,176	$6,083	$889	$0	$14	$189
Meter Reading Expenses	902	9	1,379,366	$1,095,520	$207,510	$19	$5,105	$71,213
Customer Records & Collection Expense	903	13	1,554,415	$1,391,581	$155,942	$96	$647	$6,149
Uncollectible Accounts	904	22	839,477	$743,155	$78,349	$225	$1,699	$16,050
Miscellaneous Customer Accounts Expense	905	31	1,973	$1,673	$244	$0	$4	$52
Office Supplies Customer Accounts	921dir	31	321	$272	$40	$0	$1	$8
Total - CUSTOMER ACCOUNTS EXPENSES	902-905		3,782,728	3,238,285	442,973	340	7,469	93,661
III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES								
Supervision	907	33	45,693	$45,092	$222	$0	$54	$326
Customer Assistance Expenses	908	14	(123,829)	($123,829)	$-0	$-0	$-0	$-0
Informational & Instructional Advertising Expense	909	10	(555)	($497)	($58)	($0)	($0)	($0)
Misc. Customer Serv. & Inform. Expen.	910	15	(4,077)	($2,394)	($620)	($0)	($152)	($911)
Office Supplies Customer Service	921	10	2,289	$2,050	$237	$0	$0	$1
Subtotal - CUSTOMER SERVICE	907-910		(80,479)	(79,578)	(219)	0	(97)	(585)
IV. SALES EXPENSES								
Supervision	911		0					
Demonstrating & Selling Expenses	912	10	(19,796)	($17,731)	($2,053)	($0)	($1)	($11)
Advertising Expense	913	10	(39,432)	($35,318)	($4,090)	($1)	($2)	($21)
Miscellaneous Sales Expenses	916		0					
Subtotal - O&M Accounts	911-916		0					
Total - SALES EXPENSES	915-916		(59,228)	(53,049)	(6,143)	(1)	(3)	(31)
Total - CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES	901-916		3,643,021	3,105,658	436,611	339	7,368	93,045

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(EXPENSES)

		Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
V. ADMINISTRATIVE & GENERAL EXPENSES								
A. Labor-Related:								
Administrative & General Salaries	920	70	1,118,082	$696,811	$254,390	$1,226	$5,633	$160,022
Office Supplies & Expenses	921	70	515,522	$321,283	$117,293	$565	$2,597	$73,783
Admin. Expenses Transferred-Credit	922	70	0	$0	$0	$0	$0	$0
Outside Services Employed	923	70	617,228	$384,669	$140,434	$677	$3,110	$88,339
Employee Pensions and Benefits	926	70	2,257,606	$1,406,984	$513,658	$2,476	$11,374	$323,114
NCSC Expenses to Columbia KY		17	12,733,636	$3,356,964	$2,269,017	$5,809	$1,988,403	$5,113,444
Subtotal - Labor Related	920-932		17,242,074	6,166,711	3,294,791	10,753	2,011,117	5,758,702
B. Plant-Related:								
Property Insurance	924	71	95,653	$53,197	$18,667	$185	$638	$22,965
Injuries and Damages	925	71	870,589	$484,176	$169,899	$1,686	$5,809	$209,019
Maintenance of General Plant	932-935	65	518	$288	$101	$1	$3	$124
Subtotal - O&M Accounts 924-925, 932			966,760	537,661	188,667	1,873	6,451	232,108
C. Other-Related:								
Franchise Requirements	927		0					
Regulatory Commission Expenses	928	69	458,995	$217,346	$91,797	$337	$30,600	$118,915
Duplicate Charges - Credit	929		0					
Misc. Gen'l Expenses	930	69	18,813	$8,908	$3,763	$14	$1,254	$4,874
Rents	931	69	11,102	$5,257	$2,220	$8	$740	$2,876
Customer Deposits Interest Expense								
Storage Interest Expense								
Total - ADMINISTRATIVE & GENERAL EXPENSES	920-931		18,697,744	6,935,884	3,581,238	12,984	2,050,162	6,117,475
TOTAL - OPERATING EXPENSES (Excl. Depr.)			69,768,719	40,593,226	18,579,655	79,817	2,122,786	8,393,236
VI. DEPRECIATION EXPENSE								
Intangible Plant	403.1	71	555,519	$308,951	$108,412	$1,076	$3,707	$133,374
Production Plant	403.2							
Natural Gas Storage Plant	403.3							
Transmission	403.4							
Distribution Structures & Improvements		3	262,006	$93,955	$58,047	$147	$2,912	$106,944
Distribution Land Structures & Improvements - Direct								
Distribution Mains	403.5	3	3,739,149	$1,340,859	$828,407	$2,101	$41,556	$1,526,226
Distribution M&R - General		68	166,683	$59,773	$36,929	$94	$1,852	$68,036

**COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(EXPENSES)**

	Allocator		Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Distribution M&R - General - Direct								
Distribution M&R - City Gate			0					
Distribution Services	403.6	8	4,914,372	$4,399,691	$501,686	$60	$0	$12,935
Distribution Services - Direct								
Distribution - Meters		7	872,069	$611,463	$254,258	$125	$1,589	$4,634
Distribution - Meters Installations		7	249,959	$175,262	$72,877	$36	$456	$1,328
Distribution - Regulators		20	159,394	$112,581	$46,813	$0	$0	$0
Distribution - Regulator installations		20	29,892	$21,113	$8,779	$0	$0	$0
Industrial M & R Station Equipment		21	133,652	$0	$65,710	$4,683	$2,109	$61,150
Industrial M & R Station Equipment - Direct								
Other Property on Customers Premises	403.7							
Distribution Other Equipment	403.8	76	149,010	$84,805	$47,151	$16,427	$54	$572
Distribution Other Equipment - Direct								
General Plant	403.9	65	316,649	$176,104	$61,795	$613	$2,113	$76,024
Amortization of Negative Net Salvage								
Total - DEPRECIATION EXPENSE	403		11,548,354	7,384,556	2,090,864	25,363	56,348	1,991,222
VII. TAXES OTHER THAN INCOME TAXES								
General Taxes								
Payroll Taxes	408.15	73	559,026	$348,396	$127,191	$613	$2,816	$80,009
Plant Related Taxes	408.17	71	2,966,084	$1,649,580	$578,843	$5,745	$19,792	$712,123
Gas Related	408.18							
Subtotal - General Taxes			3,525,110	1,997,976	706,034	6,358	22,608	792,133
TOTAL EXPENSES (excl. Gross Receipts Taxes & Gas Purchases)	408.1		47,728,651	25,191,266	9,238,238	55,291	2,201,742	11,042,113
INCOME TAXES								
Taxable Income (Current Rates):	409.1							
Oper Revenue			93,147,657	59,998,782	27,032,161	76,729	590,628	5,449,358
O&M Expenses			69,768,719	40,593,226	18,579,655	79,817	2,122,786	8,393,236
Depr.			11,548,354	7,384,556	2,090,864	25,363	56,348	1,991,222
Taxes Other Than Income			3,525,110	1,997,976	706,034	6,358	22,608	792,133
Taxable Income			8,305,474	10,023,024	5,655,607	(34,809)	(1,611,114)	(5,727,234)
Fed & State Income Tax (Current Rates)		Taxable Income	906,515	1,093,980	617,291	(3,799)	(175,848)	(625,109)

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(REVENUES)

			Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
OPERATING REVENUES								
Sales & Transportation Operating Revenues	480-485	18	92,265,950	$59,355,422	$26,803,810	$76,268	$587,082	$5,443,368
Forfeited Discounts	487	23	356,864	$284,849	$72,015	$0	$0	$0
Miscellaneous Service Revenues	483-495	16	524,843	$358,512	$156,335	$461	$3,546	$5,990
Total Operating Revenues			93,147,657	59,998,782	27,032,161	76,729	590,628	5,449,358

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(LABOR)

LABOR SUBREPORT: FUNCTIONALIZATION PHASE

	Acct	Allocator	Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
	870	67	102,588	$57,364	$24,104	$102	$649	$20,369
	871	17	11,408	$3,007	$2,033	$5	$1,781	$4,581
	874	66	1,085,114	$605,355	$192,273	$388	$7,582	$279,516
	875	3	205,781	$73,793	$45,591	$116	$2,287	$83,995
	876	21	78,489	$0	$38,589	$2,750	$1,239	$35,911
	878	7	1,194,349	$837,434	$348,221	$172	$2,177	$6,346
	879	7	1,142,375	$800,991	$333,067	$164	$2,082	$6,070
	880	67	354,452	$198,198	$83,283	$352	$2,242	$70,377
	885	67	12,690	$7,096	$2,982	$13	$80	$2,520
	886	3	3,324	$1,192	$736	$2	$37	$1,357
	887	3	606,392	$217,452	$134,346	$341	$6,739	$247,514
	888		0					
	889	3	201,401	$72,222	$44,620	$113	$2,238	$82,207
	890	21	65,269	$0	$32,090	$2,287	$1,030	$29,863
	892	8	195,886	$175,371	$19,997	$2	$0	$516
	893	29	54,694	$38,412	$15,972	$6	$77	$226
	894	67	174,432	$97,536	$40,985	$173	$1,103	$34,634
Subtotal Distribution			5,488,644	3,185,424	1,358,888	6,987	31,345	906,001
	901	31	7,176	$6,083	$889	$0	$14	$189
	902	9	173,299	$137,638	$26,071	$2	$641	$8,947
	903	13	734,136	$657,231	$73,650	$45	$306	$2,904
	907	33	11,711	$11,557	$57	$0	$14	$83
	908	14	0	$0	$0	$0	$0	$0
	910	15	0	$0	$0	$0	$0	$0
	912	10	0	$0	$0	$0	$0	$0
	920	70	1,118,082	$696,811	$254,390	$1,226	$5,633	$160,022
5. TOTAL: LABOR allocator			7,533,048	4,694,744	1,713,944	8,261	37,953	1,078,147

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION AMOUNT)

			Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Design Day	EXT	1	338,931	138,400	79,500	200	3,100	117,731
Design Day xMDS	EXT	2	337,122	138,400	79,500	200	1,290	117,731
Peak & Average xmds	EXT	3	Calc					
THRUPUT_Firm	EXT	4	22,387,194	8,000,000	4,880,375	13,844	4,738,574	4,754,401
Winter5	EXT	5	11,503,293	4,955,429	2,649,128	6,692	334,187	3,557,857
Winter5xTransport	EXT	6	7,627,661	4,955,429	2,649,128	6,692	0	16,412
Meter_Invest	EXT	7	8,453,205	5,927,077	2,464,589	1,215	15,407	44,917
Service_Invest	EXT	8	73,598,806	65,890,827	7,513,364	903	0	193,712
CUST-902	EXT	9	1,324,868	1,052,237	199,311	18	4,903	68,399
Cust_Avg	EXT	10	131,717	117,976	13,662	2	7	70
Cust_Avg X MDS	EXT	11	131,708	117,976	13,662	0	0	70
SmCust_Avg	EXT	12	131,638	117,976	13,662	0	0	0
CUST-903	EXT	13	3,063,886	2,742,927	307,375	189	1,275	12,120
CUST-908	EXT	14	1	1	0	0	0	0
CUST-910	EXT	15	346,898	203,670	52,766	3	12,917	77,542
RevenueFirm	EXT	16	86,893,375	59,355,423	25,882,956	76,268	587,082	991,646
THRUPUT	EXT	17	30,345,604	8,000,000	5,407,307	13,844	4,738,574	12,185,879
Revenues	EXT	18	92,265,952	59,355,423	26,803,811	76,268	587,082	5,443,368
NonGas_Revenue	EXT	19	55,147,858	34,567,886	14,664,003	20,014	587,082	5,308,873
House Reg	EXT	20	8,391,666	5,927,077	2,464,589	0	0	0
Ind M&R Equip	EXT	21	2,382,424	0	1,171,319	83,479	37,596	1,090,030
Write-offs	EXT	22	620,260	549,091	57,889	166	1,255	11,859
487 Direct	EXT	23	383,904	306,432	77,472	0	0	0
BILLCUST	EXT	24	1,580,609	1,415,714	163,947	24	84	840
GasCost	EXT	25	37,118,093	24,787,537	12,139,807	56,254	0	134,494
DISTL/P-C	INT	26	0					
MAINSPT-C	INT	27	0					
DISTMAIN-SERVICE-C	INT	28	0					
DISTMETER-REG-C	INT	29	33,763,363	23,712,328	9,860,028	3,771	47,821	139,415
THRUPUTxMDS	INT	30	26,087,030	8,000,000	5,407,307	13,844	480,000	12,185,879
CUST-902&903	INT	31	2,933,781	2,487,102	363,452	115	5,752	77,361
DISTPTXL-COM	INT	32	0					
908&910	INT	33	(127,906)	(126,223)	(620)	(0)	(152)	(911)
DISTPTXL-DEM	INT	34	0					
DISTL/P-D	INT	35	0					
MAINSPT-D	INT	36	0					
MAINSPT-E	INT	37	0					
DISTMAIN-SERVICE-D	INT	38	0					

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION AMOUNT)

			Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
DISTMETER-REG-D	INT	39	0					
DISTMETER-REG-E	INT	40	0					
DISTL/P-E	INT	41	0					
DISTMAIN-SERVICE-E	INT	42	0					
DISTGENTPXL-D	INT	43	0					
DISTGENTPXL-E	INT	44	0					
DISTGENPTXL-C	INT	45	0					
DISTLABOR-Dist-D	INT	46	0					
DISTLABOR-D	INT	47	0					
DISTLABOR-E	INT	48	0					
DISTLABOR-Dist-C	INT	49	0					
DISTLABOR-C	INT	50	0					
DISTLABOR-Dist-E	INT	51	0					
Income_BeforeTax	INT	52	0					
DISTPT-D	INT	53	0					
DISTPT-E	INT	54	0					
DISTPT-C (accts 380-385)	INT	55	143,040,840	118,949,476	22,145,162	106,669	93,575	1,745,958
PRODPT-D	INT	56	0					
DISTO&M-D	INT	57	0					
DISTO&M-E	INT	58	0					
DISTO&M-C	INT	59	0					
DISTREVREQ-D	INT	60	0					
DISTREVREQ-E	INT	61	0					
DISTREVREQ-C	INT	62	0					
303+ TProd +Dist Excl 374,375,387	INT	63	333,757,783	$188,167,977	$64,288,048	$219,604	$2,194,500	$78,887,655
303+ Prod+ Dist Plt		64	351,041,977	195,231,126	68,507,217	679,973	2,342,419	84,281,241
Genl Plt		65	5,119,291	2,847,081	999,050	9,916	34,160	1,229,084
Mains+Services plt		66	286,492,270	$159,826,092	$50,763,890	$102,524	$2,001,736	$73,798,027
Dist Expenses 871-879 & 886-893		67	8,704,722	$4,867,387	$2,045,273	$8,648	$55,067	$1,728,347
accts 378 & 379		68	6,408,715	2,298,165	1,419,849	3,602	71,225	2,615,875
O&M Excl gas, uncollect & other A&G		69	31,326,800	$14,834,067	$6,265,211	$22,986	$2,088,493	$8,116,043
Total Labor Excl A&G Sal & Wages		70	6,414,966	$3,997,933	$1,459,554	$7,034	$32,320	$918,125
Total Prod + Dist Plt		71	346,855,606	192,902,886	67,690,231	671,864	2,314,485	83,276,140
A&G Expenses accts (920-935)		72	18,208,834	6,704,372	3,483,458	12,626	2,017,568	5,990,810
Total Labor		73	7,533,048	4,694,744	1,713,944	8,261	37,953	1,078,147
Total Dist Plt		74	346,847,928	192,899,734	67,688,420	671,860	2,314,455	83,273,459
Total Dist O&M		75	10,312,534	5,766,421	2,423,047	10,245	65,238	2,047,582
Dist Plt Excl 387		76	602,220,300	342,738,989	190,561,232	66,388,224	218,894	2,312,962

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION AMOUNT)

		Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Memo: Include Special Contracts per Feingold definitions in Design day demand and Volumes for P&A allocator							
Design Day Demand: (Avg Jan daily usage)							
	FX1						1,819
	FX2						1,000
	FX5 (mainline)					0	
	FX7					1,290	
	SC3						13,512
Total Special Contracts for Mains						1,290	16,331
Plus Feingold Design Day for Small DS (SS) Mains						0	5,200
Large DS Design Day Demand							96,200
Total Design Day for Mains						1,290	117,731
Volumes for Mains							
Feingold included all Special Contract & DS MCF for DS/IS							
	FX1						already included
	FX2						already included
	FX5 (mainline)					0	
	FX7					480000	
	SC3						already included
Total Special Contracts for Mains						480000	0
Feingold MCF for Mains						0	12,185,879
Total MCF for Mains						480,000	12,185,879

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION PERCENT)

			Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
Design Day	EXT	1	100.0000%	40.8342%	23.4561%	0.0590%	0.9146%	34.7361%
Design Day xMDS	EXT	2	100.0000%	41.0534%	23.5820%	0.0593%	0.3827%	34.9225%
Peak & Average xmds	EXT	3	100.0000%	35.8600%	22.1550%	0.0562%	1.1114%	40.8175%
THRUPUT_Firm	EXT	4	100.0000%	35.7347%	21.7999%	0.0618%	21.1664%	21.2371%
Winter5	EXT	5	100.0000%	43.0784%	23.0293%	0.0582%	2.9051%	30.9290%
Winter5xTransport	EXT	6	100.0000%	64.9666%	34.7305%	0.0877%	0.0000%	0.2152%
Meter_Invest	EXT	7	100.0000%	70.1163%	29.1557%	0.0144%	0.1823%	0.5314%
Service_Invest	EXT	8	100.0000%	89.5270%	10.2085%	0.0012%	0.0000%	0.2632%
CUST-902	EXT	9	100.0000%	79.4220%	15.0438%	0.0014%	0.3701%	5.1627%
Cust_Avg	EXT	10	100.0000%	89.5678%	10.3722%	0.0015%	0.0053%	0.0531%
Cust_Avg X MDS	EXT	11	100.0000%	89.5739%	10.3729%	0.0000%	0.0000%	0.0531%
SmCust_Avg	EXT	12	100.0000%	89.6215%	10.3785%	0.0000%	0.0000%	0.0000%
CUST-903	EXT	13	100.0000%	89.5244%	10.0322%	0.0062%	0.0416%	0.3956%
CUST-908	EXT	14	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
CUST-910	EXT	15	100.0000%	58.7118%	15.2108%	0.0009%	3.7236%	22.3530%
RevenueFirm	EXT	16	100.0000%	68.3083%	29.7870%	0.0878%	0.6756%	1.1412%
THRUPUT	EXT	17	100.0000%	26.3630%	17.8191%	0.0456%	15.6154%	40.1570%
Revenues	EXT	18	100.0000%	64.3308%	29.0506%	0.0827%	0.6363%	5.8996%
NonGas_Revenue	EXT	19	100.0000%	62.6822%	26.5903%	0.0363%	1.0646%	9.6266%
House Reg	EXT	20	100.0000%	70.6305%	29.3695%	0.0000%	0.0000%	0.0000%
Ind M&R Equip	EXT	21	100.0000%	0.0000%	49.1650%	3.5040%	1.5781%	45.7530%
Write-offs	EXT	22	100.0000%	88.5259%	9.3330%	0.0268%	0.2023%	1.9119%
487 Direct	EXT	23	100.0000%	79.8200%	20.1800%	0.0000%	0.0000%	0.0000%
BILLCUST	EXT	24	100.0000%	89.5676%	10.3724%	0.0015%	0.0053%	0.0531%
GasCost	EXT	25	100.0000%	66.7802%	32.7059%	0.1516%	0.0000%	0.3623%
DISTL/P-C	INT	26						
MAINSPT-C	INT	27						
DISTMAIN-SERVICE-C	INT	28						
DISTMETER-REG-C	INT	29	100.0000%	70.2309%	29.2033%	0.0112%	0.1416%	0.4129%
THRUPUTxMDS	INT	30	100.0000%	30.6666%	20.7280%	0.0531%	1.8400%	46.7124%
CUST-902&903	INT	31	100.0000%	84.7746%	12.3885%	0.0039%	0.1960%	2.6369%

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION PERCENT)

			Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
DISTPTXL-COM	INT	32						
908&910	INT	33	100.0000%	98.6839%	0.4848%	0.0000%	0.1187%	0.7125%
DISTPTXL-DEM	INT	34						
DISTL/P-D	INT	35						
MAINSPT-D	INT	36						
MAINSPT-E	INT	37						
DISTMAIN-SERVICE-D	INT	38						
DISTMETER-REG-D	INT	39						
DISTMETER-REG-E	INT	40						
DISTL/P-E	INT	41						
DISTMAIN-SERVICE-E	INT	42						
DISTGENTPXL-D	INT	43						
DISTGENTPXL-E	INT	44						
DISTGENPTXL-C	INT	45						
DISTLABOR-Dist-D	INT	46						
DISTLABOR-D	INT	47						
DISTLABOR-E	INT	48						
DISTLABOR-Dist-C	INT	49						
DISTLABOR-C	INT	50						
DISTLABOR-Dist-E	INT	51						
Income_BeforeTax	INT	52						
DISTPT-D	INT	53						
DISTPT-E	INT	54						
DISTPT-C (accts 380-3	INT	55	100.0000%	83.1577%	15.4817%	0.0746%	0.0654%	1.2206%
PRODPT-D	INT	56						
DISTO&M-D	INT	57						
DISTO&M-E	INT	58						
DISTO&M-C	INT	59						
DISTREVREQ-D	INT	60						
DISTREVREQ-E	INT	61						
DISTREVREQ-C	INT	62						

COLUMBIA GAS OF KENTUCKY
AG CLASS COST OF SERVICE STUDY
(PEAK & AVERAGE METHOD AND ALL ADJUSTMENTS)
(ALLOCATION PERCENT)

		Total	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS
303+ TProd +Dist Excl 374,375,387	63	100.0000%	56.3786%	19.2619%	0.0658%	0.6575%	23.6362%
303+ Prod+ Dist Plt	64	100.0000%	55.6148%	19.5154%	0.1937%	0.6673%	24.0089%
Genl Plt	65	100.0000%	55.6148%	19.5154%	0.1937%	0.6673%	24.0089%
Mains+Services plt	66	100.0000%	55.7872%	17.7191%	0.0358%	0.6987%	25.7592%
Dist Expenses 871-879 & 886-893	67	100.0000%	55.9166%	23.4961%	0.0993%	0.6326%	19.8553%
accts 378 & 379	68	100.0000%	35.8600%	22.1550%	0.0562%	1.1114%	40.8175%
O&M Excl gas, uncollect & other A&(	69	100.0000%	47.3526%	19.9995%	0.0734%	6.6668%	25.9077%
Total Labor Excl A&G Sal & Wages	70	100.0000%	62.3220%	22.7523%	0.1097%	0.5038%	14.3122%
Total Prod + Dist Plt	71	100.0000%	55.6148%	19.5154%	0.1937%	0.6673%	24.0089%
A&G Expenses accts (920-935)	72	100.0000%	36.8193%	19.1306%	0.0693%	11.0802%	32.9006%
Total Labor	73	100.0000%	62.3220%	22.7523%	0.1097%	0.5038%	14.3122%
Total Dist Plt	74	100.0000%	55.6151%	19.5153%	0.1937%	0.6673%	24.0086%
Total Dist O&M	75	100.0000%	55.9166%	23.4961%	0.0993%	0.6326%	19.8553%
Dist Plt Excl 387	76	100.0000%	56.9126%	31.6431%	11.0239%	0.0363%	0.3841%

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER A
(LOW RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**
Rate of Return, ROR		
Number of Years for ROR		
		Plus Taxes
Annual Revenue Stream for ROR (to recover capital costs)		
Effective Tax Rate		
Other est. comparison factors; $/Mcf		
banking and balancing		
flow order occurrences		
program management time		
est. cg commodity cost difference, $/Mcf		
shrinkage		
other		
Note (see below) **Total**		

Rate/Mcf for ROR & Term

[redacted]

Rate/Mcf for ROR & Term including other comparison factors

[redacted]

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER A
(MEDIUM RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**

Rate of Return, ROR	[redacted]	
Number of Years for ROR		
		Plus Taxes
Annual Revenue Stream for ROR (to recover capital costs)		
Effective Tax Rate		

Rate/Mcf for ROR & Term
[redacted]

Other est. comparison factors; $/Mcf	
banking and balancing	[redacted]
flow order occurrences	
program management time	
est. cg commodity cost difference, $/Mcf	
shrinkage	
other	
Note (see below) **Total**	

Rate/Mcf for ROR & Term including other comparisc
[redacted]

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER A
(HIGH RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**

Rate of Return, ROR	[redacted]		
Number of Years for ROR			
Annual Revenue Stream for ROR (to recover capital costs)		**Plus Taxes** [redacted]	**Rate/Mcf for ROR & Term** [redacted]
Effective Tax Rate			

Other est. comparison factors; $/Mcf	[redacted]	**Rate/Mcf for ROR & Term including other comparison factors** [redacted]
banking and balancing		
flow order occurrences		
program management time		
est. cg commodity cost difference, $/Mcf		
shrinkage		
other		
Note (see below) **Total**		

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER C
(LOW RISK)

Competitive situation cost estimator

INPUT OUTPUT

Customer
Est. annual volume; Mcf
Primary competitor
[redacted]

Basic competitive situation Interstate bypass

Estimated capital costs to serve
Est. distance to supply source, feet
Pipe Size, inches
Price per foot, $/foot
\# of M&R stations
Other costs
Other benefits (serving mutiple customers)
Sub-total

Est. annualized O&M costs to maintain asset
TOTAL [redacted] **TOTAL CAPEX VALUE**

Rate of Return, ROR

Number of Years for ROR

Annual Revenue Stream for ROR
(to recover capital costs)

Effective Tax Rate
[redacted]

Plus Taxes
[redacted]

Rate/Mcf for ROR & Term
[redacted]

Rate/Mcf for ROR & Term including other comparison factors
[redacted]

Other est. comparison factors; $/Mcf
banking and balancing
flow order occurrences
program management time
est. cg commodity cost difference, $/Mcf
shrinkage
other
Note (see below) **Total**
[redacted]

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER C
(MEDIUM RISK)

Competitive situation cost estimator

	INPUT	OUTPUT	
Customer	[redacted]		
Est. annual volume; Mcf			
Primary competitor			
Basic competitive situation	Interstate bypass		
Estimated capital costs to serve	[redacted]		
Est. distance to supply source, feet			
Pipe Size, inches			
Price per foot, $/foot			
# of M&R stations			
Other costs			
Other benefits (serving mutiple customers)			
Sub-total			
Est. annualized O&M costs to maintain asset			
TOTAL		**TOTAL CAPEX VALUE**	
Rate of Return, ROR	[redacted]		
Number of Years for ROR			
Annual Revenue Stream for ROR (to recover capital costs)		**Plus Taxes** [redacted]	**Rate/Mcf for ROR & Term** [redacted]
Effective Tax Rate			
Other est. comparison factors; $/Mcf			**Rate/Mcf for ROR & Term including other comparison factors** [redacted]
banking and balancing	[redacted]		
flow order occurrences			
program management time			
est. cg commodity cost difference, $/Mcf			
shrinkage			
other			
Note (see below) **Total**			

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER C
(HIGH RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		TOTAL CAPEX VALUE
Rate of Return, ROR	[redacted]	
Number of Years for ROR		
Annual Revenue Stream for ROR (to recover capital costs)		Plus Taxes [redacted]
Effective Tax Rate		
Other est. comparison factors; $/Mcf	[redacted]	
banking and balancing		
flow order occurrences		
program management time		
est. cg commodity cost difference, $/Mcf		
shrinkage		
other		
Note (see below) **Total**		

Rate/Mcf for ROR & Term
[redacted]

Rate/Mcf for ROR & Term including other comparison factors
[redacted]

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

[redacted]

	POD Site	Land & R/W	Pipe	Bore	Total
Plastic	[redacted]				
Steel					

Mike Pierce - CKY Ashland April 2012

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER E
(LOW RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**

		Plus Taxes	Rate/Mcf for ROR & Term
Rate of Return, ROR	[redacted]		
Number of Years for ROR			
Annual Revenue Stream for ROR (to recover capital costs)		[redacted]	[redacted]
Effective Tax Rate			

Other est. comparison factors; $/Mcf

		Rate/Mcf for ROR & Term including other comparison factors
banking and balancing	[redacted]	[redacted]
flow order occurrences		
program management time		
est. cg commodity cost difference, $/Mcf		
shrinkage		
other		
Note (see below) **Total**		

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER E
(MEDIUM RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**
Rate of Return, ROR	[redacted]	
Number of Years for ROR		
		Plus Taxes
Annual Revenue Stream for ROR (to recover capital costs)		
Effective Tax Rate		

Rate/Mcf for ROR & Term

[redacted]

Rate/Mcf for ROR & Term including other comparison factors

[redacted]

Other est. comparison factors; $/Mcf	
banking and balancing	[redacted]
flow order occurrences	
program management time	
est. cg commodity cost difference, $/Mcf	
shrinkage	
other	
Note (see below) **Total**	

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GAS OF KENTUCKY
COLUMBIA BYPASS THREAT COST ANALYSIS
CUSTOMER E
(HIGH RISK)

Competitive situation cost estimator

	INPUT	OUTPUT
Customer	[redacted]	
Est. annual volume; Mcf		
Primary competitor		
Basic competitive situation	Interstate bypass	
Estimated capital costs to serve	[redacted]	
Est. distance to supply source, feet		
Pipe Size, inches		
Price per foot, $/foot		
# of M&R stations		
Other costs		
Other benefits (serving mutiple customers)		
Sub-total		
Est. annualized O&M costs to maintain asset		
TOTAL		**TOTAL CAPEX VALUE**
Rate of Return, ROR	[redacted]	
Number of Years for ROR		
		Plus Taxes
Annual Revenue Stream for ROR (to recover capital costs)		
Effective Tax Rate		
Other est. comparison factors; $/Mcf	[redacted]	
banking and balancing		
flow order occurrences		
program management time		
est. cg commodity cost difference, $/Mcf		
shrinkage		
other		
Note (see below) **Total**		

Rate/Mcf for ROR & Term

[redacted]

Rate/Mcf for ROR & Term including other comparison factors

[redacted]

NOTE: Negative value = COH more expensive

Source: Company response to AG 1-282.

COLUMBIA GA[illegible] KENTUCKY
COMPARISON OF COLUMBIA AND AG PROPOSED CLASS REVENUE DISTRIBUTION

Schedule G[illegible]

Class	Rate	Current Delivery Revenue 1/	Columbia Proposed Increase	Pct Change	OAG Proposed Step 1 Remove Discounts	Remaining	Pct Increase	Step2 equal PCT	Total Pct Increase
GS-Res									
	GSR	$26,452,187	$9,127,701	34.51%				$7,647,932	28.91%
	GIR	$7,776	$0	0.00%				$2,248	28.91%
	IN4	$65	$0	0.00%				$19	28.91%
	IN5	$226	$0	0.00%				$65	28.91%
	LG2-Res	$196	$0	0.00%				$57	28.91%
	LG3	$188	$0	0.00%				$54	28.91%
	LG4	$114	$0	0.00%				$33	28.91%
	GTR Choice Resid	$7,812,283	$2,681,382	34.32%				$2,258,710	28.91%
	Total Residential	$34,273,035	$11,809,083	34.46%				$9,909,118	28.91%
GS-Other									
	G1C	$7,402	$0	0.00%				$2,140	28.91%
	IN3	$401	$0	0.00%				$116	28.91%
	LG2-Comm	$256	$0	0.00%				$74	28.91%
	GSO	$8,777,294	$2,648,860	30.18%				$2,537,716	28.91%
	GTO	$4,885,626	$1,489,091	30.48%				$1,412,546	28.91%
	GDS	$920,855	$303,263	32.93%				$266,240	28.91%
	Total GS-Other	$14,591,834	$4,441,214	30.44%				$4,218,833	
IUS									
	IUS	$19,678	$6,450	32.78%				$5,689	28.91%
ML/SC									
	DS3	$75,045	$0	0.00%				$21,697	28.91%
	FX2	$53,421	$0	0.00%	$141,020			$15,445	292.89%
	FX5	$308,765	$0	0.00%				$89,271	28.91%
	FX7	$203,271	$0	0.00%	$36,073			$58,770	46.66%
	SAS	$0	$0	--				$0	
	Total ML/SC	$640,502	$0	0.00%	$177,093			$185,184	56.56%
DS/IS									
	IS	$27,947	($501)	-1.79%				$8,080	28.91%
	DS	$4,288,475	$276,773	6.45%				$1,239,896	28.91%
	FX1	$55,037	$0	0.00%	$136,395			$15,912	276.74%
	SC3	$883,188	$0	0.00%	$381,468			$255,350	72.10%
	Total DS/IS	$5,254,647	$276,272	5.26%	$517,863			$1,519,239	38.77%
Total Company		$54,779,696	$16,533,019	30.18%	$694,956	$15,838,063	28.91%	$15,838,063	30.18%

1/ Includes AMRP Revenue

Value Line Natural Gas Utilities
Rates of Return on Common Equity
(2000-2011)

Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	All Years
AGL Resources	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	
Atmos Energy Corp.	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	
Laclede Group	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	
New Jersey Resources	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	
Northwest Natural Gas	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	
Piedmont Natural Gas	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	
South Jersey Industries	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	
Southwest Gas	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	
UGI Corp.	17.6%	22.5%	23.8%	17.6%	14.1%	18.2%	16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	
WGL Holdings	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	
AVERAGE	**11.7%**	**12.2%**	**11.8%**	**12.1%**	**11.1%**	**12.0%**	**12.2%**	**11.4%**	**11.8%**	**12.1%**	**11.6%**	**10.4%**	**11.7%**
STANDARD DEVIATION													**0.54%**

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

Note: Actual 2012 results are not available for all companies as of May 1, 2013. Therefore, data does not reflect 2012 results.

Columbia Gas of Kentucky
OAG Determination of Residential Customer Costs

	W/ Profit Provision	W/O Metering Costs
Gross Plant:		
Services	$95,237,148	$95,237,148
Meters	$12,475,475	
Meter Installations	$5,921,213	
House Regulators	$3,703,665	$3,703,665
House Regulator Installations	$1,611,975	$1,611,975
Total Gross Plant	**$118,949,476**	**$100,552,788**
Depreciation Reserve:		
Services	$51,858,808	$51,858,808
Meters	$3,408,437	
Meter Installations	$2,949,108	
House Regulators	$958,971	$958,971
House Regulator Installations	$1,226,220	$1,226,220
Total Depreciation Reserve	**$60,401,544**	**$54,043,999**
Total Net Plant	**$58,547,932**	**$46,508,789**
Operation & Maintenance Expenses:		
Oper Meter & House Reg	$1,090,666	
Oper Customer Install Exp	$1,044,781	$1,044,781
Maint Services	$265,073	$265,073
Maint Meters & House Reg	$137,101	
Meter Reading Expense	$1,095,520	
Cust. Records & Collection Exp.	$1,391,581	$1,391,581
Total O & M Expenses	**$5,024,722**	**$2,701,435**
Depreciation Expense:		
Services	$4,399,691	$4,399,691
Meters	$611,463	
Meter Installations	$175,262	
House Regulators	$112,581	$112,581
House Regulator Installations	$21,113	$21,113
Total Depreciation Expense	**$5,320,110**	**$4,533,385**
Revenue Requirement:		
Interest @ 5.67%	$1,586,649	$1,260,388
Equity return @9.00%	$2,752,163	$2,186,239
Federal Tax @ 35%	$1,481,934	$1,177,205
State Tax @ 6.00%	$270,261	$214,688
O & M Expenses	$5,024,722	$2,701,435
Depreciation Expense	$5,320,110	$4,533,385
Subtotal Revenue Requirement	**$16,435,839**	**$12,073,340**
Uncollectible @ 0.568963%	$94,049	$69,086
Total Revenue requirement	**$16,529,888**	**$12,142,426**
Number of Bills	**1,439,306**	1,439,306
Monthly Cost	**$11.48**	**$8.44**

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF COLUMBIA GAS)
OF KENTUCKY, INC. FOR AN ADJUSTMENT) CASE NO. 2013-00167
OF RATES FOR GAS SERVICE)

AFFIDAVIT OF GLENN A. WATKINS

)
State of Virginia)
City of Richmond)

Glenn A. Watkins, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this 10th day of September, 2013.

Jennifer R Dolen
NOTARY PUBLIC

My Commission Expires: 10-31-14
Commission ID: 7315146

JENNIFER R. DOLEN
COMMONWEALTH OF VIRGINIA
Expires 10-31-14
ID# 7315146
NOTARY PUBLIC