BEFORE THE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION	]	
OF KANSAS GAS SERVICE, A DIVISION	]	KCC Docket No. 06-KGSG-1209-RTS
OF ONEOK, INC., FOR ADJUSTMENT	]	
OF ITS NATURAL GAS RATES IN THE	]	
STATE OF KANSAS	]	

DIRECT TESTIMONY OF

ANDREA C. CRANE

RE: REVENUE REQUIREMENTS
AND COST OF CAPITAL

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

September 27, 2006

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is One North Main Street, P.O. Box 810, Georgetown, Connecticut 06829.

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

A. I am Vice President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 230 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony is included in Appendix A.

Q. What is your educational background?

A. I received a Masters degree in Business Administration, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On or about May 15, 2006, Kansas Gas Service ("KGS" or "Company"), a division of ONEOK, Inc., filed an Application with the Kansas Corporation Commission ("KCC" or "Commission") seeking a rate increase of $73.3 million. The Company's request would result in an increase of approximately 35.9% over retail distribution sales revenue at present rates. On a total revenue basis, including gas recovery revenues, the Company's request would result in an increase of approximately 10.6%.

The Columbia Group, Inc. was engaged by The State of Kansas, Citizens' Utility

Ratepayer Board ("CURB") to review the Company's Application and to provide recommendations to the KCC regarding the Company's cost of capital and revenue requirement claims. Also on behalf of CURB, Mr. Brian Kalcic is providing testimony that addresses the Company's proposed rate design and Mr. Michael J. Majoros is providing testimony that addresses depreciation issues.

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues in the Company's filing are a) operating expense increases and rate base increases for various regulatory assets associated with pensions and other post-retirement benefit costs; b) the Company's proposal for a rate rider to track certain employee benefit costs; and c) the Company's request for an 11.25% return on equity.

III. <u>SUMMARY OF CONCLUSIONS</u>

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending December 31, 2005 is a reasonable test year to use in this case to evaluate the reasonableness of the Company's claim.
2. The Company has a cost of equity of 9.65% and an overall cost of capital of 8.03%

(see Schedule ACC-2).[1]

3. KGS has pro forma test year rate base of $678,462,649 (see Schedule ACC-8).

4. The Company has pro forma operating income at present rates of $28,672,185 (see Schedule ACC-17).

5. KGS has a pro forma, revenue requirement deficiency of $42,824,276 (see Schedule ACC-1). This is in contrast to the Company's claimed deficiency of $73,300,788.

6. Any adjustments resulting from the testimony of Mr. Majoros should be considered by the Commission to be in addition to those contained in this testimony.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company utilized the following capital structure and cost of capital in its filing:

	Percent	Cost Rate	Weighted Cost
Common Equity	52.48%	11.25%	5.90%
Long Term Debt	47.52%	6.24%	2.97%
Total	100.00%		8.87%

Q. Are you recommending any adjustments to this capital structure or cost of capital?

1 Schedules ACC-1, ACC-34, and ACC-35 are summary schedules, ACC-2 to ACC-7 are cost of capital schedules,

A. I am not recommending adjustments to the Company's capital structure or cost of debt. However, I am recommending an adjustment to the Company's claimed cost of equity. Specifically, I am recommending a cost of equity of 9.65% for KGS.

Q. How did you develop your recommended cost of equity?

A. The KCC has traditionally relied upon the Discounted Cash Flow Model ("DCF") as the primary mechanism to determine cost of equity for a regulated utility. Therefore, in determining an appropriate return on equity for KGS, I have relied primarily upon the DCF. The DCF method is based on the following formula:

$$\text{Return on Equity} = \frac{D_1}{P_0} + g$$

where "D_1" is the expected dividend, "P_0" is the current stock price, and "g" is the expected growth in dividends.

The DCF methodology is generally applied to a comparable group of investments, usually to a group of companies that provide the same utility service as the utility service for which rates are being set. In order to determine a comparable group of companies, I utilized the same comparable group as that selected by the Company. To determine an appropriate dividend yield for the comparable companies, i.e. the expected dividend divided by the current price, I calculated the dividend yield of each of the comparable companies under two scenarios. First, I calculated the dividend yield using the average of the stock prices for each

ACC-8 to ACC-16 are rate base schedules, and ACC-17 to ACC-33 are operating income schedules.

company over the past twelve months. The use of a dividend yield using a twelve-month average price mitigates the effect of stock price volatility for any given day. Based on the average stock prices over the past twelve months, and the current dividend for each company, I determined an average dividend yield for the comparable group of 3.76%, as shown in Schedule ACC-5. I also calculated a current annualized dividend yield at September 12, 2006, which showed an average dividend yield for the comparable group of 3.60%. This calculation is also shown in Schedule ACC-5. Based on these determinations, I recommend that a dividend yield of 3.76% be used in the DCF calculation. My recommended dividend yield was then increased by ½ of my recommended growth rate, as determined below, to reflect the fact that the DCF model is prospective and dividend yields may grow over the next year. Increasing the dividend yield by ½ of the prospective growth rate is commonly referred to as the "half year convention."

Q. How did you determine an appropriate growth rate?

A. The actual growth rate used in the DCF analysis is the dividend growth rate. In spite of the fact that the model is based on dividend growth, it is not uncommon for analysts to examine several growth factors, including growth in earnings, dividends, and book value.

Various growth rates for the companies within my comparable group are shown in Schedule ACC-6 and summarized below:

Past 5 Years - Earnings	8.65%
Past 5 Years - Dividends	2.45%
Past 5 Years - Book Value	6.42%
Past 10 Years - Earnings	6.07%
Past 10 Years - Dividends	2.33%
Past 10 Years - Book Value	4.64%
Estimated Next 5 Years - Earnings	5.96%
Estimated Next 5 Years - Dividends	3.33%
Estimated Next 5 Years - Book Value	5.81%

Q. Why do you believe that it is reasonable to examine historic growth rates as well as projected growth rates when evaluating a utility's cost of equity?

A. I believe that historic growth rates should be considered because security analysts have been notoriously optimistic in forecasting future growth in earnings. At least part of this problem in the past has been the fact that firms that traditionally sell securities are the same firms that provide investors with research on these securities, including forecasts of earnings growth. This results in a direct conflict of interest since it has traditionally been in the best interest of securities firms to provide optimistic earnings forecasts in the hope of selling more stock. As a result of this practice, the Wall Street investment firms agreed to a $1.4 billion settlement with securities regulators. Pursuant to that settlement, ten major Wall Street law firms agreed to pay $1.4 billion to investigating state regulators and the United States Securities and Exchange Commission ("SEC"). Approximately $900 million of this amount constituted fines. The remainder was earmarked for various education and independent research activities. In addition, firms were required to sever the links between their stock research activities and their investment banking activities. Therefore, earnings growth forecasts should be analyzed cautiously by state regulatory commissions.

Q. Based upon your review, what growth rate do you recommend be utilized in the DCF calculation?

A. Based on my review of this data, I believe that a growth rate of 6.0 % should be utilized. This recommended growth rate is above the projected five-year growth rates in earnings, dividends, or book value for the comparable group. Moreover, my recommended growth rate is higher than the historic ten-year growth rates in dividends or book value, and comparable to the historic ten-year growth rate in earnings. Accordingly, I believe that a growth rate of 6.0% for the comparable group is reasonable.

Q. What cost of equity is produced by the DCF methodology?

A. My analysis indicates a cost of equity using the DCF methodology of 9.87%, as shown below:

Dividend Yield	3.76%
Growth in Dividend Yield (1/2 X 6.0% X 3.76%)	0.11%
Expected Growth	6.00%
Total	9.87%

Q. Did you also calculate a cost of equity based on the CAPM methodology?

A. Yes, I did.

Q. Please provide a brief description of the CAPM methodology.

A. The CAPM methodology is based on the following formula:

Cost of Equity = Risk Free Rate + Beta (Risk Premium)

or

$$\text{Cost of Equity} = R_f + B(R_m - R_f)$$

The CAPM methodology assumes that the cost of equity is equal to a risk-free rate plus some market-adjusted risk premium. The risk premium is adjusted by Beta, which is a measure of the extent to which an investor can diversify his market risk. The ability to diversify market risk is a measure of the extent to which a particular stock's price changes relative to changes in the overall stock market. Thus, a Beta of 1.00 means that changes in the price of a particular stock can be fully explained by changes in the overall market. A stock with a Beta of 0.60 will exhibit price changes that are only 60% as great as the price changes experienced by the overall market. Utility stocks have traditionally been less volatile than the overall market, i.e., their stock prices do not fluctuate as significantly as the market as a whole, and therefore their Betas have generally been less than 1.0.

Q. How did you calculate the cost of equity using the CAPM?

A. My CAPM analysis is shown in Schedule ACC-7. First, I used a risk-free rate of 4.92% for the yield on long-term U.S. Government bonds, which was the rate at September 14, per the Statistical Release by the Federal Reserve Board. Over the past year, this rate has ranged from 4.51% to 5.25%. In addition, I used the average Beta for the proxy group. This resulted in an average Beta of 0.83. Finally, since I am using a long-term U.S. Government bond rate as the risk-free rate, the risk premium that should be used is the historic risk premium of stocks over the rates for long-term government bonds. According to the 2006 Ibbotson Associates' publication, *2006 Yearbook: Stocks, Bonds, Bills, and Inflation*, the risk premium of stocks over long-term government bonds using geometric mean returns is 4.9%.

Q. What is the difference between a geometric and an arithmetic mean return?

A. An arithmetic mean is a simple average of each year's percentage return. A geometric mean takes compounding into effect. As a result, the arithmetic mean overstates the historic return to investors. For example, suppose an investor starts with $100. In year 1, he makes 100% or $100. He now has $200. In year 2, he loses 50%, or $100. He is now back to $100.

The arithmetic mean of these transactions is 100% - 50% or 50%/ 2 = 25% per year. The geometric mean of these transactions is 0%. In this simple example, it is clear that the geometric mean more appropriately reflects the real return to the investor, who started with $100 and who still has $100 two years later. The use of the arithmetic mean would suggest that the investor should have $156.25 after two years ($100 X 1.25 X 1.25), when in fact the investor actually has considerably less. Therefore, a geometric mean return is a more appropriate measure of the real return to an investor, if it is used as I am using it here, i.e., to develop an historic relationship between long-term risk free rates and market risk premiums. Some utilities have criticized me in the past for using a geometric, rather than an arithmetic mean return, arguing that the arithmetic mean should be used when estimating future returns. However, in my case, I am not using the mean to develop an expected outcome, I am simply using the mean returns to develop an historic relationship. Therefore, the geometric mean is the appropriate measure, as illustrated in the above example.

Q. What is the Company's cost of equity using a CAPM approach?

A. Given a long-term risk-free rate of 4.92%, a Beta of 0.83, and a risk premium of 4.9%, the CAPM methodology produces a cost of equity of 8.99%, as shown on Schedule ACC-7.

Risk Free Rate + Beta (Risk Premium) = Cost of Equity

4.92% + (0.83 X 4.9%) = 8.99%

Q. Based on your analysis of the DCF and CAPM results, what cost of equity are you recommending in this case?

A. The DCF methodology and the CAPM methodology suggest that a return on equity of 8.99% to 9.87% would be appropriate. Since I recognize that the Commission has generally relied primarily upon the DCF, I have weighted my results with a 75% weighting for the DCF methodology and a 25% weighting for the CAPM methodology. This results in a cost of equity of 9.65%, as shown below:

DCF Result	9.87% X 75% =	7.40%
CAPM	8.99% X 25% =	2.25%
Total		9.65%

Q. What is the overall cost of capital that you are recommending for KGS?

A. As shown on Schedule ACC-2, I am recommending an overall cost of capital for KGS of 8.03%. However, the actual required return on equity for KGS could be considerably less than this rate.

Q. Why do you believe that a reasonable cost of capital for KGS might be less than 9.65%?

A. The DCF and CAPM analyses do not consider the significant risk mitigation mechanisms that are in place at KGS, or that are being requested in this case. For example, KGS has a COGR, insulating the Company and its shareholders from any risk due to rising gas costs. In addition, the Company has a Weather Normalization Clause ("WMC"), which eliminates risk associated with weather variations. This clause significantly reduces the overall revenue risk for KGS. In addition, in this case, KGS is requesting approval for an optional rate structure that would result in very high fixed charges. This rate design is another risk mitigation strategy, shifting the remaining revenue risk from shareholder to ratepayers.

With regard to rate base, the Kansas Legislature has enacted legislation that allows gas utilities to implement annual surcharges between rate cases to recover costs associated with a wide variety of infrastructure improvement projects. This legislation reduces a utility's risk of capital expenditures, ensuring recovery between rate cases in many instances.

On the expense side, KGS is permitted to recover its actual gas costs on a dollar-for-dollar basis. This removes the largest single cost component from the Company's base revenue requirement. In addition, KGS now recovers the majority of its uncollectible costs through the COGR, so all risk related to these costs has been removed. The Company has an Ad Valorem Tax Surcharge Rider, which permits a pass-through of actual ad valorem taxes between rate cases. In addition, in this case, the Company is requesting a rider to true-up certain employee benefit costs, removing yet another significant risk from shareholders.

With each of these mechanisms, KGS eliminates more and more of its risk. Given this diminishing risk, the actual required return on equity for KGS is probably significantly less than 9.65%, and may instead be approaching a risk-free rate.

V. RATE BASE ISSUES

Q. What test year did the Company utilize to develop its rate base claim in this proceeding?

A. The Company selected the test year ending December 31, 2005. In addition, the Company made various post-test year adjustments to its actual balances at the end of the test year.

A. Mid-Continent Market Center ("MCMC") Assets

Q. Please provide a brief background of the MCMC assets.

A. The MCMC was formed in 1995 when Western Resources, the former owner of the KGS gas assets, received KCC approval to transfer certain transmission assets to an affiliated entity, MCMC. The transferred assets consisted of major transmission lines, as well as compressor stations, storage fields and gathering systems connected to the transmission lines.

Once these assets were transferred from rate base, the utility paid MCMC an annual fee of approximately $16.4 million in return for the services that had formerly been performed internally. This fee was designed to equate to the revenue requirement that would have been in place had the transfer not taken place. In July 2000, the KCC approved a request by KGS to recover a portion of these costs through the cost of gas rate ("COGR") clause and began collecting $10.9 million through the COGR. On August 1, 2001, this fee was reduced by $727,166 to reflect the fact that MCMC had reduced storage available for KGS for the storage year beginning April 1, 2001.

In January 2002, KGS requested KCC authorization to transfer back to KGS certain assets that had previously been transferred to MCMC. Except for the storage facilities, most of the MCMC assets were transferred back to KGS.

Approximately $93.2 million in gross utility plant in service, and approximately $44.2 million of net plant, was transferred back from the MCMC to KGS during 2002. Approximately $31.2 million of this gross utility plant in service related to assets that were constructed by the MCMC after the assets were originally transferred from the utility in 1995. These new assets fall into two categories: assets that replaced or upgraded existing facilities, and new assets that were constructed in order to enhance the ability of MCMC to transact business with other pipelines. Among the most significant assets included in the latter category were two new pipelines: 1) a $9.2 million, 20" pipeline from Yaggy to Bushton; and 2) a $3.3 million, 24" pipeline from Hutchinson to Yaggy.

In its last base rate case, the Company proposed to include these assets in its regulated jurisdictional rate base. In that case, I recommended that the KCC exclude from rate base those assets that were constructed since 1995 that were built in order to enhance the ability of MCMC to transact business with other pipelines. This amounted to approximately $23.1 million in gross plant.

Q. What was the basis for your recommendation?

A. My recommendation was based on the fact that the MCMC assets were transferred from the utility because the Company believed that it would be more profitable if those assets could be removed from the regulation of the KCC. It was generally believed that without the regulation of the KCC, the Company would be able to maximize the value of those assets to the benefit of shareholders. However, by 2002, it became clear that the opportunities envisioned by the Company did not materialize and instead the Company decided to return those assets to the regulation of the KCC.

As I stated in the last case, Kansas ratepayers should not be paying for plant that was constructed in order to maximize the potential of an unregulated affiliate. Western Resources, and later ONEOK, took steps to remove the MCMC assets from KCC regulation when they felt that such actions maximized shareholder benefit. Later, when the opportunities for the MCMC diminished, ONEOK sought the safety of KCC regulation and recovery of all MCMC costs from ratepayers. A regulated utility's rate base should not be used as a safety net for failed business ventures. While the Company attempted in the last case to justify the inclusion of these assets in rate base, on the basis that such plant may provide benefits to retail ratepayers, the fact remains that these facilities were constructed to enhance revenue opportunities for MCMC and not to ensure the provision of safe and adequate utility service to Kansas ratepayers.

Q. In the last case, did you recommend the exclusion of all MCMC assets from rate base?

A. No, I did not. I only recommended the elimination of assets constructed since the transfer by MCMC to enhance its ability to transact business with other pipelines. I did not exclude from rate base any new plant that replaced or updated facilities that were originally in place prior to the transfer from the utility.

Q. What was the resolution of this issue in the last case?

A. The last base rate case was resolved by stipulation. Pursuant to that stipulation, KGS was permitted to recover depreciation expense and ad valorem taxes on all of the MCMC assets. However, the Company was not permitted to include in rate base approximately $22.3 million of plant that had been constructed since the transfer. In addition, the Company was not permitted to recover operating expenses on those assets that were excluded from rate base.

Q. What is the Company requesting in this case?

A. In this case, the Company is requesting the inclusion in rate base of another $13.1 million of the amount excluded by the KCC in its last case. KGS has made an adjustment to its filing to eliminate the remaining $9.2 million in gross plant. In addition, KGS has made an adjustment to include the operating costs associated with the plant that it has included in rate base.

Q. What do you recommend?

A. I continue to recommend that this plant be excluded from rate base. The plant included by the Company in its rate base claim relates largely to three projects: the 24" Hutchinson to Yaggy pipeline, the 20" Yaggy to Bushton pipeline, and the 12" Satanta outlet west pipeline. These projects were not constructed to serve regulated retail jurisdictional ratepayers. Moreover, while some benefit may now be accruing to some retail ratepayers from these assets, the resolution in the last case already provides KGS with recovery of depreciation expense and ad valorem taxes related to this plant. Thus, KGS is already receiving a return <u>of</u> this plant from ratepayers. The agreement in the last case that the Company would forego a return <u>on</u> this plant continues to be a reasonable compromise for this plant that was constructed by the Company in order to enhance its non-jurisdictional activities. Therefore, I recommend that this plant continue to be excluded from rate base. My adjustment is shown in Schedule ACC-9.

B. Corporate Plant Allocation

Q. How are common corporate plant and common operating costs allocated to the Company from ONEOK?

A. The Distrigas allocation methodology is used by ONEOK to allocate costs that are common to all divisions and affiliates and therefore cannot be directly assigned to any particular unit or allocated based on cost-causative factors. The Distrigas allocation is the average of three factors: gross plant and investment, operating income, and labor expense. In its filing, KGS used a Distrigas allocation of 15.56% for costs allocated from ONEOK.

Q. Are you recommending any adjustment to the Distrigas allocation factor?

A. Yes, I am. In a supplemental response to KCC-1, the Company indicated that the pro forma Distrigas allocation factor had been updated effective April 1, 2006 to reflect the acquisition of an additional share of Guardian Pipeline by ONEOK. Since this is a known and measurable change to the test year, the Distrigas formula should be updated to reflect a lower allocation to KGS. At Schedule ACC- 10, I have made an adjustment to revise the allocation of corporate plant to KGS based on the updated Distrigas allocation factor.

Q. Do you have any additional comments about the Distrigas allocation methodology?

A. Yes, I do. This methodology is acceptable as an allocation methodology when joint and common costs are being allocated among a number of similar types of entities, such as utilities in different states. The methodology is less acceptable when used to allocate costs among regulated and non-regulated entities, as is the case here. This is because there can be significant variations in the allocation percentages depending upon the type of business receiving the allocations. For example, utilities are much more capital intensive than many other types of business ventures, resulting in a relatively high percentage of costs being allocated based on investment. Similarly, utilities often have more employees than their non-regulated affiliates. Parent companies can maintain low staffing levels at unregulated subsidiaries by retaining a large corporate or service company staff. Similarly, start-up ventures, which may have little investment, few employees, and little income may require a disproportionate amount of corporate resources. For all these reasons, the Distrigas methodology may allocate a disproportionately large share of joint and common costs to regulated utilities.

Q. Have you accepted the use of the Distrigas methodology in this case?

A. Yes, I have. However, the KCC should be aware of the problems inherent in the use of the Distrigas methodology. For example, ONEOK has energy marketing and trading operations that require substantially less investment and fewer employees than ONEOK's gas distribution business. However, energy marketing and trading activities can be very profitable and therefore corporate support may be of even greater benefit to the ONEOK energy and trading operations than would be apparent from the use of the Distrigas allocation methodology. For example, according to the 2005 Annual Report, the three gas distribution companies provided just over 14% of the Company's operating income in 2005, yet just one of these three companies, KGS, is allocated over 15% of the common costs. Therefore, while I have not made a specific adjustment in this testimony relating to the allocation methodology, I recommend that the KCC reconsider its use of the Distrigas allocation methodology and determine if it is still acceptable, given the evolution that has occurred in ONEOK's business segments.

C. Accumulated Depreciation

Q. Are you recommending any adjustment to the Company's claim for accumulated depreciation?

A. Yes, consistent with my recommendation above to exclude approximately $13.1 million of the MCMC assets from rate base, I have also reflected an adjustment to exclude from rate base the accumulated depreciation on these assets. My adjustment is shown in Schedule ACC-11.

In addition, at Schedule ACC-12, I have made an adjustment to revise the amount of accumulated depreciation on corporate common plant allocated to KGS by the Distrigas allocator. Since this factor has been updated effective April 1, 2006, it is necessary to update the allocation of accumulated depreciation on corporate assets. This is consistent with my utility plant-in-service adjustment relating to corporate assets that was discussed above.

D. Employee Benefit Assets

Q. Please describe the regulatory assets included in rate base related to the Company's employee benefits expense.

A. The Company has included a net regulatory asset of $67,779,899 in its rate base claim. This net regulatory asset is composed of a regulatory asset of $75,742,318 relating to pension expense, a regulatory liability of $5,854,465 relating to other post-employment benefit ("OPEB") costs, and a regulatory liability of $2,107,954 relating to the Supplemental

Executive Retirement Plan ("SERP").

Q. Do these claims have a significant impact on the Company's overall rate request?

A. Yes, they do. On a stand-alone basis, the pension asset is responsible for $11.2 million of the Company's claim. This is a staggering amount, particularly when one realizes that the pension asset has not been funded by investors at all. In fact, the pension "asset" is an accounting convention that did not require funding by any party. Therefore, it is difficult to see how the Company can claim a working capital requirement related to this "asset". Similarly, ratepayers did not supply the capital to fund the OPEB and SERP regulatory liabilities, as will be discussed below. Therefore, the notion that ratepayers deserve a return on their capital is equally untenable.

Q. How was the pension asset created?

A. The accounting for pension costs is described by Robin Hagerty in her testimony and generally I agree with Ms. Hagerty's discussion of the manner in which pension costs are determined pursuant to Statement of Financial Accounting Standards No. 87 ("SFAS 87"). However, I disagree with Ms. Hagerty regarding whether a pension asset should be included in rate base.

Each year, a company's pension expense is calculated. This calculation determines the amount of pension expense that must be recognized for financial reporting purposes, based on numerous factors. The calculation considers the accumulated amount that should have been accrued at the present time based on the demographics of a company's employees, the age at which such employees are likely to retire, the expected future return on pension plan assets, assumptions regarding future payroll levels, assumptions regarding an appropriate discount rate, and other factors. When calculating the annual payroll expense, certain gains and losses are amortized over a multi-year period. This amortization helps to mitigate significant fluctuations that can occur from year-to-year in pension plan earnings.

Thus, the calculation of the pension expense is a snapshot at a point in time. It is impacted by what has happened in the past as well as what is expected to happen in the future. In addition, there is a gradual true-up of past estimates with actual results over time. Pursuant to FAS 87, a pension expense can be either positive or negative. If it is positive, then the pension plan is under-funded at a given point in time from an actuarial perspective and additional amounts must be accrued. In that case, ratepayers are required to provide for additional recovery of costs in rates. If the pension expense is negative under SFAS 87, then the plan is over-funded at a given point in time, i.e., the accumulated annual accruals exceed the amount required pursuant to SFAS 87, and ratepayers receive a credit in cost of service due to the fact that the pension expense was higher than necessary in prior years. The actual cash funding of the plan, i.e., the amount of cash contributions to the dedicated trust that must be made by KGS, is governed by the requirements of the Employee Retirement Income Security Act ("ERISA") and Internal Revenue Service ("IRS") regulations.

A negative pension expense means that the Company actually collected its pension expense early from ratepayers, i.e., it collected more from ratepayers in prior years than was necessary. This does not mean that the Company did anything wrong or illegal. The negative pension expense, which is what gives rise to the pension asset, occurs because pension expense is based on estimates of several variables, including future market returns. Since estimates are involved in this process, the FAS 87 mechanism has a built-in rolling true-up in that each year's pension expense is based on what actually happened in the past relative to prior projections, as well as on projections for the future. A negative pension expense means that the Company's estimates in the past resulted in higher pension expense being booked than was, based on the actual market returns, actual demographics of employees, actual pension benefits, etc.

The Company is essentially giving back to ratepayers this over-collection through the pension credit. These are amounts that have already been charged to pension expense and now are essentially being refunded. Therefore, ratepayers have prepaid these amounts. If there is any cash working capital implication, these amounts should be deducted from rate base, not added to rate base, since these credits represent a prepayment of pension expense.

The booking of a pension asset results from accounting requirements that have no relationship to the ratemaking treatment afforded these costs. Therefore, there is no regulatory rationale for including a pension asset in rate base.

Q. Did the Company include a pension asset in rate base in its last base rate case?

A. No, it did not. This is the first case in which the Company is requesting that a pension asset be included in rate base, although the Company has had a pension asset on its books for quite some time, since at least 1997, as shown in the response to CURB-92. KGS offers no reason why a pension asset should be included in rate base now, when no such asset was included in the Company's past rate base claims.

Q. Has the Company actually funded the pension plan since its last base rate case?

A. No, it has not. As shown in the response to CURB-52, KGS has not made any cash contributions to the pension trust fund since sometime prior to 2000.

Q. Does the pension asset represent amounts that ratepayers owe to the Company?

A. No, it does not. The Company claims that the pension asset represents investor-supplied funds on which the Company should earn a return. However, no such amounts were provided by investors. In fact, since at least 2000, and possibly well before, investors have provided no funding for the pension fund. Yet, during this time, the pension asset has grown from approximately $57 million to $75 million, without one cent of investor funds being contributed.

If anything, the pension asset represents amounts that were prepaid by ratepayers, since the pension credits (or negative pension expenses) that give rise to the pension asset indicate that at some point in the past more funds were collected from ratepayers than were actually necessary.

Q. Similarly, does the OPEB regulatory liability, which the Company treats as a rate base deduction, represent amounts that have been funded by ratepayers?

A. No, it does not. As stated by Mr. Whitlock, the OPEB liability "represents the unfunded portion of the liability...". Since the liability is <u>unfunded</u>, ratepayers could not have provided this capital. Once again, the OPEP liability, like the pension asset, is an accounting vehicle to report the accumulation of accounting transactions that have occurred over time. This regulatory liability does not generate cost-free capital and it should not be used to reduce rate base. Similarly, the SERP regulatory liability also does not represent cost-free capital either. Therefore, I recommend that the regulatory liabilities associated with OPEB and SERP costs be excluded from rate base, just as I recommend that the regulatory asset associated with pension costs be eliminated from rate base. My adjustments are shown in Schedule ACC-13.

E. <u>Mobile Home Park Replacement</u>

Q. Please describe the Company's rate base claim associated with the mobile home park replacement program.

A. In January 2001, the Company received KCC authorization to defer certain costs associated with a five-year program to upgrade gas facilities at mobile home parks around the State. As stated in the KCC's Order approving the deferral,

> ...within the certificated area of Kansas Gas Service there are 212 mobile home parks with an estimated 7,600 gas customers in which

> the natural gas piping systems are owned by the park while the gas in the piping system is owned by the LDC...the Replacement Program will eliminate a significant safety hazard within the state while allowing the residents of these mobile home parks to have the same standards of service and reliability as other customers in Kansas Gas Service's certificated territory.[2]

The KCC authorized KGS to defer all costs expended on the program and permitted the Company to earn a carrying charge of 8.9339%, the authorized rate of return allowed in the prior KGS base rate case, Docket No. 193,305-U.

In its last case, Docket No. 03-KGSG-602-RTS, the Company included in rate base $6.4 million of utility plant-in-service for mains and services associated with these upgrades at mobile home parks. The Company's claim was based on actual expenditures through June 2002 and forecasted additions through June 30, 2003. In addition, the Company included a three-year amortization of deferred costs including return, depreciation expense and ad valorem taxes.

Q. What was your recommendation in the last case with regard to this issue?

A. In the last case, I did not oppose the Company's request to include this plant in rate base. However, my testimony reflected updated actual costs through December 2002. In addition, I used the average monthly additions for the last quarter of 2002 as a proxy for expenditures during the first half of 2003. I also recommended that the deferred costs be amortized over seven years instead of the three years being proposed by KGS.

2 Order Approving Stipulation and Agreement and Accounting Order, Docket No. 01-KGSG-429-ACT, page 4,

Q. How was this issue addressed in the Stipulation in Docket No. 03-KGSG-602-RTS?

A. The Stipulation is silent on this issue.

Q. What has the Company included in this case for costs associated with the mobile home park program?

A. In this case, the Company has made a claim for capital expenditures from September 2002 through December 2005, when the program was completed. In addition, the Company has included carrying costs on deferred charges through January 2007. Finally, since the Stipulation in Docket No. 03-KGSG-602-RTS was silent on the issue of the cost of capital for KGS, the Company has continued to reflect the carrying charge of 8.9339%. KGS is requesting to include the deferred costs of $1,886,646 as a regulatory asset to rate base. In addition, the Company is again requesting a three-year recovery period for these costs.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am. I am recommending that the capital expenditures from September 2002 through June 2003 be excluded from the calculation of carrying costs. This time period was already included in the Company's claim, and in CURB's recommendation, in the last case. Since the Stipulation in Docket No. 03-KGSG-602-RTS is silent with regard to this issue, one can only assume that the rates agreed to in that Stipulation were sufficient to resolve this issue

January 2, 2001.

with respect to costs incurred through June 30, 2003.

Q. Are you recommending any adjustment to the carrying cost rate included by the Company in this case?

A. No, I am not. The carryings costs included by the Company were based on the capital costs allowed in Docket No. 193,305-U. Even though capital costs have declined significantly since that time, the Stipulation in the last case did not specify an overall rate of return. The Company requested a return of 9.3% in that case, while CURB recommended an overall return of 7.16%. Since the Stipulation does not specify a return, I have accepted the Company's stated return from Docket No. 193,305-U as an appropriate carrying cost since the last base rate case. I have also accepted the Company's claim for a three-year amortization for deferred charges.

Q. Should the deferred cost balance at January 1, 2007 be included in rate base as a regulatory asset?

A. No, it should not. The Company is already being granted extraordinary ratemaking treatment for these costs, since it had authorization to defer the return, depreciation, and ad valorem taxes during the construction period. The Order in 01-KGSG-429-ACT specifically provides for deferral of costs until the program is completed, and "until Kansas Gas Service's next rate case filing." No mention is made of permitting the Company to accrue carrying costs on these expenditures until they are fully recovered. In addition, the return being granted to the Company on these assets is based on capital cost rates that were established several years ago, when capital costs were significantly higher than they are today. Finally, I am accepting the Company's proposal to recover these costs over three years. Thus, these costs will not be subject to a long recovery period and will be largely, or fully, amortized by the time of the Company's next base rate case. For all these reasons, I recommend that the Company's request to include the unamortized balance in rate base be denied. This recommendation is also consistent with the Company's claim in the last base rate case, which does not appear to have included rate base treatment for deferred costs during the proposed amortization period. My adjustment is shown in Schedule ACC-14.

F. <u>Cash Working Capital</u>

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives customer revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense quarterly, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do companies always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Did the Company provide a lead /lag study in support of its cash working capital claim?

A. Yes, it did. The Company's cash working capital claim is summarized at Section 6, Schedule 6-H of its filing. KGS is requesting a cash working allowance of $11,324,676.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am. As demonstrated in the lead/lag study, the entire cash working capital claim results from inclusion of purchased gas costs in the study. If purchased gas costs are excluded, then the lead/lag study would demonstrate that no cash working capital allowance is necessary. In fact, in the absence of purchased gas costs, the Company's lead/lag study results in a negative cash working capital requirement of ($13,350,689).

Q. Did KGS include purchased gas costs in its cash working capital claim in the last case?

A. No, it did not. In the last case, the Company did not provide a lead/lag study, but instead used the $1/8^{th}$ formula method. In calculating its cash working capital requirement based on this methodology, KGS specifically excluded gas costs from the Operating and Maintenance costs subject to the $1/8^{th}$ cash working capital allowance. Thus, the Company's inclusion of gas costs in its cash working capital claim in this case represents a departure from past practice.

Q. What other concerns do you have with the inclusion of gas costs in the Company's lead/lag study?

A The Company's lead/lag study assumes that each month customers are paying for gas purchased to serve them in the month being billed. The Company has included an expense lag for gas costs of 31.26 days in its study, which reflects a service lag of approximately 15.2 days and a payment lag of approximately 16.06 days. KGS is also reflecting a revenue lag of 43.41 days. Therefore, the Company is assuming that the revenue received, on average, 43.41 days after the midpoint of the service period is intended to compensate them for expenses paid, on average, 31.26 days after services were received. However, KGS has a purchased gas adjustment mechanism that is based on two factors: estimated gas costs for a twelve-month period and an actual cost adjustment true-up factor. Therefore, in any given month, there is likely to be either an under-recovery or over-recovery of gas costs. The Company's lead/lag study incorrectly assumes a matching of monthly revenues and expenses with a 12.15 day net lag (43.41

day revenue lag - 31.26 day expense lag). However, in any particular month, the revenue received by the Company may be paying for gas purchased in the past, or it may be paying for gas that is still to be purchased in the future.

Because of the special nature of purchased gas adjustment clauses, gas costs are frequently excluded from the cash working capital calculation. This is because it is very difficult at any point in time to determine if the Company is being compensated for prior costs, current costs, or future costs. In fact, as previously noted, KGS did not include any claim for cash working capital associated with purchased gas costs in its last base rate case.

Q. What do you recommend?

A. I recommend that the KCC exclude from rate base the Company's claim for cash working capital associated with purchased gas costs, consistent with the treatment in the Company's last base rate case. The Company has not demonstrated that there is any cash working capital requirement associated with these costs. In fact, due to the nature in which the COGR operates, there may be no cash working capital requirement generated by these costs. Nor has the Company demonstrated that the KCC should deviate from its past practice in this regard. KGS has not provided any testimony in support of its proposal that the KCC change the way it has traditionally handled cash working capital associated with purchased gas costs, i.e., to exclude these costs from the Company's cash working capital requirement due to the nature of the purchased gas adjustment clause.

Q. What cash working capital allowance have you included in your pro forma rate base recommendation?

A. Removal of gas expenses from the lead/lag study results in a negative cash working capital requirement of ($13,350,689). My adjustment is shown in Schedule ACC-15.

G. Accumulated Deferred Income Taxes ("ADIT")

Q. Are you recommending any adjustments to the Company's claim for accumulated deferred income taxes?

A. Yes, I am recommending two adjustments, both of which relate to deferred income taxes associated with corporate plant. First, the Company allocated these deferred income taxes to KGS, based on the Distrigas allocation factor of 15.56%. Since that factor has now been updated to 15.19%, it is necessary to make an adjustment to reflect the revised allocator. My adjustment is shown in Schedule ACC-16.

Second, in its workpapers to Adjustment WC 2, the Company applied the Distrigas allocation to the ADIT liability, before pro forma adjustments. This has the effect of increasing ADIT allocated to KGS. Since the ADIT liability is a rate base deduction, the effect of this error is to understate the Company's rate base. Therefore, at Schedule ACC-16, I have also corrected this error by applying the revised Distrigas allocation factor of 15.19% to the ADIT balance after adjustments.

Q. Have you also made an adjustment to ADIT relating to your recommended adjustment to eliminate certain MCMC assets?

A. No, I did not. An adjustment to ADIT relating to disallowance of the MCMC assets may be appropriate, but I do not have sufficient data to quantify such an adjustment at this time. If the Company provides the necessary data, I will reflect this additional adjustment, if appropriate.

H. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base from $785,037,901 as reflected in its filing, to $678,462,649 as summarized on Schedule ACC-8.

VI. OPERATING INCOME ISSUES

A. As-Available Gas Margins and Capacity Release Revenues

Q. How did the Company reflect as-available gas margins and capacity release revenues in its revenue requirement?

A. With regard to as-available gas margins, 75% of these margins are credited to the COGR and used to reduce gas costs passed through to ratepayers, while the remaining 25% are retained by shareholders.[3] With regard to capacity release revenues, 50% of these revenues are credited to ratepayers and shareholders retain the remaining 50%.[4]

Q. Are you recommending any adjustment to the Company's treatment of these margins?

A. As long as the Company has a COGR, any change in the treatment of these margins would likely impact the COGR, and not base rates. Therefore, I am not making any specific recommendation at this time. However, I note that these margins have increased significantly over the past several years. For example, in the 1998-1999 timeframe, shareholders retained less than $2 million of as-available gas sales margins. By 2005, the test year in this case, shareholders retained $6.6 million of margins, which is almost 10% of the Company's requested utility operating income in this case. Therefore, the margins currently being retained by the Company may be much greater than those envisioned by the KCC when it established the current sharing formula. Accordingly, I recommend that the KCC reexamine this sharing formula, either in this case or as part of the Company's COGR filing. Given the staggering amounts that ratepayers are now paying for gas, I question whether it makes sense for shareholders to retain any of these margins. If ratepayers are paying 100% of the gas costs, it seems blatantly unfair that they do not receive 100% of the margins from as-available gas sales and capacity releases. I recommend that the KCC reconsider its sharing formula in light of the significant increase in gas costs as well as the significant increase in the margins being retained by shareholders.

3 Response to CURB-89.

B. Salaries and Wages

Q. How did the Company develop its payroll claim in this case?

A. KGS's claim is based on the actual payroll expense incurred during the test year. The Company then made adjustments to annualize salaries for employees that either left the Company or were transferred; to annualize salaries for new employees that joined the Company during the test year; to annualize the effect of actual payroll increases effective July 2005 for union employees and January 2006 for non-union employees; and to annualize the effect of payroll increases anticipated for union personnel in July 2006.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending one adjustment relating to the July 2006 payroll increase for union personnel. I understand that the union has not yet signed a new contract with KGS. Therefore, at this time, we do know what the impact of that contract will be. Accordingly, the proposed increase included in the Company's claim is neither known nor measurable. Moreover, this increase did not take place in the test year and was not even scheduled to take place until six months after the test year-end. For all these reasons, I recommend that the Company's claim for this post-test year union increase be denied. My adjustment is shown in Schedule ACC-18.

4 Response to CURB-90.

Q. Did you also make adjustments relating to a corresponding reduction in 401K costs and payroll tax expenses?

A. Yes, I did. In developing its payroll expense claim, the Company included adjustments to increase its 401K costs to reflect contributions associated with the higher, pro forma payroll expense. The Company's 401K adjustment was based on a contribution rate of 5.13%. Thus, at Schedule ACC-18, I have also made an adjustment to reduce 401K expense, based on applying the contribution rate of 5.13% to my pro forma payroll expense adjustment.

In addition, KGS included a payroll tax adjustment, based on a weighted payroll tax expense rate of approximately 7.14%. Therefore, at Schedule ACC-18, I have also included an adjustment to reduce the Company's pro forma payroll tax expense. To quantify my payroll tax adjustment, I applied the Company's weighted tax ratio of 7.14% to my recommended payroll expense adjustment.

C. Incentive Payments

Q. Please describe the Company's incentive awards programs.

A. The Company has four incentive plans for its employees, as described in the response to CURB-38. First, the Long Term Incentive Plan is intended to "give the Company's eligible employees and non-employee directors an interest parallel to the interests of the Company's shareholders generally." This plan includes "...the granting of two or more independent long-term incentive vehicles. In 2005, ONEOK, Inc. granted restricted stock units and performance share units."

Second, the Short-Term Incentive Plan "provides eligible employees with a direct financial interest in the performance and profitability of the Company and its individual business units. Third, Presidents Awards, or Project Bonus, provides additional incentive when recognition of an employee's contribution should go beyond the incentive provided under the Annual Employee Incentive Plan. Fourth, Project Pay provides an incentive to employees who participate in important projects with a set objective and duration in addition to or instead of their regular duties." The Project Pay program became effective in 2006.

Q. How much is included in the Company's pro forma expense claim relating to incentive plans?

A. According to the response to KCC-94, the Company's filing includes $3,666,767 in direct KGS charges and $3,054,431 in amounts allocated to KGS from ONEOK. Thus, the total amount of incentive costs included in the Company's filing is $6,721,201. It is my understanding that the Company's filing includes accruals that were made during the test year relating to incentive payments. The actual incentive payments relating to the test year were generally paid out in 2006.

Q. Did the actual incentive payments vary from the accruals reflected in the test year?

A. Yes, they did. The Company provided conflicting information in some cases, but it appears that there were significant variations between the amounts accrued and actual payments made. In response to KCC-166, the Company provided the actual incentive payments made relating to test year performance. That response indicates that KGS actually incurred incentive plan costs of $2,290,700 relating to direct employees and $720,303 (15.56% of $4,629,200) in allocated charges from ONEOK.

Q. Do you believe that these incentive awards are appropriate?

A. No, I do not. I have several concerns about these programs, especially as designed and implemented by KGS. For example, providing employees with a direct financial interest in the profitability of the Company is an objective that would benefit shareholders, but it does not benefit ratepayers. The Annual Employee Incentive Plan is based on criteria established by the Chief Executive Officer. These performance objectives are heavily weighted toward corporate performance, such as return on invested capital and earnings per share. In fact, the return criteria could be well above that approved by regulatory agencies, including the KCC. Incentive award criteria for 2006 includes a minimum 11.25% return on invested capital, well above the overall return likely to be awarded in this case.

Incentive payment awards that are based largely on earnings criteria may violate the principle that a utility should provide safe and reliable utility service at the lowest possible cost. This is because these plans require ratepayers to pay higher compensation costs as a consequence of high corporate earrings, a spiral that does not directly benefit ratepayers, but does benefit shareholders and the management to whom such awards are granted.

Q. How did the incentive payments made in the test year compare with earlier years?

A. As shown in the response to KCC-94, KGS incentive payments in the test year were higher than payments in either of the two prior years. Moreover, the payments from ONEOK were significantly higher than in prior years:

	KGS Direct	ONEOK (Assumes Allocation of 15.56% for each year)
2005	$2,290,700	$720,303
2004	$2,107,500	$614,230
2003	$1,515,500	$470,846

The officers of ONEOK continued to receive very sizable bonuses. According to the information provided in the Company's 2006 Proxy Statement, in the test year ONEOK's Chairman of the Board, President, and Chief Executive Officer received a bonus of $1,674,000, which was more than twice his annual salary of $750,000. Moreover, this bonus has doubled in just two years. In addition to his salary and bonus, Mr. Kyle also received $745,048 in restricted stock awards and $132,373 in "other compensation". In fact, all five individuals listed in the proxy statement received bonuses that were in excess of their annual salaries, as well as restricted stock awards and other compensation.

Incentive compensation plans tied to corporate performance result in greater enrichment of company personnel as a company's earnings reach or exceed targets that are predetermined by management. It should be noted that it is the job of regulators, not the shareholders or company management, to determine what constitutes a just and reasonable rate of return award to shareholders in a regulated environment. Regulators make such a determination by establishing a reasonable rate of return award on rate base in a base rate case proceeding.

Allowing a utility to charge for additional return that is then distributed to employees as part of some plan to divide extraordinary profits violates all sense of fairness to the ratepayers of the regulated entity. It is certain to result in burdensome and unwarranted rates to its ratepayers, and also violates the principles of sound utility regulation, particularly with regard to the requirement for "just and reasonable" utility rates.

Q. What would be the appropriate response by the KCC if the earnings of KGS were in excess of its authorized rate of return?

A. If the KCC determined that these excess earnings were expected to continue, the appropriate response would be to initiate a rate investigation, and, if appropriate, to reduce the utility's rates.

Q. What do you recommend?

A. Since a significant portion of the Company's incentive plan costs is based on the overall corporate performance of ONEOK and/or KGS, I recommend that the incentive awards granted under these plans be shared equally between ratepayers and shareholders. This recommendation will require the Board of Directors to establish incentive compensation plans that shareholders are willing to finance, in part. As long as ratepayers are required to pay 100% of the costs of these incentive plans, then there is no incentive for management to control these costs. This is especially true since it is the management of the Company that primarily benefits from such plans. Therefore, I recommend that the KCC disallow 50% of these incentive costs.

Q. How did you quantify your adjustment?

A. My adjustment is based on a 50% disallowance of the payments actually made by the Company that relate to the test year. Since the Company's claim is based on accrued costs, rather than actual payments, my adjustment reflects the difference between 50% of the actual incentive payments made and the total costs accrued by KGS. My adjustment is shown in Schedule ACC-19.

D. Mid-Continent Market Center Operating Costs

Q. Please describe your adjustment relating to MCMC costs.

A. As discussed in the Rate Base section of this testimony, KGS is requesting that certain MCMC assets, specifically excluded from rate base in the last case, be included in rate base in this case. The Company has also made a corresponding adjustment to include operating costs associated with those assets in its pro forma expense claim.

Since I am recommending that the MCMC assets excluded from rate base in the last case continue to be excluded, I have made a corresponding adjustment to exclude the operating costs associated with those assets from my pro forma revenue requirement recommendation. My adjustment is shown in Schedule ACC-20.

E. Mobile Home Park Deferrals

Q. What adjustment are you recommending to the Company's claim for amortization of deferred costs associated with the Mobile Home Park Program?

A. As also discussed in the Rate Base section of this testimony, KGS has included a three-year amortization of deferred costs associated with certain upgrades at mobile home parks. These deferred costs include return on assets, depreciation expense, and ad valorem taxes. I am recommending that the Company's claim be adjusted to eliminate capital expenditures from September 2002 to June 2003, on the basis that such costs were addressed explicitly in testimony in the Company's last base rate case. The Stipulation in Docket No. 03-KGSG-602-RTS should already implicitly provide for recovery of these costs. Therefore, I have revised the Company's claim to include only those capital costs incurred from July 2003 to the present. My adjustment reduces the total amount of the Company's deferral from $1,886,647 to $1,272,902. While I am not recommending any adjustment to the Company's request for a three-year amortization period, the lower deferral balance will result in a reduction to the annual amortization expense. My adjustment is shown in Schedule ACC-21.

F. Rate Case Costs

Q. Please describe the Company's rate case cost claim.

A. In its filing, KGS requested recovery of rate case costs for the current case of $1,564,180. These costs are composed of the following:

Legal Expense	$ 200,000
Depreciation Study	$ 100,000
Rate Design	$ 150,000
Return on Equity	$ 50,000
OBEPs	$ 50,000
Notification	$ 25,000
Qualitative Research	$ 25,000
MFR Preparation	$ 250,000
KCC Staff	$ 500,000
KCC Docket Expense	$ 25,000
CURB	$ 125,000
Postage, Printing, Supplies	$ 64,180
Total	$1,564,180

The Company is requesting a three-year amortization period for these costs.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am. The Company's claim represents an increase of over 23% from the actual rate case costs of $1,267,083 incurred in its last base rate case. The prior docket was the first base rate case since ONEOK acquired the gas properties from Western Resources. Therefore, there was a certain level of education necessary for all parties in that case that does not exist here. Moreover, there were also more contentious issues raised in that case, including a challenge to the Company's proposed depreciation rates. It was also the first base rate case to address the issue of the MCMC assets. For a variety of reasons, I believe that the current case should be significantly less complex than Docket No. 03-KGSG-602-RTS.

Q. What do you recommend?

A. I recommend that the KCC approve rate case costs of no more than $1,267,083, the amount that the Company spent in its last base rate case. I am not recommending any adjustment to the Company's request for a three-year amortization period. My adjustment is shown in Schedule ACC-22.

G. Common Corporate Costs

Q. Are you recommending any adjustment to the common corporate costs allocated to KGS from ONEOK?

A. I am recommending one adjustment. In Adjustment IS 19, the Company allocated common corporate costs based on the Distrigas allocation factor of 15.56%. As noted, that factor has since been updated to 15.19%. Therefore, at Schedule ACC- 23, I have made an adjustment to reallocate common corporate costs, based on the updated allocation factor of 15.19%.

H. Legal Costs

Q. Are you recommending any adjustment to the Company's claim for legal costs?

A. Yes. In response to KCC-91, the Company indicated that, based upon discussions with Staff, it had identified $331,803 of legal expenses at the ONEOK level that should not have been allocated to KGS. These expenses were allocated to KGS through the Distrigas allocation factor, resulting in an allocation of $51,629. Therefore, at Schedule ACC-24, I have made an adjustment to eliminate these costs from the Company's pro forma expense claim.

I. Aircraft Expense

Q. Did the Company eliminate all expenses associated with its aircraft from its revenue requirement claim?

A. KGS apparently intended to eliminate these costs from its claim in this case. In developing its allocation of corporate assets to KGS, the Company specifically excluded plant-in-service related to aircraft, as shown in the workpapers to Adjustment PLT 3. In addition, in Adjustment IS 22, KGE eliminated operating and maintenance costs associated with the aircraft. However, in response to KCC-101, the Company acknowledged that the operating expense adjustment to eliminate costs associated with aircraft was understated by $33,540. Therefore, at Schedule ACC-25, I have made an adjustment to remove $33,540 of expense associated with aircraft from the Company's claim.

J. <u>Donations and Contributions</u>

Q. Did the Company remove donations and contributions from its revenue requirement claim?

A. KGS generally eliminated 50% of charitable contributions from its claim. It also removed lobbying costs and membership dues for memberships that do not provide a benefit to ratepayers. However, in the response to KCC-40, the Company indicated that additional costs should have been eliminated. Specifically, the Company stated that its filing contained $6,800 for golf sponsorships that should have been eliminated, as well as $375 for Junior Achievement funding, half of which should have been eliminated. Accordingly, at Schedule ACC-26, I have made an adjustment to eliminate the costs incurred for golf sponsorships as well as 50% of the Junior Achievement costs.

K. <u>Injuries and Damages Expense</u>

Q. Are you recommending any adjustments to the Company's claim for injuries and damages expenses?

A. Yes, I am. While KGS did not propose any adjustment to its actual test year costs for injuries and damages expense, the Company's test year claim was very high relative to historic levels. In its filing, KGS included injuries and damages expense of $2,420,321, significantly higher than the actual costs incurred in any of the three prior years, as shown below:

Year	Injuries and Damages Expense
2002	$1,618,269
2003	$1,265,344
2004	$1,489,457
2005	$2,420,321

I am recommending that the Company's claim be revised to reflect a three-year average of injuries and damages expense. These costs fluctuate from year-to-year. Therefore, a three-year average is more representative of prospective costs than is the use of costs in any particular year. This is especially true in this case, given the high test year costs relative to historic levels. My adjustment is shown in Schedule ACC-27.

L. Corporate Image Advertising

Q. Are you recommending any adjustment to the Company's claim for advertising costs?

A. Yes, I am recommending that corporate image advertising costs of $3,848 be disallowed. Corporate image advertising should not be included in a regulated utility's revenue requirement. The purpose of such advertising is to promote the institution, in this case KGS and ONEOK, and their shareholders. Such advertising is designed to favorably influence opinions about the Company. These ads constitute "soft-lobbying" of ratepayers on behalf of the Company. This advertising can also be used to enhance the attractiveness of offerings made by unregulated affiliates of the utility. Such advertising is not necessary for the provision of regulated utility service and should not be paid for by ratepayers. At Schedule ACC-28, I have made an adjustment to eliminate corporate image advertising costs from rates.

Q. How did you identify the amount of corporate image advertising included in the Company's claim?

A. To quantify the amount of corporate image advertising costs included in the Company's claim, I relied upon KGS's response to KCC-42. This response specified the amount of "Corporate Image Advertising" included by the Company in regulated accounts during the test year.

M. <u>Lobbying Expenses</u>

Q. Are you recommending any adjustment to the Company's claim for lobbying expenses?

A. Yes, I am. The Company indicated in its filing that it had removed all lobbying costs. However, in response to KCC-139, KGS identified $13,738 in direct KGS costs and $5,649 in costs allocated from ONEOK that relate to Government Affairs. I am recommending that these costs be disallowed. My adjustment is shown in Schedule ACC-29.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying costs are not necessary for the provision of safe and adequate utility service. Moreover, the lobbying activities of a regulated utility may be focused on policies and positions that enhance shareholders but may not benefit, and may even harm, ratepayers. Regulatory agencies generally disallow costs involved with lobbying, since most of these efforts are directed toward promoting the interests of the utilities' shareholders rather than its ratepayers. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate gas service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. Clearly, these costs should not be borne by ratepayers. For all these reasons, I recommend that lobbying activities be disallowed as shown in Schedule ACC-29.

N. <u>Depreciation Expense</u>

Q. Are you recommending any adjustment to the Company's depreciation expense claim?

A. Yes, I am recommending one adjustment. As discussed previously, I am recommending that the updated Distrigas allocation factor be used to allocate common corporate plant to KGS. Therefore, it is also necessary to utilize this updated allocation factor to allocate depreciation expense on this plant. At Schedule ACC-30, I have made an adjustment to allocate depreciation expense on common corporate plant using a Distrigas factor of 15.19%.

O. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-31. It is consistent (synchronized) with my recommended rate base, capital structure, and cost of capital recommendations. I am recommending a lower rate base than the rate base included in the Company's filing. My recommendation results in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under my recommendations. Therefore, my recommendations result in an interest synchronization adjustment that reflects a higher income tax burden for the Company, and a decrease to pro forma income at present rates.

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-32, I have used a composite income tax factor of 39.78%, which includes a state income tax rate of 7.35% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing. My revenue multiplier, which is shown in Schedule ACC-33, reflects these same income tax factors.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in this testimony?

A. My adjustments show that KGS has a revenue deficiency at present rates of $42,824,276, as summarized on Schedule ACC-1. My recommendations result in revenue requirement adjustments of $30,476,512 to the Company's requested revenue requirement increase of $73,300,788.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-34, I have quantified the revenue requirement impact of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

Q. Have you developed a pro forma income statement?

A. Yes, Schedule ACC-35 contains a pro forma income statement, showing utility operating income under several scenarios, including the Company's claimed operating income at present rates, my recommended operating income at present rates, and operating income under my proposed rate increase. My recommendations will result in an overall return on rate base of 8.03%.

VIII. PENSION AND EMPLOYEE BENEFITS RIDER

Q. Please describe the Company's proposed Pension and Employee Benefits Rider ("PEBR").

A. As described in the testimony of Ms. Hagerty, the Company is proposing to implement a PEBR. This rider would be an annual true-up mechanism, to true-up actual pension and OBEP costs with the amounts collected in rates. According to the proposed tariff, the PEBR would reflect the annual pension and OBEP costs, less the annual pension and PBEP costs embedded in base rates, plus or minus any over-recoveries or under-recoveries from the prior year.

Q. Are you opposed to a PEBR for KGS?

A. Yes, I am. KGS has lost sight of the foundation upon which the regulatory process was developed, i.e., regulation is intended to be a substitute for competition. Regulation is not intended to be a mechanism whereby a utility is guaranteed either recovery of its costs or a particular level of profit. The surcharge mechanism being proposed in this case is at odds with good regulatory practices. Under traditional regulation, a company is not guaranteed a profit, only a reasonable opportunity to earn a profit. This principle of regulation was designed to stimulate a utility company to act as it would if it were in a competitive industry. Regulation has classically been viewed as a substitute for competition. Any mechanism that diminishes the incentive for a utility company to actively manage its costs removes some of the ratepayer protections provided under traditional regulation.

While KGS argues that a true-up mechanism would be of benefit to both shareholders and ratepayers, it seems most likely that KGS is concerned with periods of increasing costs. I note that KGS did not propose a true-up mechanism until the annual pension accrual switched from a negative expense to a positive one. If the PEBR is adopted, customers of KGS that experience increased costs through a surcharge cannot simply go out and assess another third party for these additional costs. KGS should not be permitted to do so either.

Q. Does the PEBR represent single-issue ratemaking?

A. Yes, it does. This proposed true-up does not recognize other elements of costs that may decrease between rate cases, especially in the areas of productivity gains or cost of capital. The KCC has to make some major policy decisions in this case. Either it can retain the framework of the current regulatory process, which sets rates on a prospective basis and provides the opportunity for a company to earn its authorized rate of return, or it can continue down the slippery slope of reimbursement ratemaking.

Q. Is there already a significant amount of reimbursement ratemaking taking place in

Kansas?

A. Unfortunately, yes, there is. KGS has a COGR that ensures the Company dollar-for-dollar recovery of over 75% of its entire revenue requirement, a situation unheard of in the competitive market. Moreover, utility commissions have lost sight of the fact that utilities were successfully regulated for many, many years without the need for a COGR. In fact, some utilities in Kansas today still do not have a fuel cost recovery mechanism.

In addition, not only is the Company protected against price fluctuations for 75% of its revenue requirement, but it also has significant protection against the risk of fluctuating revenues through the WNC. In this case, the Company is requesting further protection from revenue risk by requesting an optional rate design that would result in high fixed charges, effectively guaranteeing a fixed revenue stream for KGS.

Moreover, recent legislation permits the Company to pass-through to ratepayers certain capital costs incurred between base rate case filings, while the Company already has a tariff to pass-through increases in ad valorem taxes and a large portion of its uncollectible costs.

If the PEBR is approved, there will be no limit as the types of expenses that the utilities will seek to recover through periodic true-up mechanisms. There is some uncertainty as to the costs associated with any expense element, which is the reason why utilities are awarded a return on equity that is higher than a risk-free rate. The fact that an element of cost is uncertain, or volatile, does not justify flowing the cost through to ratepayers. Management is responsible for planning and anticipating the cost of providing utility service, setting appropriate budgets, and obtaining rate relief through the regulatory process when necessary. Management of KGS should continue to be held accountable for these tasks.

I find the concept of a PEBR especially egregious to ratepayers when it is bundled with the other risk-mitigation mechanisms that are in place, or are being requested, at KGS. KGS is seeking both a guarantee of revenues and an opportunity to flow-through actual expenses, in addition to flowing-through the impact of certain construction projects completed between base rate cases. Such extensive revenue and cost recovery guarantees remove the regulatory incentives for utilities to provide utility services at the lowest possible cost. Removal of such incentives will only leave ratepayers funding bloated budgets with little prospect for management attention to cost containment.

Traditional regulation has been founded on the principle that the utility company has an opportunity to earn its rate of return. Returns have never been guaranteed because the production of utility services at the lowest possible cost requires that a company exert itself and work efficiently. Clearly, if revenues and major expense elements are all guaranteed recovery, then we have departed from our traditional ratemaking foundations. Moreover, competitive entities do not have any such guarantee of recovery. Since regulation is supposed to be a substitute for competition, regulated entities should not receive guaranteed cost recovery that is not available in the competitive marketplace.

Q. What is the implication for ratepayers if a PEBR is approved for KGS?

A. The true-up of this cost element not only removes any incentive to contain pension and post-retirement benefit costs, it reduces the incentive to control all other costs as well. Currently an increase in costs in any one area will stimulate cost cutting elsewhere as the Company strives to reach its return goals. This incentive will be lost if the PEBR is adopted.

Q. Has KGS taken steps to manage its pension and OBEP costs in the past?

A. Yes, it has. The Company has attempted to manage these costs by taking advantage of the prescription drug benefits offered by Medicare Part D to replace some of its own prescription drug benefits for retirees, and by excluding newly hired employees from post-retirement benefit coverage and participation in a defined benefit pension plan. Not only will these actions help to control costs, but they also make the costs for pensions and OPEBs much easier to predict from year-to-year.

Q. What happens under the Company's proposal if actual pension and OPEB costs are higher than the amounts being collected in rates, but the Company is still earning its authorized rate of return?

A. The Company's proposal has no return on equity test. Therefore, under KGS' proposal, the Company would still be allowed to add a surcharge to bills, regardless of the fact that it was earning its authorized rate of return. In this scenario, KGS would be allowed to increase its over-earnings via the surcharge mechanism on a dollar-for-dollar basis.

Q. Is there any limit regarding the amount of the surcharge that can be collected from

ratepayers in the absence of a base rate case?

A. No, there is not. The Company's tariff provides no limit on the amount or percentage of the surcharge.

Q. Does the Company's proposed PEBR apply to all customers?

A. The surcharge would apply to all sales and transportation customers, "except where service is subject to a separately negotiated discounted rate contract with a customer." Thus, contract customers would not necessarily be charged for these costs. This is another example of some customers receiving special treatment at the expense of residential and smaller commercial customers.

Q. Is the Company proposing to itemize the PEBR on its customer bills?

A. It doesn't appear so. According to the Company's proposed tariff, "[t]he surcharge calculated under this Rider shall become part of the total bill for gas service and need not be itemized separately on the customer's bill." Thus, while the Company wants its customers to accept 100% of the risk of pension and OBEP costs, the Company seems reluctant to tell customers exactly what they are paying for. The language of the proposed tariff appears to be an attempt to hide this surcharge from utility ratepayers.

Q. Please summarize your recommendation regarding the PEBR mechanism.

A. Ratemaking was established as a substitute for competition and designed so that utilities would have an opportunity, but not a guarantee, to earn the return on capital awarded in rates. If changes in operating expenses are flowed through directly to ratepayers between base rate cases, then the utility is approaching a guaranteed rate of return. Traditional regulation bases rates on normal conditions with the understanding that in some years a utility may over-earn its authorized return and in some years it may under-earn. The utility can file a rate case if it believes it will under-earn in future periods.

With a true-up mechanism, a utility has less incentive to be attentive to its business. If recovery of expenses is guaranteed between rate cases, then the management of a utility can grow inattentive to all aspects of its business, knowing that its bottom line is enormously cushioned through a guarantee of revenues. If its proposal is adopted, then KGS can be less concerned with the absolute price of employee benefits, since increases in costs will no longer impact the bottom line. When a utility has no incentive to contain costs, it may devote very little attention to providing utility service at the lowest possible cost. Ratepayers should pay for attentive management, not cosseted management that is immune from the consequences of its own decision-making. In addition, as discussed above, KGS' proposal does not include any decrease in its cost of capital even though its proposal greatly reduces the earnings risk of the Company. For all these reasons, I recommend that the Company's proposal to implement a PEBR be denied.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF CONNECTICUT)

COUNTY OF FAIRFIELD) ss:

Andrea C. Crane, being duly sworn upon her oath, deposes and states that she is a consultant for the Citizens' Utility Ratepayer Board, that she has read and is familiar with the foregoing testimony, and that the statements made herein are true to the best of her knowledge, information and belief.

Andrea C Crane

Andrea C. Crane

Subscribed and sworn before me this 25th day of September, 2006.

Notary Public Marjorie M. Levin

My Commission Expires: DECEMBER 31, 2008