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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

Docket No. G-04204A-08-0571

Arizona Corporation Commission
DOCKETED

NOTICE OF FILING
SURREBUTTAL TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Surrebuttal Testimony of Ralph C. Smith, Frank W. Radigan, and William A. Rigsby in the above-referenced matter.

RESPECTFULLY SUBMITTED this 29th day of July, 2009.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 29th day
of July, 2009 with:

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Phoenix, Arizona 85007

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BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

NON-CONFIDENTIAL SURREBUTTAL

TESTIMONY

[**CONFIDENTIAL INFORMATION HAS BEEN REDACTED**]

OF

RALPH C. SMITH

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2009

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571
SURREBUTTAL TESTIMONY OF RUCO WITNESS RALPH C. SMITH

My testimony addresses the following issues, and responds to the rebuttal testimony of UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- The determination of a Fair Value Rate of Return and its application to Fair Value Rate Base
- RUCO's recommended base revenue increase
- Adjusted Rate base
- Adjusted Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement
The Company had originally proposed a revenue requirement of a base rate increase of $9.480 million, or 18.53 percent. In its rebuttal, UNSG calculated a base rate increase that is approximately $146,000 higher than its original request, but indicated that it is not requesting a revenue requirement higher than proposed in its original Application. The Company's requested rate increase is significantly overstated.

UNSG overstated rate base and understated operating income. Additionally, the Company is requesting an excessive rate of return. The direct and rebuttal testimony of RUCO witness William Rigsby addresses RUCO's recommended return on equity and weighted cost of capital to be applied to OCRB.

The Determination of a Fair Value Rate of Return (FVROR) and its Application to FVRB
The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

That Court of Appeals decision provided some guidance for calculating the return on fair value rate base. For example, at pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision stated that: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted there fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

Attachment RCS-2, Schedule D, page 2, to my direct testimony showed the derivation of four FVROR calculations that were considered by RUCO, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

My surrebuttal testimony in the instant rate case elaborates upon RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above.

Adjusted Rate Base
The following adjustments to UNSG's proposed original cost rate base should be made:

- UNSG's proposed rate base increase for post test year plant should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.

- UNSG's proposed increase to rate base related to removing a portion of the cost-free, non-investor supplied capital in the form of Customer Advances should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.

- UNSG's attempt in its Rebuttal Testimony to increase the amount of Cash Working Capital in rate base by over $2 million for a post-test year change in the payment lag for purchased gas expense in retaliation to a Staff recommendation is one-sided and should be rejected for the reasons stated in my Surrebuttal Testimony.

- The adjustments to the specific components of Accumulated Deferred Income Taxes shown in Attachment RCS-2, Schedule B-2, filed with my Direct Testimony should be adopted for the reasons stated in my Direct and Surrebuttal Testimony. That adjustment decreases rate base by $423,669.

- If the Commission deems that the debit-balance ADIT of $170,414 related to the Accrued Vacation and Accrued Pension Liabilities should be included in rate base, then the corresponding balances in the Accrued Vacation and Accrued Pension Liability accounts, amounting to $441,483, should reduce rate base, to recognize this non-investor supplied cost-free capital, for a net reduction to rate base for these accrued liability items of $271,069.

Adjusted Net Operating Income
The following adjustments to UNSG's proposed revenues, expenses and net operating income should be made:

- UNSG's proposed revenue annualization, which attempts to decrease test year revenue, should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- The adjustments to Incentive Compensation Expense, Stock-Based Compensation, and Supplemental Executive Retirement Plan Expense recommended in my Direct Testimony should be made for the reasons stated in my Direct and Surrebuttal Testimony.
- UNSG's expense for the gas utility industry association, the American Gas Association, should be reduced by 40 percent, not the 4 percent proposed by UNSG, for the reasons stated in my Direct and Surrebuttal Testimony.
- A normalized allowance for UNSG's non-rate case Outside Legal Expense should be determined that takes into account changed circumstances and does not rely primarily on backward-looking historical information, as described in my Direct and Surrebuttal Testimony.
- UNSG's Fleet Fuel Expense for the test year was abnormally high, reflecting extreme high levels of gasoline prices, as described in my Direct and Surrebuttal Testimony. A normalized level should be used for ratemaking purposes, based on average usage and average prices for the period January 2006 through June 2009, as described in my Surrebuttal Testimony and shown on Attachment RCS-7, Schedule C-8 Revised.
- UNSG's proposed Rate Case Expense is excessive in comparison to the Commission allowed amounts in the last UNS Gas and the last UNS Electric rate cases. Rate Case Expense charged to UNSG's ratepayers should be limited to n annual allowance of $100,000 based on a total amount of $300,000 normalized over a three-year period as described in my Direct and Surrebuttal Testimony.
- UNSG's proposed increase to test year expense for a projected 2010 pay increase should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- A known and measureable postage rate increase occurred in May 2009. The amount of postage expense increase of approximately $22,000 corresponding with RUCO's recommended level of test year customers is shown on Attachment RCS-7, Schedule C-13.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Which UNS Gas rebuttal testimony do you address in your Surrebuttal Testimony?

A. I address certain adjustments and issues that were discussed in the Rebuttal Testimony of these UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses: Dallas Dukes, Bentley Erdwurm, Kentton Grant, David Hutchens, and Karen Kissinger. These issues include rate base adjustments, operating income adjustments and fair value rate of return.

Q. Have you prepared any exhibits to be filed with your Surrebuttal Testimony?

A. Yes. Attachments RCS-7 through RCS-10 contain the results of my analysis and copies of selected documents that are referenced in my surrebuttal testimony, respectively.

II. REVENUE REQUIREMENT

Q. What revenue increase has been requested by UNSG?

A. UNSG originally requested an increase in base rate revenues of $9.480 million, or approximately 6.1% percent, based on adjusted gas retail revenues at current rates of $51.158 million. UNSG witness Dukes states at page 3 of his rebuttal testimony that with the additional adjustments UNSG is now proposing, the Company's revenue requirement could increase by approximately $146,000; however, the Company is not requesting a revenue requirement higher than proposed in its Application. Mr. Dukes' rebuttal Exhibit DJD-1 shows the "UNSG Revised 7/8/09" requested increase in the gross revenue requirement as the same $9.480 million as in UNSG's original Application.

Q. Do you have any initial comments on UNSG's rebuttal filing?

A. Yes. In view of the poor economy and what some believe is the worst economic climate since the Great Depression, it is disappointing that UNSG continues to take a "business as usual" approach to this rate case, continuing to argue for a rate increase that is no lower than its initial filing, and continuing to include items such as Supplemental Executive Retirement Plan ("SERP") expense, incentive compensation, stock-based compensation, and budgeted 2010 pay increases that apparently have not been reduced in response to the economic conditions. Other utilities have responded differently under such circumstances and, as I will discuss in my testimony, have removed items such as SERP and incentive compensation, and have taken other steps such as freezing non-union and management salaries, removed previously disallowed expenses, and taken other steps in response to the financial crisis.

Q. Have you updated RUCO's recommended revenue requirement at this time?

A. Due to time frame allotted for responding to UNSG's rebuttal testimony I have not prepared a comprehensive update to RUCO's recommended revenue requirement at this time. However, it would be my intention to have such an update available at the time of my appearance at the hearing.

Fair Value Rate of Return

Q. What UNSG Rebuttal Testimony addresses the Fair Value Rate of Return?

A. The Fair Value Rate of Return ("FVROR") is addressed by UNSG witness Kentton Grant. Pages 33-35 of Mr. Grant's Rebuttal Testimony present the Company's criticisms of RUCO's proposed FVROR. Mr. Grant indicates that he found my description of the various FVROR calculation methodologies and related impacts on UNSG's revenue requirement to be helpful, but had the following criticisms:

(1) UNSG wants more than $38,000 of additional revenue under the FVROR versus an Original Cost Rate Base ("OCRB") based calculation.

(2) Lack of explanation for the alternatives.

(3) Failure to consider the financial impact of the FVROR recommendation.

(4) The RUCO FVROR calculations reflect what Mr. Grant believes to be an unreasonably low recommendation from RUCO witness William Rigsby.

Mr. Grant admits with reservations that UNSG is effectively requesting a Return on Equity ("ROE") of 12.58 percent on OCRB. His reservation is that he does not expect the Company to be able to earn the 12.58 percent; consequently, he disagrees that a 12.58 percent ROE would be an excessive rate of return.

I will address items 1-3 and the effective 12.58 percent ROE that is embedded in UNSG's revenue increase request. Mr. Rigsby provides surrebuttal testimony defending his recommended ROE.

Q. Please address the issue of how much additional revenue increase UNSG should receive under the FVROR over and above what the OCRB-based results show.

A. In my direct testimony, I recommended a FVROR-based result that would have given UNSG approximately $38,000 more than an OCRB-based result. In contrast, UNSG apparently seeks an additional $3.62 million "fair value difference" on top of its interpretation of Staff's recommendation and an additional $3.808 million "fair value difference" beyond RUCO's direct filing amount of approximately $734,000.[1] The amount of extra revenue increase, if any, using the FVROR, is a matter that is subject to the discretion and judgment of the Commission. In the current poor economic climate, a modest amount of additional revenue increase to the utility under the FVROR might be justified, but burdening ratepayers with an additional revenue increase of over $3.6 million for FVROR is not warranted.

Q. Please explain the FVROR alternatives that you considered and the basis for your recommendation.

A. Page 2 of Schedule A in Attachment RCS-2 that was filed with my direct testimony shows information concerning the potential impacts on UNSG's revenue deficiency in the current rate case that was considered by RUCO in developing the recommended FVROR recommendation. Similar to information presented by RUCO and Staff to the Commission in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, and in some other recent rate cases, I have also presented on Schedule A, page 2, in columns A through D various potential ways of determining a FVROR for UNSG, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25%

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[1] See UNSG's response to RUCO 11.13 which attempts to add a "fair value difference" of $3.620 million to UNSG's interpretation of Staff's filing and $3.808 million to RUCO's.

The details for each FVROR calculation are shown on Schedule D, page 2.

On Attachment RCS-2, on Schedule A, page 2, in column E, I also presented RUCO's ultimate recommendation of the FVROR and the resulting base rate revenue deficiency. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value. The four FVROR methods on Attachment RCS-2, Schedule A, as well as the OCRB-based result, have been presented for the Commission's informed consideration, given the analytical framework addressed in Decision No. 70441 and that has been under further development on a case-by-case basis.

The Commission's traditional calculation of return on fair value rate base calculation has been called into question by the Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution. Guidance for calculating the return on fair value rate base was provided in that Court of Appeals decision. First, the Court of Appeals specifically stated that the Commission was not bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City ... asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision stated as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The

Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is not bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB. At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted by the Commission in that case fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

In view of the Court of Appeals decision in the Chaparral City case and the subsequent guidance provided by the Commission in other recent decisions on the issue of FVROR, RUCO has appropriately adjusted the weighted cost of capital to derive a FVROR to apply to the utility's FVRB. My direct testimony presented RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above. Specifically, Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO. Mr. Smith's Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures. Schedule A, page 2, Column E shows RUCO's recommended FVROR and the resulting revenue deficiency. This FVROR recommendation was also applied to the FVRB on Schedule A, page 1, column D.

Additional explanations of my analysis were provided to UNSG in response to discovery, and are summarized here for ease of reference.

Calculation 1: This calculation is equivalent to the calculation method used by the Commission in setting the FVROR in Decision No. 70441 in the Chaparral City remand proceeding. However, it is clear that the Commission left itself with flexibility to consider the results of various calculations and in fact considered the results of various methods in that case and selected one that made sense in the context of that case. The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted in that particular proceeding fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process. Based on the result shown on Schedule A, page 2, the Calculation 1 method would provide UNSG with an unjustified windfall of over \$3.8 million and thus was evaluated as being "way too high." Specifically, in the context of the current UNSG rate case, the Calculation 1 method produces a rate increase that is way too high and is therefore not being recommended by RUCO.

Calculation 2: This calculation reflects one of the methods discussed in the Chaparral City remand case by RUCO's witness in that case, Ben Johnson. This method is based on an analysis that there is an inflation component in both the cost of equity and the cost of debt, i.e., in the WACC. Dr. Johnson's testimony in that case contained additional discussion of the reasons for this method. Decision No. 70441 indicates that the Commission has discretion in determining the FVROR in each case. Additional testimony from RUCO witness William Rigsby in the current UNSG rate case provides further support for the fact that there is an inflation component to the cost of debt. The result of Calculation 2 in RUCO's filing would have produced a rate decrease, which did not seem to be appropriate in the context of the current UNSG rate case, given the OCRB-based revenue requirement and the results of the other FVROR based methods.

Calculation 3: This could be viewed as mathematically equivalent to a zero weighting of FVRB in the determination of revenue requirement. In other words, applying a zero cost of capital to the FV rate base increment that is not financed with any debt or equity capital that has been recorded on the utility's books could be formulated in the context of an algebraic formulation that produces a required net operating income amount presenting the same result as applying the WACC to OCRB. The reason for differences between the required net operating income result under these two approaches is attributable to rounding This method is nevertheless appropriate for Commission consideration because it is logically supported by appropriate economic, financial and ratemaking principles, which include that the FVRB increment is not financed with any debt or equity capital on the utility's books, and thus could be viewed for ratemaking purposes as being supported entirely by zero-cost capital. The economic and financial logic supporting the application of a zero cost rate to the FV Increment of the capital structure includes the following: the weighted average cost of capital is conceptually suited to apply to an OCRB; the OCRB is based largely on amounts recorded on the utility's books; the OCRB is financed with debt and equity that are recorded on the utility's books; the difference between the FVRB and the OCRB has not been financed by any identifiable debt or equity capital on the utility's books; rate base elements that are supported by zero cost capital typically do not earn a return since there is no investment by the utility and allowing a return could thus produce windfall profits. In other words, as shown on Attachment RCS-2, Schedule D, filed with Mr. Smith's direct testimony, the weighted average cost of capital developed for the application to the OCRB under Calculation 3 is appropriately adjusted for application to a FVRB by recalculating the capital structure ratios and assigning a zero financing cost to the FV Increment, which is not supported by debt and equity on the utility's books. Additional explanation of the support for this method, from a financial perspective, has been presented in the direct and surrebuttal testimony of David Parcell, who presented testimony on behalf of the Commission Staff in the Chaparral City remand case, in Docket No. W-02113A-04-0616. The result of Calculation 3 would have produced a rate increase that was slightly below the OCRB-revenue requirement in RUCO's filing. This result did not seem to be appropriate in the context of the current UNSG rate case, given the OCRB-based revenue requirement and the results of the other FVROR based methods.

Calculation 4: This calculation is based on Staff recommendations that have been developed in a series of rate cases since the Court of Appeals Decision in the Chaparral City rate case in which the FVROR was an issue. It applied a rate of 1.25 percent to the FVRB increment. The 1.25% is the midpoint of a range from zero to 2.5 percent.[2] The low end of the range, zero, is based on the fact that the FVRB increment is not financed by any debt or equity capital on the utility's books. An estimate of inflation

[2] $(0 + 2.5) / 2 = 1.25$.

was developed for purposes of RUCO's use in the current UNSG case by RUCO witness William Rigsby as shown on his Schedule WAR – 1, page 4. As shown there, 2.5% is the average inflation rate from the data set used by Mr. Rigsby for 2001-2008, and this could be viewed as a very conservative estimate of inflation embedded in the risk-free interest rate, since the indicated inflation component for more recent years in the data series was higher: e.g., 2008 was 3.66 percent. The estimate of the real risk-free rate of return was supplied by RUCO witness William Rigsby and is based on his estimate of the risk free rate of return less inflation. Based on the result shown on Attachment RCS-2, Schedule A, page 2, the Calculation 4 method would provide UNSG with an unjustified windfall of almost $1.49 million and thus was evaluated as being "too high."

In summary, as explained in detail above, the criteria used was informed judgment and a detailed attempt to apply the guidance articulated in the Court of Appeals remand decision and in Commission Decision No. 70441. The determination of FVROR is at best an estimation and not an exact science. The goal is to provide the Company with an opportunity to earn a reasonable rate of return, not to provide the Company with an excessive rate increase or a windfall. Based on my direct knowledge of how the FVROR has been under further development on a case-by-case basis in some of the other cases that have attempted to address this issue subsequent to the Court of Appeals remand decision, I believe that RUCO's presentation in the instant UNSG rate case, and the resultant recommendation fully complies with such guidance and results in a reasonable and fair rate of return when all relevant and appropriate factors are considered.

Q. Please explain how UNSG is effectively requesting an ROE of 12.58 percent.

A. On its Schedule D-1, UNSG purported to be requesting a return on equity ("ROE") of 11.0 percent, and an overall rate of return of 8.75 percent. However, on its Schedule A-1, line 7, UNSG has applied an overall rate of return of 9.54 percent to its proposed OCRB. On

Schedule D, I have shown a calculation based on the capital structure UNSG used for developing its recommended rate of return of 9.54 percent on OCRB. This calculation shows that the equivalent return on equity ("ROE") implicit in UNSG's request for 9.54 percent on OCRB is an ROE of 12.58 percent, as summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

Q. **Would an ROE of 12.58 percent be excessive?**

A. Yes. It would substantially exceed the ROEs for OCRB recommended by the witnesses for RUCO and Staff in this case.

Q. **Mr. Grant also criticizes RUCO for alleged failure to consider the financial impact of the FVROR recommendation. Please respond.**

A. Mr. Rigsby addresses this in his Surrebuttal Testimony. In addition, I address concerns about Mr. Grant's attempt to use questionable forecasts that do not reflect typical ratemaking adjustments as a basis for evaluating the recommendations made by Staff and RUCO in this case. Mr. Grant appears to be relying on financial forecasts on page 24 of his Rebuttal Testimony, which have revised forecasts originally presented on page 27 of his Direct Testimony. I would caution against placing much reliance upon forecasts as the basis for ratemaking treatments because forecasts are subject to change and can be inaccurate.[3] Additionally, the forecasts presented by Mr. Grant should not replace the Commission's traditional test year analysis, with unaudited future projections. Moreover,

[3] For example, Mr. Grant's rebuttal, at page 15, in the prior UNSG rate case stated that in 2003, the Company could not foresee the amount of capital investment needed to serve customer growth and system improvement needs, and that "it was difficult to predict the future impact of regulatory lag on UNS Gas."

Mr. Grant's projections do not reflect ratemaking adjustments that would typically be required by the Commission.[4] Without reflecting the impact of the specific adjustments which cause that difference (i.e., without also reflecting the reasons for the difference) is questionable and unlikely to produce reliable forecasts that are meaningful and relevant for ratemaking purposes. In states that utilize future test years, where projections are made beyond the historical period, adjustments are typically made to all of the components of the ratemaking formula which impact the level of revenues; however, Mr. Grant's projections apparently do not incorporate this. In jurisdictions that utilize future test years, when adjustments are made for disallowed expenses, the disallowed expenses are removed from the future test year. To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons do not appear to reflect the adjustments to rate base or expenses that contribute to Staff or RUCO recommending a different level of revenue increase than has been requested by the Company.

III. RATE BASE

ADJUSTMENTS TO ORIGNAL COST RATE BASE

Q. Please discuss RUCO's adjustments to UNSG's proposed original cost rate base.

A. RUCO has made five adjustments to UNSG's proposed original cost rate base. These have been designated as RUCO Adjustments B-1 through B-6. Each adjustment is discussed below.

B-1 Post Test Year Plant

Q. What has UNSG proposed for Post-Test Year Plant?

[4] See, e.g., UNGS' response to RUCO 11.38.

A. UNS Gas has proposed to include $1.528 million of Post Test Year Non-Revenue Producing Plant in Service (i.e., Construction Work in Progress ("CWIP")) in rate base. RUCO adjustment B-1 removed that amount from rate base.

Q. Please discuss UNS Gas' reasons for disagreeing with your recommendation to remove such post test year plant in rate base.

A. As described in the Rebuttal Testimony of UNS Gas witness Dallas Dukes at pages 4-5:

(1) The post test year plant is not CWIP.

(2) Previous Commission decisions have included non-revenue producing post-test year plant in rate base.

(3) Mr. Dukes believes that the reason the Commission rejected UNSG's request for post test year plant in its last rate case (Decision No. 70011) was that UNSG made no attempt to segregate revenue-producing plant from non-revenue producing plant, and UNSG has attempted to address this in the current case.

Q. IS UNSG's request for post test year plant based on CWIP balances at the end of the test year?

A. Yes. It is a subset of CWIP.[5] As such, it suffers from all of the concerns associated with the inclusion of CWIP in rate base, including:

1) Inclusion of CWIP or post test year plant in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

[5] See, e.g., UNSG's response to RUCO 11.28d: All "post test year plant" that UNSG is requesting in rate base was in CWIP as of the end of the test year.

2) The CWIP was not in service at the end of the test year. As of June 30, 2008, the projects were not serving customers.

3) The Company has not demonstrated that the portion of its June 30, 2008 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for plant which can be related to serving customer growth, and/or can reduce expenses for maintenance.

4) Revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports or the expense reductions such plant additions could enable, would be imbalanced.

Q. Is inclusion of post test year plant in rate base up to the discretion of the Commission?

A. Yes, it is. RUCO's understanding is, in specific instances, the Commission has allowed some water utilities to include post test year plant in rate base, but the Commission's general practice, particularly for energy utilities, such as UNSG, has been to not allow post test year plant or CWIP to be included in rate base. As such, the Commission denied the Company's request for CWIP in rate base in its last rate case.[6]

Q. Does RUCO agree with the proposal of UNS Gas to include post test year plant in rate base in the current case?

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[6] Decision No. 70011, Docket No. G-04204A-06-0463

A. No. In general, RUCO does not favor inclusion of post test year plant in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment.

Q. What criteria did UNSG use to select the portion of its June 30, 2008 CWIP balance for its post test year plant in rate base claim in the current case?

A. As described in UNSG's response to RUCO 11.30b and c, certain UNSG and affiliate personnel were given verbal instructions to identify "non-additional" revenue producing plant that was not being installed for the purpose of meeting customer growth and investments that would have been made whether UNSG added additional customers or not. Concerning mains and services, UNSG attempted to identify replacements whose primary purposes were to serve existing customers and would have been replaced regardless of customer additions.

As such, the criteria used by UNSG to select the June 30, 2008 CWIP balance for its post test year plant in rate base claim in the current case was a bit loose and apparently did not consider whether the project would be expense reducing or whether it would help facilitate service to customers added after the test year.

Q. Why is it important that the plant be both non-revenue producing and non-expense reducing?

A. If post test year plant is revenue producing or supports the addition of customers beyond the end of the test year, or if it enables the reduction of expenses, such as the replacement of aging mains and services, or the replacement of older transportation of equipment could do, then a mis-match would result. Rates would be increased for the inclusion of such plant in rate base; however, revenue would not be extended for new customers and expense reductions would not be reflected. UNSG's response to data request RUCO 11.18 identifies various post test year expense reductions, including reduced overtime, reduced vehicle maintenance, reduced vehicle depreciation, etc., none of which have been reflected. It is imbalanced to include in rate base plant that was not in service during the test year and to ignore expense reductions. Rather than attempt to make pro forma adjustments for the post test year expense reductions, the Company's post test year plant adjustment should be rejected.

Q. Please elaborate on how including post test year plant in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. Post test year plant, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. In Arizona, the ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. Arizona's ratemaking process therefore excludes such plant from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is June 30, 2008, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such post test year plant should be excluded from rate base.

Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test year. The inclusion of plant in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, such plant should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule[7]. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding such plant from rate base. It is not appropriate to include the plant in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year ended June 30, 2008.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on

[7] RUCO is aware of only one instance in which the Commission has allowed CWIP in rate base for an energy utility. That occurred in the early 1980s when the Commission considered the costs associated with the Palo Verde Nuclear Plant. Because the up-front costs were so great, the Commission allowed CWIP in rate base in order for the plant to be built.

the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Did the Commission address this issue in UNS Gas' last rate case?

A. Yes. The Commission's decision in Decision No. 70011 addressed the issue of post-test year plant at pages 7-8, and reached the following conclusion:

> We agree with Staff that post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP. Although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur. For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (i.e., not funded by CIAC or AIAC)" (Id. at 5). In the instant case, however, the Company's request appears to be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. The entirety of UNS's argument consists of two questions in Mr. Grant's direct testimony, which essentially provided that: the Commission has approved post-test-year plant in some prior cases, UNS is experiencing a high customer growth rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-27 at 28-29). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (i.e., whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Q. Could the replacement of old mains and services reduce maintenance cost?

A. Yes.[8]

[8] See, e.g., UNSG's response to RUCO 11.28a

Q. Could the additional transportation equipment help serve customer growth and/or reduce maintenance costs?

A. Yes.[9]

Q. UNS Gas witness Dukes cites to five decisions on page 4, line 18, of his Rebuttal Testimony as the support UNSG is relying on for Commission decisions that have included post-test year plant in rate base. Are any of those decisions for energy utilities?

A. No, they all pertain to water utilities, as admitted by UNSG in response to RUCO 11.28e. UNSG is not a water utility, and has not cited any decisions allowing post test year plant for an energy utility in its Rebuttal Testimony, as admitted in response to RUCO 11.28f and g, respectively. Moreover, the Commission has denied the inclusion of post-test year plant in rate base in other decisions, including the decisions in UNSG's and its affiliate, UNS Electric's last rate cases.

Q. Is there any other deficiency related to UNSG's proposed treatment of post-test year plant?

A. Yes. UNSG has apparently failed to reflect a lower amount of rate base related to the application of 2008 bonus tax depreciation on the post-test year plant. Qualifying plant additions in 2008 (and 2009) are eligible for 50 percent bonus tax depreciation. UNSG's CONFIDENTIAL response to RUCO 11.39(e) claims that [**BEGIN CONFIDENTIAL**]

[9] See, e.g., UNSG's response to RUCO 11.28b and c.

[**END CONFIDENTIAL**] However, this response by UNSG fails to recognize that the Company did include, as a pro forma adjustment, additional depreciation related to the post test year plant. Consequently, the Company's proposed treatment of post test year plant fails the matching principle by failing to reflect the increased ADIT related to such post test year plant, which would include the impact of bonus tax depreciation, and thus overstates rate base. UNSG's CONFIDENTIAL response to RUCO 11.39 contains some additional information from which a rate base adjustment for ADIT related to the post test year plant could presumably be derived. Such an adjustment is not necessary as long as the Commission rejects UNSG's proposal to include post test year plant in rate base. However, if that adjustment were to be allowed, a related adjustment to increase ADIT and decrease rate base, related to the pro forma book depreciation and the bonus tax depreciation on such post test year plant, would need to be made.

Q. Please summarize your recommendation concerning post test year plant.

A. UNS Gas's proposal to treat a portion of its CWIP at the end of the test year as if it were plant in service should be rejected for the reasons stated in my direct testimony and above.

B-2 Customer Advances for Construction

Q. What is the dispute concerning Customer Advances?

A. UNSG seeks to increase rate base by $589,152 by removing a portion of its actual June 30, 2008 Customer Advances. Customer Advances are typically reflected as a reduction to utility rate base. Staff and RUCO have recommended reflecting the full end-of-test-year balance for Customer Advances as the reduction to rate base.

Q. Why has UNSG sought to remove $589,152 from Customer Advances?

A. Mr. Dukes' Rebuttal Testimony at page 6-7 claims that this amount of Customer Advances relates to projects that are not in rate base as of the end of the test year.

Q. Was a similar claim made by UNSG in its last rate case?

A. Yes. As one of UNSG's supporting arguments for its attempt to include CWIP in rate base, UNSG had also attempted to have a portion of Customer Advances excluded from the determination of rate base, using similar arguments from the prior case.

Q. Did the Commission make that UNSG-proposed adjustment in UNSG's last rate case?

A. No. In UNSG's last rate case, the Commission appropriately deducted the full amount of Customer Advances from rate base. This issue is addressed in Decision No. 70011 at pages 8-10, and the Commission reached the following conclusion:

> We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.
>
> As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Q. Does UNSG have the use of the money provided for in Customer Advances?

A. Yes. UNSG has the use of such money, which is fungible. UNSG does not hold the Customer Advance money in an escrow account. It represents non-investor supplied capital that should be deducted from rate base.

Q. Please respond to Mr. Dukes' rebuttal at pages 6-7?

A. Mr. Dukes first agrees that Customer Advances are non-investor supplied capital, and he agrees that they should be deducted from rate base so that the Company does not earn a return on investments it does not make. However, Mr. Dukes' proposal (1) does not deduct the full amount of Customer Advances from rate base, and (2) UNSG does not deduct Customer Advances in its calculation of Allowance for Funds Used During Construction ("AFUDC") either, thus, if Mr. Dukes' recommendation were to be adopted, UNSG would earn a return on investments supported by non-investor supplied capital. Mr. Dukes has ignored the fact that UNSG records AFUDC on construction projects. The AFUDC is calculated on the CWIP balance, without any reduction for Customer Advances. That is, UNSG does not reduce CWIP by Customers Advances prior to calculating AFUDC. The AFUDC represents the return to the Company during the construction period. If the Customer Advances related to CWIP are not deducted in full from rate base, this creates an inappropriate situation where the utility would earn a return on the non-investor supplied capital because the Customer Advances related to CWIP have not been reflected as either reduction to rate base or as a reduction to CWIP for purposes of the AFUDC calculation. Since the Customer Advances do not reduce the CWIP balance upon which AFUDC is calculated, they must be reflected in full as a reduction to rate base. To do otherwise would fail to appropriately recognize the Customer Advances as a source of non-investor supplied capital.

Q. Do you agree with UNSG's claim that some Customer Advances should be excluded in the determination of rate base?

A. No. Because Customer Advances represent non-investor supplied capital, they should be reflected as a deduction to rate base. Additionally, research conducted in the context of UNSG's last rate case did not reveal any instance in which CWIP for a major utility was excluded from rate base and customer advances were not also reflected as a deduction to rate base. Additionally, the Commission's rules at A.A.C. R14-2-103, Appendix B, Schedule B-1, require companies to reflect Advances as a deduction from rate base. Consequently, the rate base deduction for Customer Advances should reflect the full end-of-test year amount. For the reasons described in my Direct Testimony and above, the adjustment proposed by UNSG should be rejected. Customer Advances proposed by UNSG should be increased by $589,152 and rate base reduced by this amount.

B-4 Cash Working Capital

Q. Have you reviewed the Company's revised request for a cash working capital allowance?

A. Yes. The Company had originally proposed a cash working capital allowance of approximately $1,568, i.e., under $1,600. Now, in rebuttal, UNSG is seeking a cash working capital allowance of over $2.18 million. It appears that in response to an adjustment by Staff witness Fish that attempts to increase the Company's purchased gas payment lag, UNSG is now proposing a substantially shortened lag.

Q. Do you agree with the Staff's proposed gas purchase payment lag?

A. No. The gas purchase payment lag proposed by Staff witness Fish is inadequately supported, and for that reason should not be adopted.

Q. What support in its Rebuttal Testimony did UNSG provide for the drastically different new gas purchase payment lag and much higher cash working capital allowance?

A. Not much. The Rebuttal Testimony of UNSG witness Dukes on this major change in the Company's working capital calculation consists of one paragraph at page 2 identifying the Company's new, much higher cash working capital request, and a rather vague discussion at page 8.

Q. Did UNSG provide additional information in response to RUCO discovery?

A. Yes. UNSG provided its rebuttal workpapers and Excel files in response to RUCO 10.1. UNSG provided some additional information in response to RUCO 11.33.

Q. Should the drastically higher new cash working capital allowance proposed by UNSG for the first time in its rebuttal testimony be adopted?

A. No, it should not be adopted, for several reasons including the following:

(1) The purchased gas payment lag for the test year is documented at Company workpapers UNSG 0571/01980 through 02063 and shows a weighted lag of 27.89 days.[10]

(2) The purchased gas payment lag payment lag of 27.89 days UNSG used in the current case is fairly consistent with the lag used by UNSG in its prior rate case of 30.97 days for this item.[11]

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[10] A copy of those UNSG workpapers was provided in on CD in response to Staff data request JMK 1.1. Because of the volume, those UNSG workpapers are not included.

[11] See, e.g., UNSG's response to Staff data request TF 6.27.

(3) UNSG's proposed change would reach outside of the test year for one item that increases the revenue requirement without considering other offsetting items.

(4) The coverage of the post-test year change in gas procurement responsibility from BP Energy to the affiliate, TEP, which was described in Staff's prudence review of UNSG's gas procurement, indicated that this should produce a benefit to UNSG's ratepayers, not an additional revenue requirement burden.

(5) UNSG has not demonstrated that a change in the payment terms is permanent.

Q. Please explain how the purchased gas payment lag for the test year is documented at Company workpapers UNSG 05741 / 01980 through 02063 and shows a weighted lag of 27.89 days.

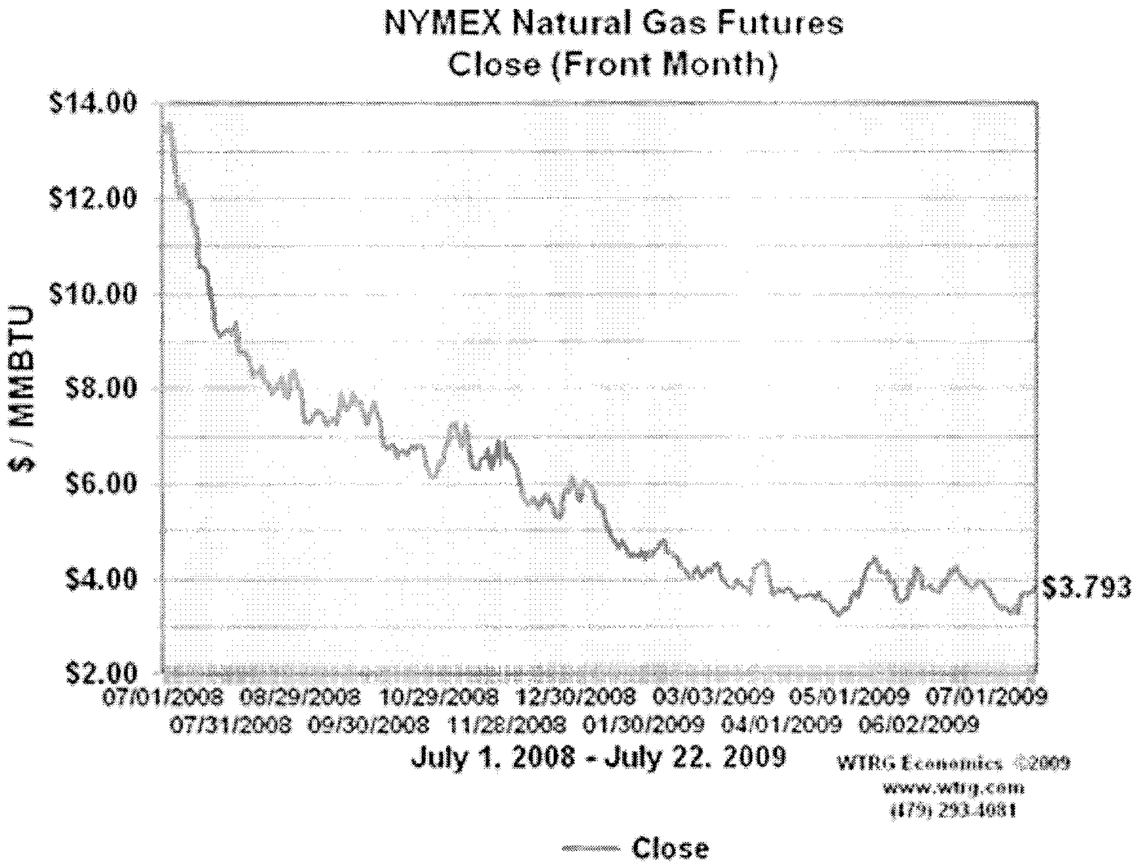
A. That documentation shows in detail how the gas purchases for the test year produced the weighted lag of 27.89 days, based on dollar day weighting of purchases from BP Energy Company, El Paso Natural Gas, and Transwestern Pipeline Company.[12]

Q. Please explain how UNSG's proposed change would reach outside of the test year for one item that increases the revenue requirement without considering other offsetting items.

A. The test year consists of the 12 month period ended June 30, 2008. UNSG's revised purchase gas payment lag calculation, which was provided in response to RUCO 10.1 is based on July 2008 through May 2009 information for gas purchases from BP Energy, but retains the Company's originally calculated lags for El Paso and Transwestern. Only by going outside of the test year and into subsequent months has UNSG derived its new proposed and much shorter gas purchase payment lag. However, when applying the gas

[12] Because of the volume, the UNSG workpapers for the purchased gas payment lag are not being included in Attachment RCS-8; however, a one-page summary, from UNSG's response to data request RUCO 10.1, which shows Mr. Dukes' supporting workpaper that summarizes the derivation of the 27.89 day lag contained in UNSG's lead lag study, and the much shorter lag that UNSG has proposed in its Rebuttal Testimony, is included in Attachment RCS-7.

purchase lag in its lead-lag study, UNSG failed to apply it to the same $87,528,793 purchased gas expense amount from UNSG's original filing[13], and thus failed to capture and reflect declines in the cost of natural gas that have occurred subsequent to the test year. As shown in the following graph, which shows NYMEX future prices, natural gas costs have declined considerably subsequent to the test year:



[13] See UNSG Schedule B-5, page 3, line 7, column B.

By applying a new much shorter payment lag based on post test year-derived to the same amount of test year natural gas purchase expense in its original filing, UNSG has distorted the impact upon rate base in a one sided manner. UNSG's calculation would overstate the amount of cash working capital and revenue requirement.

Q. The NYMEX graph shows the decline in natural gas prices generally since the test year. Do you have specific information on post test year natural gas cost decreases that UNSG has failed to reflect?

A. Yes. The following table summarizes the natural gas purchases from BP that UNS Gas used (1) to derive its originally proposed test year payment lag and (2) to derive its significantly shortened payment lag. Because UNSG only used an 11-month period (July 2008 through May 2009) for its new proposed lag, the comparison only uses the comparable 11 months from the test year (i.e., July 2007 through May 2008):

Gas Purchase Payments to BP Energy	
59,683,901	July 2008 - May 2009
102,031,354	July 2007 - May 2008
(42,347,453)	Dollar Change
-42%	Percent Change

Source: RUCO 10.1 UNSG Purchase Gas Lag Days Rebuttal Excel file

As shown, the gas purchased from BP Energy have decreased by over $42.3 million, or by approximately 42 percent, based on the comparison of these two 11-month periods.

Q. Are there other post test year cost decreases that UNSG has failed to reflect?

A. Yes. There are a number of post test year cost decreases that UNSG has failed to reflect.

UNSG's response to RUCO 11.18 identifies savings in labor costs, meter reading, repairs and maintenance, vehicle maintenance, training and travel, communications and vehicle depreciation, which have not been reflected in the test year.

UNSG's response to RUCO 11.19 identifies an annual cost reduction related to using Walmart for customer payments of approximately $42,000.

UNSG's response to RUCO 11.20 identifies annual cost reductions from UNS Gas lobby office closings.

Q. How was the post-test year change in responsibility for gas procurement addressed in Staff's prudence review of UNSG's purchasing?

A. The testimony of Staff witness Rita Beale addressed a prudence review of UNSG's gas procurement operations and apparently focused on the period from January 2006 to June 2008, with some discussion of post-test year changes. Page 6 of Ms. Beale's testimony, for example, mentions that: "Contractually, gas procurement services ended with BP Energy Services on August 31, 2008 and began in TEP Wholesale Department starting September 1, 2008. As a result, BP's role changed to become one of a number of suppliers canvassed by UNS Gas to purchase gas."

Q. Wasn't the post test year transfer of gas procurement from BP Energy to UNSG's affiliate, TEP, expected to provide net <u>benefits</u> to UNSG ratepayers?

A. I thought so, based on the Direct Testimony of Staff witness Beale at pages 5-8, including this testimony at page 8:

> Q. Are there any other benefits that derive to UNS Gas ratepayers?
> A. UNS Gas has gained the benefit of first hand price discovery by virtue of TEP's direct participation in the market, whereas formerly BP was the entity facing the market. UNS Gas also retains the choice of changing AMA partners should market conditions warrant, both of which should help lower the gas supply and transport costs over the long term. There should be increased accountability for decision-making during severe and critical pipeline operating conditions. Sharing of the cost of gas procurement operations with two UniSource entities, Tucson Electric and UNS Electric is another benefit. UNS Gas's load is winter peaking versus summer peaking for the electric companies, so they are a natural complement. Other benefits are related to credit risk management which is essential to lock-in purchases of gas in the forward markets. UNS Gas's

> counterparty credit risk is theoretically more diversified by using multiple gas suppliers, and UNS Gas should be able to access a greater amount of credit by using multiple suppliers.

Q. Is the substantial increase in its request for cash working capital consistent with the post test year changes in gas procurement functions producing a net benefit to ratepayers?

A. No. The attempt in UNSG's rebuttal testimony to reflect only one post-test year change in its gas procurement, to significantly increase its cash working capital allowance, without considering other offsetting changes and benefits to ratepayers produced by post-test year changes in the gas procurement function, and/or the post test year declines in the cost of natural is thus one-sided and inappropriate.

Q. Has UNSG demonstrated that a change in the gas purchased payment terms is permanent?

A. No. Mr. Dukes' Rebuttal Testimony at page 8 mentions that the payment terms were adjusted because of credit limitations. Moreover, UNSG is a winter-peaking gas distribution company, so its exposure to gas suppliers is highest during the winter months of November through April. A temporary adjustment in payment terms to twice-per-month payments to BP Energy had occurred in the previous winter (December 2007 – January 2008) which then reverted back to a monthly payment and that is reflected in the test year gas purchase payment lag. After exceeding its credit limit with BP Energy, UNSG agreed to more frequent payments (twice monthly) and a standby letter of credit so UNSG could continue to enter into new transactions with BP Energy. A number of alternatives are available in such a situation. As described in the response to RUCO 11.27k:

> UNS Gas could make more frequent payments of amounts owed for gas supplied, could provide a standby letter of credit from a financial institution, or could curtail

> doing new business with the supplier, or a combination of these actions. The decision to provide a letter of credit vs. make prepayments depends on several factors including available credit under its revolving credit facility to issue letters of credit, the cost of issuing letters of credit, the amount of available cash on hand, and the interest rate that could be earned on the investment of excess cash.

UNSG has presented no analysis of the impact of each of these factors from the ratepayers' perspective and has not demonstrated that agreeing to more frequent payment terms was the least cost solution from ratepayers' perspective. Some of the other alternatives, such as incurring the cost of a letter of credit in a non-test year period, may not have had any impact on test year costs or ratepayers. Finally, as stated in response to RUCO 11.27(o): "As long as the vendor's total exposure to UNS Gas is within the credit limit established for UNS Gas, UNS Gas may pay for purchased gas on a monthly basis." Based on all of this, UNSG has failed to establish that payments every two weeks for the purchase of natural gas is permanent, or even is an impact that UNSG's ratepayers should be held responsible for.

Q. Please summarize your recommendation of the purchase gas payment lag that should be applied for purposes of computing cash working capital in the current UNSG rate case, which uses a test year ended June 30, 2008.

A. The payment lag of 27.89 days that is documented in the Company's workpapers should be used. UNSG's attempt to substantially revise this lag in rebuttal and increase costs to ratepayers based on an isolated impact of a post-test year change should be rejected for the reasons described above.

Q. Are you recommending any revisions to UNSG's cash working capital request?

A. Yes. The Company's attempt to revise the payment lag for gas purchases in a one-sided manner based on a post test year change should be rejected. Additionally, prior to testifying at the hearings, I would propose to update UNSG's cash working capital allowance to reflect the impact of RUCO's adjustments to operating expenses and revenue based taxes, and to synchronize the calculation of cash working capital with RUCO's recommended revenue increase.[14] I have reserved Schedule B-4 for a cash working capital update.

B-6 Accumulated Deferred Income Taxes

Q. What adjustment had you proposed to Accumulated Deferred Income Taxes ("ADIT") that were included in rate base by UNSG for Accounts 190 and 283?

A. In my direct testimony, as shown on Attachment RCS-2, Schedule B-6, I recommended that the following items reflected in Accounts 190 and 283 are removed:

- Dividend Equivalents
- Restricted Stock
- Restricted Stock - Directors
- Stock Options
- Vacation
- Pension

Each of these items has no corresponding liability that is offsetting rate base. The removal of these items decreases rate base by $423,669.

Q. Has UNSG objected to the removal of any of these ADIT items in its Rebuttal Testimony?

A. Yes. UNSG witness Kissinger opposes the adjustment for ADIT related to accrued pension and vacation liabilities because (1) such items were not removed in the prior

[14] Such synchronization has not yet been reflected at this time, but would be incorporated in a subsequent filing or in RUCO's brief.

UNSG rate case, and (2) such items "are calculated on an accrual basis and are a component of operating expense reflected in rates."[15]

Q. Does Ms. Kissinger admit that ADIT related to stock-based compensation was not allowed by the Commission as a component of rate base in UNSG's last rate case?

A. Yes, she indicates that the ADIT was disallowed because the underlying expense was disallowed, and in those circumstances the adjustment to ADIT is appropriate.[16]

Q. Have you recommended that the ADIT related to stock-based compensation be removed?

A. Yes.

Q. At page 3, Ms. Kissinger claims that removal of ADIT related to accrued pension and vacation liabilities "is another example of RUCO challenging accepted Commission-approved methods." Please respond.

A. Neither RUCO nor UNSG could identify where these items had been addressed in the prior cases cited in Ms. Kissinger's Rebuttal Testimony on page 3. UNSG's response to RUCO 11.25 states that:

> In the cases referenced on page 3 of the Rebuttal Testimony, there were no challenges of the inclusion of these items in rate base. Therefore, there was no need for the Commission to explicitly discuss these items in Decisions.

UNSG's response to RUCO 11.24 admits that:

> The Commission's method in addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide the case based on the facts and evidence in that case.

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[15] See, e.g., Kissinger rebuttal, page 3.
[16] See, Kissinger rebuttal, pages 3-4.

> The Commission's method is to consider the facts and evidence in light of its past practices and treatment of specific items in other cases with the same facts and evidence. By so doing, the Commission provides consistency of treatment among the ratepayers of Arizona.

Q. Do you agree with Ms. Kissinger's analysis of why an ADIT item should or shouldn't be included in rate base?

A. I agree that if an item is disallowed for ratemaking purpose, the related ADIT should also be removed. However, Ms. Kissinger's analysis would only focus upon ADIT in terms of operating expenses, and fails to recognize that there is a direct relationship between ADIT balances and other asset or liability accounts on a company's balance sheet. For example, as listed in UNSG's response to RUCO 11.21, the Company had balances of accrued vacation liability and accrued pension liability on its books at beginning and end of the test year, as listed there. The balances as of the June 30, 2008, the end of the test year are: $438,776 for the Accrued Vacation Liability and $1,732,676 for the Accrued Pension Liability. As such, these balances represent a source of non-investor supplied funds to the Company. Moreover, there is a direct relationship between the accrued liability amounts and the related amounts of ADIT for these items.

Q. How can non-investor supplied cost-free capital be reflected in the development of a utility's rate base?

A. Non-investor supplied cost-free capital, such as these accrued liabilities, could be reflected in the development of a utility's rate base in various ways, including (1) by adjusting the payment lags that are applied to the cash expenses in a lead-lag study or (2), by deducting the test year balances of the non-investor supplied capital from rate base.

Q. Did UNSG address the accrued vacation and accrued pension liability in its lead-lag study?

A. According to the response to RUCO 11.26(a), UNSG did not make any specific adjustments in its lead-lag study for Accrued Vacation Liability. UNSG's response to RUCO 11.26(b) states that the "UNS Gas Pension and Benefit lag reflects the payment lag for cash payments made to the pension funds trustees." Since the Accrued Pension Liability represents the liability for pensions that has not been funded, this amount was not covered by cash payments in the lead-lag study.

Q. Does UNSG have an accrued liability for stock-based compensation?

A. No.[17]

Q. How are debit-balance ADIT items generally related to a liability item on a company's balance sheet?

A. In general, debit-balance ADIT items (which appear as assets on a company's balance sheet) are related to a liability item on the Company's balance sheet in the following manner. The liability item multiplied by the income tax rate produces the related ADIT debit-balance. As an illustrative example, assume a $1 million accrued liability and a combined income tax rate of 38.6 percent. The debit-balance ADIT item related to the $1 million accrued liability would be $386,000, computed as follows: $1,000,000 x 38.6% = $386,000. There is typically a direct relationship between the ADIT item and the book-tax timing differences. In many instances, the ADIT is directly related to multiplying a liability (or deferred asset) balance by the income tax rate.

Q. How, specifically, is UNSG's balance of Accrued Vacation Liability related to the ADIT debit-balance item?

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[17] See, e.g., UNSG's responses to RUCO 11.21 (c) and 11.26(c).

A. As explained in UNSG's CONFIDENTIAL response to RUCO 11.22(a): [**BEGIN CONFIDENTIAL**] "

[**END CONFIDENTIAL**] The $169,367 is shown on Attachment RCS-2 to my direct testimony on Schedule B-6, line 8.

Q. How, specifically, is UNSG's balance of Accrued Pension Liability related to the ADIT debit-balance item?

A. The $1,045 ADIT debit balance item on Attachment RCS-2 to my direct testimony on Schedule B-6, line 12, was also computed by UNSG by multiplying a related adjusted liability amount by the combined income tax rate of 38.6 percent. Additional details for such calculation are presented on UNSG's CONFIDENTIAL response to RUCO 11.22(b). Thus, there is an adjusted accrued liability amount of $2,707 related to the ADIT amount of $1,045.

Q. As a result of UNSG's rebuttal testimony have you changed your recommendation about removing the ADIT items listed on Schedule B-6 that was filed with your direct testimony?

A. No. Those adjustments continue to be appropriate. The ADIT related to stock-based compensation should be removed because stock-based compensation should be disallowed for ratemaking purposes, as explained in my direct testimony.

The ADIT related to the Accrued Pension and Vacation Liabilities should be removed because the related Liability balances have not been used to reduce rate base.

Q. Do you have an alternative adjustment to rate base related to the Accrued Pension and Vacation Liability amounts and the ADIT related to those items?

A. Yes. If the ADIT debit-balance items related to the Accrued Pension and Vacation Liabilities of $1,045 and $169,367, respectively, are not removed from rate base, proper matching would require that the cost-free capital related to these ADIT balances in the form of the accrued liability amounts of $2,707 and $438,776 (basically the ADIT amounts divided by the combined income tax rate of 38.6%) should be deducted from rate base, for the net rate base reduction for these items of $271,069 as summarized in the following table:

Description	Adjusted Liability Amount	Combined Income Tax Rate	ADIT Debit Balance	Net Rate Base Impact
	(A)	(B)	(C)	(D) = A+B
Accrued Vacation Liability	$ (438,776)	38.60%	$ 169,369	$ (269,407)
Accrued Pension Liability	$ (2,707)	38.60%	$ 1,045	$ (1,662)
Total of these items	$ (441,483)		$ 170,414	$ (271,069)

IV. ADJUSTMENTS TO OPERATING INCOME

Q. What adjustments to operating income do you address in your Surrebuttal Testimony?

A. I address the following adjustments to operating income, which UNSG has disputed in its Rebuttal Testimony:

- Revenue Annualization
- Incentive Compensation Expense
- Stock Based Compensation Expense
- Supplemental Executive Retirement Plan Expense
- American Gas Association Dues Expense
- Outside Legal Expense
- Fleet Fuel Expense
- Rate Case Expense

- Payroll and Payroll Tax Expense
- Postage Expense

Revenue Annualization

Q. What is UNSG's rebuttal position on the customer annualization adjustment?

A. UNSG witness Bentley Erdwurm presents UNSG's arguments concerning the annualization adjustment. UNSG's rebuttal position is no different than its direct filing. The Company seeks to reduce test year revenue by approximately $516,000.

Q. Why do you disagree with UNSG's proposed customer annualization adjustment?

A. I disagree with UNSG's proposed customer annualization adjustment because it does not make sense to reduce test year revenue when UNSG has continued through the test year to experience year-over-year customer growth. Consequently, I have recommended that the test year revenue be used to set rates, without UNSG's proposed annualization adjustment. I set forth in detail in my direct testimony comparisons of UNSG's residential and commercial customer counts historically and through the test year. I also answered several UNSG data requests concerning the revenue annualization which further explain the rationale for rejecting UNSG's proposed adjustment to reduce test year revenue.

Q. How is a customer annualization typically used in a utility rate case?

A. Where a utility is growing and having to add plant during a test year to serve additional customers, a revenue annualization adjustment is typically employed in order to capture the impact on revenue from customer growth that has occurred and to better match the revenue with the test year plant that has been added to serve the new customers. The revenue growth that relates to the addition of customers is captured in an adjustment to increase revenue related to the increased plant which has been added to serve additional customers during the test year.

Q. How has the customer annualization been applied by UNS Gas in the current rate case?

A. While the Company employed an annualization method similar to the one that was used in its last rate case, the rote application of such method in the current case is <u>decreasing</u> test year revenues. Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer <u>seasonality</u> rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.

Q. Hasn't UNS Gas experienced customer growth?

A. Yes, it has. Year after year, UNSG's number of average customers has been increasing. This holds true for the test year as well. Consequently, because customer counts year-over-year have been increasing for the past several years including the test year, test year revenues should not be decreased based on the misapplication of an annualization adjustment. In other words, while the application of an annualization adjustment may have made sense and been appropriate in UNSG's last rate case to account for customer growth that had occurred during that test year which ended December 31, 2005, rote application of such a method in the current case produces results that do not make sense because it essentially assumes that UNSG is losing residential and commercial customers, when clearly that is NOT the case.

UNS Gas has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to <u>decrease</u> test year revenue would be inappropriate by understating test year and going-forward revenues and should be rejected. Test year revenue of $516,000 should not be removed as proposed by UNSG. RUCO adjustment C-1 filed with my Direct Testimony restores this amount of actual test year revenue to the test year.

Incentive Compensation Expense

Q. What is the basis for UNSG's disagreement with the adjustment to remove 50 percent of the incentive compensation expense?

A. UNSG witness Dukes' Rebuttal Testimony at pages 11-16 addresses this. Basically, UNSG disagrees with the evaluation of who benefits from incentive compensation that has been employed by the Commission in a series of recent decisions on this issue. Mr. Dukes' Rebuttal Testimony generally reiterates arguments that have been considered and rejected by the Commission in prior cases, including the most recent rate cases involving UNSG and its affiliate, UNS Electric.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. What are the key provisions of the incentive compensation program?

A. The Company's response to Staff data request TF 6.64 states that UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). The structure of the PEP determines eligibility for certain bonus levels by measuring UniSource's performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout level. The amount made available for bonuses pursuant to the PEP may range from 15 to 150 percent of the targeted payout level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's response to Staff data request TF 6.64:

> The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Q. Is UNSG's proposed treatment of incentive compensation expense a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. Data request TF 6.103 asked[18]:

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle

[18] See Attachment RCS-5 of my direct testimony.

> established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

UNSG's response to this data request states in part that: "In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensations expense."

Q. What criteria has the Commission found important in deciding issues concerning utility incentive compensation in recent cases?

A. The criteria the Commission has found important in deciding this issue in recent cases are described in various orders which have addressed the treatment of utility incentive compensation expense for ratemaking purposes. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Southwest Gas Corporation's ("SWG") Management Incentive Plan ("MIP") expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Order 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.

Mr. Dukes has not refuted the fact that both shareholders and ratepayers derive some benefit from incentive goals.

Q. Do UNSG's shareholders and customers both benefit from the achievement of incentive compensation program?

A. Yes. Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. Have the facts changed materially since the last UNS Gas rate case that a different result concerning the sharing of incentive compensation expense should occur?

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of this expense in the current case appears to be consistent with the Commission's findings concerning SWG's MIP in Decision No. 68487, and findings about UNSG's incentive compensation expense in Decision No. 70011. In Decision No. 70011 (November 27, 2007), in the last UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. At page 12 of his Rebuttal Testimony, Mr. Dukes claims that Decision No. 69663 supports the UNSG position. Wasn't an equal sharing of incentive compensation expense ordered in other more recent Commission decisions in rate cases involving Arizona utilities?

A. Yes. In Decision No. 70360 (May 27, 2008), in the recent UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a

> reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Finally, in Decision No. 70665 (December 24, 2008), in the most recent Southwest Gas Company rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16 that:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
> > In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]
>
> [3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.
> [4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer

> service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission applied to utility incentive compensation in UNSG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Mr. Dukes?

A. No. The 50/50 sharing of UNSG's incentive compensation program cost ordered by the Commission in Decision No. 70011 should continue to apply in the current UNSG rate case.

Q. Given the current economic conditions, have you seen other utilities volunteering to remove certain compensation from their test year expenses?

A. Yes. I have been seeing increasing examples of this recently where utilities are agreeing to remove discretionary expenses such as incentive compensation, executive raises, SERP, and other expenses, in recognition of the bad economy. As an illustrative example, testimony filed by PEPCO in a D.C. PSC rate case in May 2009, included the following:

- "... the Company has decided to eliminate the 2009 merit increases for its executives and its other non-union management employees."[19]
- "Adjustment 5 excludes from cost of service the costs associated with non-qualified executive retirement plans, as ordered by the Commission in Form Case No. 939 (Order No. 10646, page 128).[20]
- "As noted by Company Witness Kamerick, there will be no adjustment to non-union wages beyond the annualization of the March 1, 2008 increase."[21]
- "Adjustment 22 reflects the exclusion of incentive plan payments in accordance with the Commission's decision in Formal Case No. 1053."[22]

[19] PEPCO witness A.J. Kamerick Direct Testimony (May 2009), page 29, DCPSC Case No. 1076.
[20] PEPCO witness Linda J. Hook Direct Testimony, page 9.
[21] Id at page 13.
[22] Id at page15.

Q. Please summarize your recommendation concerning UNSG's incentive compensation expense.

A. I recommend continuing the 50 percent allocation for UNSG's incentive compensation expense to shareholders ordered by the Commission in Decision No. 70011. This results in a reduction to test year expense of $140,484.

Stock-Based Compensation Expense

Q. What does UNSG claim in its Rebuttal Testimony concerning stock-based compensation expense?

A. UNSG witness Dukes addresses stock based compensation expense at pages 16-17 of his testimony. At page 17, he claims that: "Neither Staff nor RUCO has questioned that the program provides benefits to customers, its prudency, the reasonableness of the cost or that it was incurred to provide service to customers." This statement by Mr. Dukes does not appear to be consistent with the analysis presented in my Direct Testimony. In fact, RUCO is questioning how UNSG's stock-based compensation expense benefits customers and the reasonableness of the additional cost. In fact, especially in view of the poor economic conditions, it would be highly unreasonable to charge UNSG's stock-based compensation expense to ratepayers in the current UNSG rate case. The removal of stock-based compensation expense is consistent with a number of recent Commission decisions that have addressed this issue.

Q. For what types of stock-based compensation has UNSG included an expense in the test year?

A. UNSG has included an expense in the test year for the following types of stock-based compensation:

- Stock Option Expense
- Dividend Equivalents on Stock Units
- Performance Stock Award
- Dividend Equivalent on Stock Options
- Directors Stock Awards

My direct testimony discussed each of these programs.

Q. Did the Commission recently disallow another utility's stock based compensation in a recent decision?

A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a Staff recommendation where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> "APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."
>
> "We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As

> testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's recent decision in the rate case involving UNS Electric, Inc.?

A. Yes, it was. In Decision No. 70360 at page 22, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as APS' last rate case stated:

> "For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663)."

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive compensation that is based on the performance of the Company's (or its parent company's) stock price. Additionally, prior to being required to expense stock options for financial reporting purposes under Statement of Financial Accounting Standards No. 123 Revised (SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While SFAS 123R now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock options from shareholders to utility ratepayers.

Q. Does the poor economic condition present another reason for removing stock-based compensation?

A. Yes. While I believe that UNSG's stock based compensation expense should be removed, even if the economic conditions were better, the current poor economic conditions are causing hardship for customers in many ways, not just related to higher utility rates, and present another reason at this time for removing this expense. In fact, some other utilities have been responding to the poor economic conditions by removing elements of compensation expense from their rate increase request filings. UNSG has taken the opposite approach and continues to litigate such issues. In view of the poor economy, this would be a particularly bad time for the Commission to change from its historical perspective and charge UNSG's ratepayers for stock-based compensation expense.

Q. Please summarize your recommendation.

A. As shown on Attachment RCS-2, Schedule C-4, which was filed with my Direct Testimony, an adjustment should be made to decrease test year expense by $266,399 to reflect the removal of UNSG's stock option compensation expense that is allocated to Arizona operations. The expense of providing stock options and other stock-based compensation to officers, employees and directors beyond their other compensation should be borne by shareholders and not by ratepayers.

Supplemental Executive Retirement Plan Expense

Q. Despite a series of Commission decisions disallowing SERP and the bad economy, is USNG continuing to argue for charging ratepayers for SERP expense?

A. Yes. UNSG witness Dukes' Rebuttal Testimony at pages 17-19 presents essentially the same arguments that were previously presented by this company in its last rate case and by its affiliate, UNS Electric, in its respective last rate case for Supplemental Executive Retirement Plan ("SERP"). There does not appear to be anything new in UNSG's arguments. Such arguments have been previously heard and rejected by the Commission in a series of rate case decisions on utility SERP issues.

Q. At page 18, UNSG witness Dukes claims that SERP is not an excess benefit. What is SERP?

A. The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. How has utility SERP expense been disallowed by the Commission in a series of recent rate cases?

A. To my knowledge, utility SERP expense has been consistently disallowed by the Commission in recent decisions. In Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by

RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Q. Was SERP expense disallowed in the Commission's decision in the last rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> … the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

Q. Was SERP expense also disallowed in the Commission's recent decisions in the rate cases involving UNS Electric, Inc.?

A. Yes, it was. In the recent UNS Electric, Inc. rate case, in Decision No. 70360 at page 22, referencing the above captioned quote, the Commission stated:

> We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

The Commission's Decision No. 70665 (December 24, 2008) in the most recent Southwest Gas rate case, Docket No. G-01551A-07-0504, stated as follows on pages 17-18:

> We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:
>
>> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.
>
> (Decision No. 68487 at 19.)
>
> In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:
>
>> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of

> executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.
>
> [Id. At 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Q. How do the prevailing poor economic conditions affect your analysis of SERP expense?

A. I believe that UNSG's SERP expense should be disallowed for the reasons stated above, even if the economic conditions were better. However, the current poor economic climate represents an additional reason for disallowing this expense. As I have noted elsewhere in my surrebuttal testimony, in view of the poor economy, other utilities have been responding by removing elements of compensation expense. This would be a particularly bad time, therefore, to start charging UNSG ratepayers for an executive compensation expense that has recently been excluded from rates.

Q. Please summarize your recommendation concerning UNSG's SERP expense?

A. I recommend removing UNSG's expense for the SERP.

American Gas Association Dues

Q. Why does UNSG object to a proposed adjustment for American Gas Association dues?

A. This is addressed at UNSG witness Dukes' Rebuttal Testimony at page 21. He opposes the recommended adjustment on the following grounds: (1) Staff did not make the adjustment, and (2) he claims that RUCO adjustment "is based on a 2001 NARUC study that is based on 1999 data" that Mr. Dukes claims is stale and not relevant.

Q. Why didn't Staff make a larger adjustment for AGA dues in the current UNSG rate case?

A. That is not clear.

Q. Did the Commission make a similar adjustment for AGA dues in the most recent Southwest Gas Corporation rate case?

A. Yes. In the most recent Southwest Gas Corporation rate case, I was a witness for Staff and I did recommend a similar adjustment to Southwest's AGA dues, which was adopted by the Commission in Decision No. 70665. The adjustment to UNSG's AGA dues is highly similar to the one adopted by the Commission in Decision No. 70665 and reduces test year expense by $18,678 to reflect the removal of 40 percent of AGA dues. In the current UNSG rate case, I have also recommended the removal of 40 percent of AGA core dues, while UNSG's filing reflected the removal of only 4 percent of the AGA dues.

Q. Is only a 4 percent disallowance of AGA dues-funded activities adequate?

A. No. UNS Gas has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 4 percent is adequate. As I discussed in my Direct Testimony, other states have used a significantly higher disallowance percentage for gas utility AGA dues than UNSG is proposing here. Moreover, a 40 percent disallowance is consistent with the categories of AGA dues established by NARUC, and with the Commission's recent Decision No. 70665 in a Southwest Gas rate case.

Q. In determining the 40 percent disallowance for AGA dues did you rely only on a 2001 NARUC study?

A. No. I relied not only upon information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the Expenditures of the American Gas Association, but also utilized an analysis of the components by function of the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum, discussed in my direct testimony, which contained a 40 percent AGA dues disallowance. I have previously presented copies of relevant pages from the NARUC-sponsored audit reports which were provided in Attachment RCS-4. Additionally, AGA 2007 and 2008 budget information, by component, was summarized in my Direct Testimony filing on Attachment RCS-2, Schedule C-6, page 2.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. How did the Commission address the issue of the appropriate portion of AGA dues to disallow for ratemaking purposes in the most recent Southwest Gas Corporation rate case?

A. The Commission adopted a 40 percent disallowance of AGA dues in Decision No. 70665, in the recent Southwest Gas rate case. In Docket No. G-01551A-07-0504, the Commission adopted Staff's recommendation to disallow 40% of AGA dues. Decision No. 70665, at page 12 stated that:

> We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit.

Q. What amount of UNSG's AGA membership dues expense should be removed from test year expense?

A. I recommend that 40 percent, or $18,678, from the $46,694 of test year expense for AGA membership dues be removed, consistent with the analysis described in my Direct Testimony and above, and consistent with Decision No. 70665. This removes $16,762 more than UNSG's proposed 4 percent removal which amounted to $1,915.

Outside Legal Expense

Q. What is the test year amount of Outside Legal Expense?

A. The Company's test year expense for Outside Legal Expense (other than rate cases) is $83,555. The Company has made a *pro forma* adjustment to increase Outside Legal Expense by $305,984 to "normalize" this expense in the test year, based on a three year average of 2005 - 2007 expenses, which included large annual legal costs related to an El Paso Natural Gas ("EPNG") pipeline case before the FERC.

Q. What is the basic dispute over the amount of Outside Legal Expense?

A. On behalf of RUCO I have recommended an adjustment to remove a portion of UNS Gas' significant *pro forma* increase amount for normalizing outside legal expense in the test year. UNSG witness Dukes' addresses this at pages 27-28 of his Rebuttal Testimony. Mr. Dukes claims at page 27 that: "Both Staff and RUCO fail to provide an allowance for normalized, on-going costs of legal services, based on either historical or projected costs." At page 28, he cites the Commission's Decision No. 70011 in the last UNSG rate case, which allowed UNSG to recover outside legal expenses related to FERC rate cases.

Q. Describe UNS Gas' historical Outside Legal Expenses.

A. The Company spent $488,000, $439,000, and $242,000 in the years 2005, 2006, and 2007 on outside legal costs for matters other than ACC rate cases. A significant amount of these fees in those years are related to the EPNG regulatory proceedings before the FERC, which had settled. The Company's outside legal fees have steadily declined since its last rate case.

Q. Should a backward looking average be used to establish a normalized amount of Outside Legal Expenses in the current UNSG rate case?

A. No, because circumstances have changed. As noted above, UNSG's outside legal expenses have decreased. In Decision No. 70011 (November 27, 2007), the Commission stated (at page 20) that "We believe that the Company's allowable legal expenses should be set at a level that reflects more accurately its actual experience, both historical and anticipated." I generally agree with this statement, but am specifically concerned that it not be transformed into a recipe for charging ratepayers prospectively for abnormally high levels of legal expense incurred by a utility in years prior to the test year; consequently, RUCO generally agrees with the principle of allowing for a normalized and reasonable level of legal expense, but cautions against transforming this principle into a means for retroactive recovery by a utility of its past year's legal costs, particularly in years when such costs may have been abnormally high.

Q. In what FERC proceedings has UNSG participated?

A. A listing of the FERC proceedings in which UNSG has participated was provided in response to UNSG's CONFIDENTIAL response to RUCO 11.11.

Q. Has UNSG demonstrated that its outside legal expense has been cost-effective?

A. No. In response to data request RUCO 11.6, RUCO 11.11(g) and others, UNSG has indicated that it does not have any analysis on the impact of its participation in any of the FERC proceedings.

Q. At page 28 of his rebuttal testimony, Mr. Dukes refers to a current El Paso Natural Gas system wide rate case at FERC, Docket No. RP08-426. Does UNSG have a budget for costs related to that docket?

A. UNSG was asked about this in data request RUCO 11.5a. UNSG's CONFIDENTIAL response states that: [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. Has UNSG provided additional information about that El Paso Natural Gas system wide rate case at FERC?

A. Yes. UNSG's CONFIDENTIAL response to RUCO 11.5 provides some additional information on FERC Docket No. RP08-426.[23]

Q. Are any of UNSG's affiliates also customers of El Paso Natural Gas and/or are intervening in FERC Docket No. RP08-426?

A. Yes. UNSG's CONFIDENTIAL response to RUCO 11.5(k) states that: [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. How are costs of participating in FERC Docket No. RP08-426 being allocated among UNSG and its affiliates?

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[23] UNSG's response to RUCO 11.5, without voluminous attachments, is included in Attachment RCS-9 to my Surrebuttal Testimony.

A. UNSG's CONFIDENTIAL response to RUCO 11.5(m) states that: [**BEGIN CONFIDENTIAL

[**END CONFIDENTIAL**]

Q. Was the cost of participating in the last El Paso Natural Gas case allocated among UNSG and its affiliates?

A. According to the response to RUCO 11.8, apparently there was no apportionment of the cost of participating in the last EPNG FERC rate case. UNSG's response to RUCO 11.8 states that: "In its last rate case, FERC Docket NO. 95-363, EPNG filed its Settlement Proposal on December 6, 2007. FERC issued its order accepting the Settlement Proposal on August 31, 2007. TEP did not become a customer of EPNG until April 2007; therefore, TEP did not participate in the rate case." In response to RUCO 11.8(b), which had asked about the apportionment of the cost of participating in the FERC case among each of UNSG's affiliates, UNSG responded: "N/A." Consequently, none of the cost to UNSG from participating in the last EPNG FERC rate case was apportioned to other affiliates, such as TEP; however, in the future, there would be a [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**] as described in the response to RUCO 11.5(m). This is a significant change in circumstances, and should warrant not using UNSG's prior year FERC related costs as the basis for setting a "normal" level in the current case, at minimum, without some significant discounting of such past costs to reflect the fact that

UNSG did not share such costs with its affiliates in the past, but would be doing so on a going-forward basis.

Q. At page 28 of his Rebuttal Testimony, Mr. Dukes mentions that Transwestern is expected to file for a system-wide rate case at FERC in 2011. Do you have any other information about that anticipated filing?

A. Yes. UNSG's response to RUCO 11.35(d) indicates that [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. Has UNSG provided its budgets for "Outside Legal Services"?

A. Not to the extent requested. UNSG's response to RUCO 11.35(b) and (c) state, respectively that: [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. What amount of outside legal expense are you recommending?

A. Based on a review of the additional material provided by UNSG in response to RUCO set 11, I recommend that if the Commission is inclined to give UNSG more money for outside legal expense, that it not base the amount on a mere average of historical expenditure levels because circumstances have changed and UNSG's budget for outside legal has decreased. The amount allowed in this case should in no event be higher than UNSG's 2009 budget, which was provided in the CONFIDENTIAL response to RUCO 11.35. In my direct testimony I had recommended an allowance of $171,865. Because it appears that some level of EPNG FERC costs will be ongoing, I had provided for an annual amount for EPNG FERC proceedings of approximately $100,000 based on actual test year costs. As shown on Schedule C-7, this adjustment had reduced UNSG's requested outside legal expense by $217,674. The annual amount of $171,865 of normalized outside legal expense that I had recommended in my direct testimony should be adequate in view of the fact that future FERC costs will be allocated between UNSG and TEP. Moreover, UNSG has not presented a cost-benefit analysis, or an evaluation of the impact of its legal expenditures.

Fleet Fuel Expense

Q. What is the dispute concerning Fleet Fuel Expense?

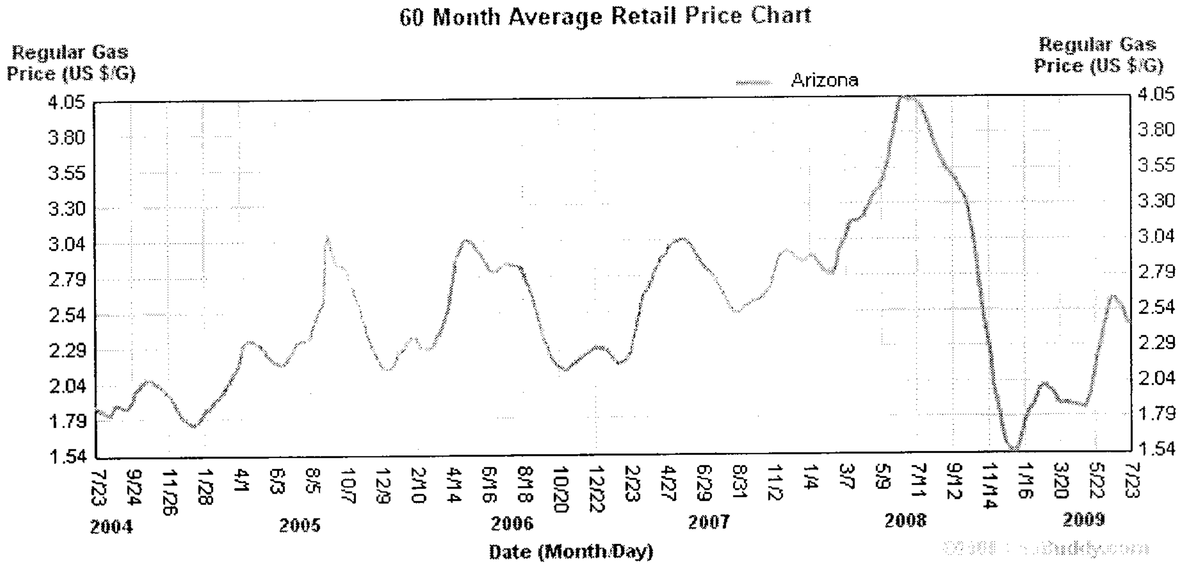
A. UNSG witness Dukes addresses this at pages 29-31 of his Rebuttal Testimony. All parties – UNSG, Staff and RUCO – appear to agree that the test year level of expense needs to be adjusted to a "normal" level given the extreme volatility of fuel expense; however, the parties do not agree upon the amount of adjustment. My reasons for recommending a normalizing adjustment include that the test year fleet fuel expense was based on unusually high fuel prices in effect during the test year, in some months over $4.00 a gallon, the country's record high point. The amount of gallons purchased in the test year is also the highest among historical yearly gallons purchased.

Mr. Dukes appears to agree with the use of a three-year average of fuel usage to normalize the expense. However, he wants to apply a backward-looking cost of fuel that includes the extreme peak costs during 2008 in order to normalize the cost.

At page 30, Mr. Dukes also identifies two technical corrections to the adjustment calculation I had presented with my direct testimony: (1) remove an additional amount inadvertently included and (2) reflect an O&M expense allocation of 73.4 percent. I agree with Mr. Dukes about these two points and will reflect appropriate corrections.

Q. Do you agree with the concept of using an average for fuel prices?

A. Yes. Because the cost has been so volatile, using an average is appropriate to derive a normalized amount. However, I do not agree with Mr. Dukes that a backward-looking average of 2006-2008 prices is necessarily representative of current and expected prices. Based on the following chart, gasoline prices in Arizona reached extreme levels in 2008, over $4 per gallon, and have been significantly lower before and since.



Q. In response to RUCO discovery, did UNSG provide more current information on Fleet Fuel Expense?

A. Yes. In response to RUCO 11.36(f), UNSG provided average fuel prices for the 36-months through June 2009.

Q. Have you updated RUCO's adjustment for Fleet Fuel Expense?

A. Yes. Attachment RCS-7, Schedule C-8 Revised shows the updated adjustment. This adjustment uses an average fuel cost of $2.95 per gallon based on January 2006 through June 2009 information. The incorporation of more current information and a longer period helps mitigate the impact of the extreme peak gasoline prices of mid-2008. This average cost of fuel also is reasonable in view of the graph of historic Arizona gasoline prices from ArizonaGasPrices.com depicted on the above chart. As shown on Schedule C-8 Revised, page 1 of 3, I have reduced fleet fuel expense by $71,963. This exceeds the $51,258 reduction proposed by UNSG in its Rebuttal Testimony by $20,705.

Q. What is shown on Schedule C-8 Revised, pages 2 and 3?

A. Schedule C-8 Revised, page 2, shows the monthly Fleet Fuel Expense, including cost per gallon for January 2006 through June 2009, based on information provided by UNSG in response to data requests RUCO 10.1 and 11.36. Schedule C-8 Revised, page 2, shows the allocation of the adjustment for Fleet Fuel Expense proposed in UNSG's Rebuttal Testimony and RUCO's recommendation, and the difference, by FERC account.

Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. UNS Gas is requesting recovery of $500,000 for current rate case expenses over three years for an annual allowance of $166,667 per year. Mr. Dukes' Rebuttal Testimony at page 19 indicates that the Company expects to incur more than that, inclusive of the substantial TEP employee time charged for UNSG rate case cost and outside counsel. UNSG has agreed with an adjustment to remove an amortization of $100,000 of unamortized rate case expense from the prior rate case and proposed that it should also be normalized over three years for an additional amount of $33,333, which brought the Company's request for *pro forma* total rate case expense to $200,000 per year. The Company stated in response to Staff data request TF 6.68 that it did not remove amortization of rate case expense related to the previous rate case that will be recovered prior to new rates becoming effective. Therefore, the Company's test year amount of rate case expense included an additional $58,333. The response to TF 6.68 also states that this amount would be removed resulting in a reduction of test year rate case expense of $58,333.

Q. Do you agree with the Company's proposed amount of rate case expense for this case of $500,000?

A. No. Even with the Company's proposed correction, the total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization.

Q. What total amount of rate case expense was allowed in the last UNSG rate case?

A. The allowance for rate case expense was based on a total amount of $300,000 for rate case expenses in its prior rate case, Docket No. G-04204A-06-0463, normalized over a period of three years.

Q. How does the current UNSG rate case compare with the last UNSG rate case?

A. The current UNS Gas rate case is similar to and presents many of the same issues and adjustments to rate base and operating expenses (i.e., CWIP, property taxes, incentive compensation, etc.), if not less, than those that were addressed by the Commission in the Company's last rate case. For example, in the prior rate case, it was the Company's first case under its new ownership. The Company also conducted a depreciation study supporting new depreciation rates in the prior case. UNS Gas is not proposing to revise its depreciation rates in this case.

Q. What do you recommend for the allowance for rate case expense for UNS Gas in this proceeding?

A. I recommend an annual allowance of $100,000, based on normalizing a total amount of $300,000 over a three-year period. The $500,000 for current rate case cost requested by UNS Gas is nearly double (i.e., is almost 81 percent higher) the amount of rate case expense requested and allowed by the Commission in the Southwest Gas' last rate case, Docket No. G-01551A-07-0504, which was $276,000 in total and was normalized over a three-year period, to produce an annual allowance of $92,000 per year. The rate case expense allowance in the last UNS Gas case was $100,000, based on normalizing a total amount of $300,000 over three years.

Q. How does your recommended allowance for rate case expense for UNS Gas in this proceeding compare with the allowed rate case expense for UNSG's affiliate, UNS Electric, in that utility's last Arizona base rate case?

A. The rate case allowance in the last UNS Electric rate case was $100,000, based on normalizing a total amount of $300,000 over three years. My recommended allowance for UNSG is comparable to the Commission's allowance for rate case cost in the last UNS Electric rate case.

Q. How does the current UNS Gas rate case proceeding compare with range of issues for UNSG in its last rate case and for and UNSG's affiliate, UNS Electric, in that utility's last Arizona base rate case?

A. The current UNS Gas rate case has similarities to the last UNS Gas and UNS Electric rate cases in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff.

Q. Please summarize your recommended adjustment.

A. I recommend an annual allowance of $100,000 per year, based on a total of $300,000 normalized over three years. Schedule C-9 filed in Attachment RCS-2 with my direct testimony reduces the Company's proposed annual allowance for current rate case costs by $100,000.

I also recommend that the amount recorded by UNS Gas in the test year of $58,333 for prior rate case expense be removed. The Company's response to Staff data request TF 6.68 indicates this adjustment is needed to correct an error in UNS Gas' filing.

As shown on Schedule C-9, my total adjustment allows for a $100,000 per year normalized rate case expense, and reduces the rate case expense in UNSG's filing by $158,333.

2010 Pay Increase

Q. What does UNSG's Rebuttal Testimony dispute about your recommended disallowance of a projected 2010 pay increase?

A. UNSG witness Dukes addresses this issue at pages 9-10 of his Rebuttal Testimony. Mr. Dukes disagrees with this adjustment because: (1) Staff did not object to the Company's payroll adjustments in Staff's direct testimony; (2) the argument that the adjustment is too far outside of the test year was made by RUCO in prior Southwest Gas cases and was rejected by the Commission; (3) there is no mis-match with the test year that ended June 30, 2008 because the new rates are not likely to go into effect until January 2010, and the increase is attributable to the current work force. As to the non-union increase, Mr. Dukes claims that "the increase will be known prior to rates going into effect and support of the approved increase can be provided prior to the close of the record."[24]

Q. Please respond to Mr. Dukes' rebuttal on this issue.

A. I acknowledge that in prior Southwest Gas rate cases, the Commission has allowed a second round of beyond the test year rate increases. Additionally, I agree with Mr. Dukes that it appears that Staff's direct filing made no adjustment to remove or adjust the projected January 2010 pay increase.

The projected increase for January 2010 particularly for non-union employees, however, is not known or certain at this time. That amounts to $96,088, per UNSG's response to RUCO 11.40(b).

Moreover, I have seen other utilities curtailing projected wage increases and cutting back compensation and benefits in response to the poor economy. Additionally, the economic climate in Arizona in mid-2009 is worse than it was in each of the last Southwest Gas filings, as UNSG admits in its response to RUCO 11.40(e). Consequently, I believe there may be compelling circumstances in the context of the current UNSG rate case, including the poor economic climate, that did not exist in the context of the prior Southwest Gas cases, and which may warrant a different treatment of estimated future pay increases that would occur more than one year beyond the test year.

Q. Please elaborate on how some other utilities have responded to the poor economic climate by addressing payroll and benefits.

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[24] Dukes Rebuttal Testimony, page 10, lines 13-15.

A. In a current rate filing in Vermont, Green Mountain Power has limited the increases in compensation to the contractual rate for bargaining employees and has frozen wages for non-bargaining employees. Potomac Electric Power Company ("PEPCO") in its current filing in Washington D.C. PSC Case No. 1076 has indicated that there will be no wage increase for non-bargaining employees in 2009, thus there is no adjustment to non-union wages in its filing beyond the annualization of a March 1, 2008 increase. Additionally, PEPCO included a 1.5 percent July 1, 2009 increase for union wages, even though the annual contractual increase for the past several years had been 3 percent. Peoples Gas System in Florida PSC Docket No. 080318-GU eliminated the executive increase and reduced the employees' compensation increases.

Q. Please summarize your recommendation concerning the January 2010 pay increase.

A. I recommend that the Commission remove this expense and the related payroll tax expense for the reasons described in my Direct Testimony and above.

Postage Increase

Q. Page 31 of UNSG witness Dukes' Rebuttal Testimony addresses a postage adjustment proposed by Staff. Do you agree that an adjustment should be made for a known and measurable increase in postage rates that has occurred?

A. Yes, and the amount of such adjustment should be appropriately coordinated with the test year number of customers. As explained above, I have disagreed with UNSG's proposal to decrease test year revenue for a customer annualization adjustment. Consequently, my test year recommendations reflect the actual test year customers, not the reduced level advocated by UNSG. Consequently, the postage adjustment consistent with RUCO's filing is slightly higher than as proposed by UNSG. As shown on Attachment RCS-7, Schedule C-13, the impact of the 2 cent postage rate increase on the unadjusted test year customer billings is $34,782. This amount exceeds the $12,750 postage adjustment in UNSG's direct filing by $22,031.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

UNS GAS, INC.
FLEET FUEL EXPENSE
Updated Adjustment

Line No.	Description	2006 (A)	2007 (B)	2008 (C)	YTD June 2009 (D)	Normalized Based Upon Average (E)	Test Yr. (F)	Pro Forma Fuel Adjustment (G)
	I. Per UNSG Rebuttal							
1	Gallons	221,734	228,106	221,120		**223,653**	228,369	
2	Miles Driven	3,607,551	3,607,551	2,314,954		**3,176,685**	2,960,186	
3	Fuel Cost	$608,781	$664,365	$779,691		**$684,279**	$753,931	
4	Cost per Gallon	$2.73	$2.92	$3.50		**$3.06**	$3.30	
5	Percentage Allocated to O&M	73.4%	73.4%	73.4%		**73.4%**	73.4%	
6	**Expense Level**	$ 446,845	$ 487,644	$ 572,293		$ **502,261**	$ **553,519**	$ (51,258)
	II. Per RUCO Surrebuttal							
7	Gallons	221,734	228,106	221,120	107,241	222,343	228,369	
8	Miles Driven	3,607,551	3,607,551	2,314,954	1,132,843	3,046,543	2,960,186	
9	Fuel Cost	$ 608,781	$ 664,365	$ 779,691	$ 243,414	$ 656,071	$ 753,931	
10	Cost per Gallon	$ 2.75	$ 2.91	$ 3.53	$ 2.27	$ 2.95	$ 3.30	
11	Percentage Allocated to O&M	73.4%	73.4%	73.4%	73.4%	73.4%	73.4%	
12	**Expense Level**	$ 446,845	$ 487,644	$ 572,293	$ 178,666	$ **481,556**	$ **553,519**	$ (71,963)
13	**Difference**					$ (20,705)		$ (20,705)

Notes and Source
Per UNSG: Response to RUCO 10.1 - Income - Fleet Fuel Expense (Excel file)
Line 4: Per UNSG workpaper provided in resposne to RUCO 10.1; difference between this and results of Line 3 / Line 1 attributable to UNSG showing a simple average, rather than a weighted average
Line 10: Line 9 / Line 7
Col.D: UNSG response to RUCO 11-36 - see summary at page 2 of this Schedule
Col.E: Sum of Columns A-D / 3.5 years

UNS GAS, INC.
CALENDAR YEAR 2006
RUCO 1.94 DATA - CORRECTED

Fleet Fuel Expense by Month, January 2006 through June 2009

Included in "RUCO 10.1 - Income - Fleet Fuel Expense.xls" as backup for Dukes rebuttal testimony

Month	Amount	$/Gal	Gallons	Miles
Jan-06	$52,838.48	$2.51	21,019	
Feb-06	$42,722.90	$2.51	17,029	
Mar-06	$49,847.40	$2.59	19,210	
Apr-06	$54,739.50	$2.94	18,609	
May-06	$61,607.25	$3.13	19,672	
Jun-06	$57,594.59	$3.02	19,066	
Jul-06	$58,480.84	$3.01	19,439	
Aug-06	$58,787.62	$2.98	19,698	
Sep-06	$52,430.22	$2.67	19,618	
Oct-06	$44,502.16	$2.46	18,113	
Nov-06	$42,569.04	$2.47	17,257	
Dec-06	$32,660.68	$2.51	13,004	
Totals	**$608,780.68**	**$2.73**	**221,734**	**0**

Supplemental Response to RUCO 1.94

The "Miles" column in the Excel file RUCO 1.94 2006 was left blank when submitted to RUCO, without explanation. The reason this column is blank is that in 2006 the UNS Gas vehicles had not been fully loaded into the Tucson Electric Power Fleet Management system. UNS Gas is unable to give an accurate mileage account for 2006. The miles traveled in 2007 should be close to what was traveled in 2006.

Month	Amount	$/Gal	Gallons	Miles
Jan-07	$47,254.96	$2.43	19,413	287,170
Feb-07	$43,322.76	$2.48	17,468	286,775
Mar-07,	$56,357.48	$2.74	20,549	315,877
Apr-07	$55,147.78	$2.99	18,445	332,610
May-07	$60,392.52	$3.09	19,551	273,648
Jun-07	$58,311.73	$3.07	18,999	357,882
Jul-07	$62,799.71	$3.00	20,954	310,803
Aug-07	$58,317.27	$2.85	20,436	352,954
Sep-07	$52,494.63	$2.85	18,441	281,905
Oct-07	$58,071.08	$3.00	19,349	299,792
Nov-07	$58,494.37	$3.26	17,947	328,348
Dec-07	$53,400.33	$3.23	16,554	179,787
Totals	**$664,364.62**	**$2.92**	**228,106**	**3,607,551**
Jan-08	$74,435.43	$3.17	23,502	216,237
Feb-08	$62,546.23	$3.26	19,215	220,381
Mar-08	$67,434.32	$3.58	18,843	207,156
Apr-08	$73,497.80	$3.73	19,685	178,971
May-08	$79,282.01	$4.05	19,568	200,136
Jun-08	$66,565.85	$4.35	15,302	183,716
Jul-08	$83,015.15	$4.32	19,234	171,416
Aug-08	$73,090.59	$3.97	18,392	210,901
Sep-08	$70,153.68	$3.78	18,552	166,329
Oct-08	$61,567.95	$3.24	18,993	217,413
Nov-08	$39,643.15	$2.50	15,859	147,355
Dec-08	$28,458.38	$2.04	13,975	194,943
Totals	**$779,690.54**	**$3.50**	**221,120**	**2,314,954**
Jan-09	$43,261.78	$2.12	20,439	191,693
Feb-09	$36,315.38	$2.20	16,500	163,407
Mar-09	$37,587.88	$2.12	17,693	204,036
Apr-09	$41,342.35	$2.32	17,794	190,434
May-09	$42,135.68	$2.28	18,506	182,493
Jun-09	$42,770.81	$2.62	16,309	200,780
Totals	**$243,413.88**	**$2.28**	**107,241**	**1,132,843**

Source: UNSG Response to RUCO 11-36

UNS GAS, INC.
FLEET FUEL EXPENSE
Updated Adjustment
Allocation to FERC Expense Accounts

Line No.	FERC Account	Percent	Allocation UNSG Reb. Adjustment	Allocation RUCO Surreb. Adjustment	Difference
		(A)	(B)	(C)	(D)
1	0807	0.08%	$ (41)	$ (58)	$ (17)
2	0856	0.15%	$ (75)	$ (105)	$ (30)
3	0870	3.28%	$ (1,682)	$ (2,362)	$ (680)
4	0874	15.18%	$ (7,779)	$ (10,922)	$ (3,142)
5	0875	2.14%	$ (1,098)	$ (1,542)	$ (444)
6	0876	1.97%	$ (1,012)	$ (1,421)	$ (409)
7	0877	0.31%	$ (160)	$ (224)	$ (64)
8	0878	14.28%	$ (7,321)	$ (10,278)	$ (2,957)
9	0879	5.55%	$ (2,844)	$ (3,993)	$ (1,149)
10	0880	7.11%	$ (3,646)	$ (5,118)	$ (1,473)
11	0885	2.69%	$ (1,377)	$ (1,934)	$ (556)
12	0887	5.83%	$ (2,989)	$ (4,196)	$ (1,207)
13	0889	0.17%	$ (85)	$ (119)	$ (34)
14	0891	0.03%	$ (15)	$ (21)	$ (6)
15	0892	4.77%	$ (2,443)	$ (3,430)	$ (987)
16	0893	1.51%	$ (773)	$ (1,085)	$ (312)
17	0894	0.09%	$ (48)	$ (67)	$ (19)
18	0901	0.55%	$ (283)	$ (397)	$ (114)
19	0902	8.97%	$ (4,598)	$ (6,455)	$ (1,857)
20	0903	11.20%	$ (5,740)	$ (8,058)	$ (2,318)
21	0905	0.03%	$ (13)	$ (19)	$ (5)
22	0908	1.01%	$ (520)	$ (729)	$ (210)
23	0921	-0.28%	$ 146	$ 205	$ 59
24	0921	13.20%	$ (6,767)	$ (9,500)	$ (2,733)
25	0930	0.01%	$ (3)	$ (4)	$ (1)
26	0932	0.19%	$ (96)	$ (134)	$ (39)
27	Totals	100.00%	$ (51,260)	$ (71,965)	$ (20,705)
28	**Total Adjustment from page 1**		**$ (51,258)**	**$ (71,963)**	**$ (20,705)**

Notes and Source
Per UNSG: Response to RUCO 10.1 - Income - Fleet Fuel Expense (Excel file)
Line 27: difference between amount on line 21 and amount from page 1 due to rounding

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

Docket No. G-04204A-08-0571
Attachment RCS-7
Schedule C-13 (new)
Page 1 of 1

Line No.	Description		Amount	Reference
1	Number of Customer Bills - Unadjusted		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Unadjusted customers	$	34,782	Line 1 * Line 2
4	UNSG Customer Annualization			UNSG Schedule H2 P1
5	RUCO Customer Annualization Postage	$	-	Line 4 * .44
6	Postage Expense Adjustment - Increase Expense	$	34,782	Line 3 + Line 5
7	Less: UNSG Postage Expense Adjustment As Filed (Bates Nos. UNSG0571/02494 & UNSG0571/02555 - 02562)		$12,750	Misc Expenses Pro Forma
8	Incremental RUCO Postage Expense Adjustment	$	22,031	Line 6 - Line 7

Notes and Source

UNSG's response to RUCO 11-46

Line 4: RUCO recommends rejection of UNSG's proposed Customer Annualization, which would decrease test year revenue.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-8
Copies of Non-Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO-10.1	Mr. Dukes' Rebuttal supporting workpaper for UNSG's proposed revised payment lag for Purchased Gas Expense	No	1	2
RUCO-11-6	No analysis of impact of participation in previous El Paso rate case at FERC	No	1	3
RUCO-11-8	Affiliate TEP became a customer of El Paso after last EPNG rate case at FERC	No	1	4
RUCO-11-9	No analysis of impact of participation in previous Transwestern Pipeline rate case at FERC	No	1	5
RUCO-11-10	Allocation of FERC proceeding costs among UNSE's affiliates	No	1	6
RUCO-11-12	UNSG intervention in FERC proceedings; no analysis of impact of participation	No	4	7 - 10
RUCO-11-13	UNSG's calculation of $9 million and $5.4 million amounts on page 2 of Hutchens' rebuttal testimony	No	2	11 - 12
RUCO-11-18	UNSG cost savings not reflected in the test year	No	1	13
RUCO-11-19	Annual cost reduction from having Walmart accept customer payments	No	1	14
RUCO-11-21	Accrued liability for vacation related to ADIT debit-balance items	No	1	15
RUCO-11-24	ADIT treatment for rate base	No	1	16
RUCO-11-25	ADIT treatment for rate base	No	1	17
RUCO-11-26	Lead lag treatment for accrued vacations and accrued pension liability	No	1	18
RUCO-11-27	Cash working capital: Purchased gas payment lag (without voluminous attachments)	No	4	19 - 22
RUCO-11-28	Post test year plant admissions	No	2	23 - 24
RUCO-11-30	UNSG reviewed CWIP for post test year plant	No	1	25
RUCO-11-32	Customer Advances admissions	No	2	26 - 27
RUCO-11-36	Fleet Fuel Expense (without voluminous attachments)	No	4	28 - 31
RUCO-11-38	Assumption detail for Grant rebuttal testimony 2009-2011 forecasts: not appropriate for ratemaking	No	10	32 - 41
RUCO-11-40	Projected 2010 Payroll Expense adjustment	No	3	42 - 44
RUCO-11-46	Postage expense	No	8	45 - 52
	Total Pages Including this Page		52	

UNS Gas
Purchased Gas Lag
Test Year Ending June 30, 2008

Service Month	Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
BP Energy Company						
July -	7/1/2007	7/31/2007	2,892,390	8/20/2007	35.00	101,233,667
August -	8/1/2007	8/31/2007	2,811,862	9/20/2007	35.00	98,415,166
September -	9/1/2007	9/30/2007	2,693,603	10/22/2007	36.50	98,316,498
October -	10/1/2007	10/31/2007	5,507,132	11/20/2007	35.00	192,749,607
November -	11/1/2007	11/30/2007	7,297,535	12/20/2007	34.50	251,764,943
December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	22.00	352,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	14.00	140,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	12.50	112,500,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	12.00	108,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	25.50	239,029,379
March -	3/1/2008	3/31/2008	12,389,177	4/22/2008	37.00	458,399,562
April -	4/1/2008	4/30/2008	7,801,472	5/22/2008	36.50	284,753,743
May -	5/1/2008	5/31/2008	7,264,481	6/20/2008	35.00	254,256,849
June -	6/1/2008	6/30/2008	7,826,991	7/21/2008	35.50	277,858,167
			109,858,344			2,969,277,581
El Paso Natural Gas Co						
July -	7/1/2007	7/31/2007	379,421	8/24/2007	39.00	14,797,438
August -	8/1/2007	8/31/2007	377,627	9/25/2007	40.00	15,105,098
September -	9/1/2007	9/30/2007	388,581	10/25/2007	39.50	15,348,942
October -	10/1/2007	10/31/2007	438,071	11/25/2007	40.00	17,522,849
November -	11/1/2007	11/30/2007	976,464	12/21/2007	35.50	34,664,462
December -	12/1/2007	12/31/2007	1,273,618	1/25/2008	40.00	50,944,716
January -	1/1/2008	1/31/2008	1,267,429	2/25/2008	40.00	50,697,160
February -	2/1/2008	2/28/2008	1,239,857	3/24/2008	39.50	48,974,366
March -	3/1/2008	3/31/2008	1,190,404	4/22/2008	37.00	44,044,947
April -	4/1/2008	4/30/2008	568,207	5/27/2008	41.50	23,580,588
May -	5/1/2008	5/31/2008	338,302	6/23/2008	38.00	12,855,459
June -	6/1/2008	6/30/2008	352,906	7/25/2008	39.50	13,939,806
			8,790,888			342,475,831
Transwestern Pipeline Co						
July -	7/1/2007	7/31/2007	104,768	8/13/2007	28.00	2,933,518
August -	8/1/2007	8/31/2007	104,727	9/14/2007	29.00	3,037,089
September -	9/1/2007	9/30/2007	101,557	10/12/2007	26.50	2,691,256
October -	10/1/2007	10/31/2007	260,164	11/9/2007	24.00	6,243,936
November -	11/1/2007	11/30/2007	252,179	12/13/2007	27.50	6,934,912
December -	12/1/2007	12/31/2007	263,779	1/14/2008	29.00	7,649,581
January -	1/1/2008	1/31/2008	264,531	2/11/2008	26.00	6,877,800
February -	2/1/2008	2/28/2008	246,162	3/13/2008	28.50	7,015,611
March -	3/1/2008	3/31/2008	302,830	4/11/2008	26.00	7,873,585
April -	4/1/2008	4/30/2008	331,575	5/12/2008	26.50	8,786,729
May -	5/1/2008	5/31/2008	241,646	6/12/2008	27.00	6,524,454
June -	6/1/2008	6/30/2008	182,318	7/11/2008	25.50	4,649,105
			2,656,236			71,217,578
			121,305,468			3,382,970,990
Average Lag Days				27.89		

Current Payments made to BP Energy after TY Ending June 30, 2009

Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
7/1/2008	7/31/2008	4,755,012	8/20/2008	35.00	166,425,403
8/1/2008	8/31/2008	3,813,688	9/22/2008	37.00	141,106,473
9/1/2008	9/30/2008	1,169,749	10/15/2008	29.50	34,507,591
10/1/2008	10/31/2008	1,589,392	11/25/2008	40.00	63,575,692
11/1/2008	11/15/2008	2,932,485	11/25/2008	17.00	49,852,248
11/16/2008	11/30/2008	4,333,170	12/8/2008	15.00	64,997,546
12/1/2008	12/15/2008	3,717,098	12/22/2008	14.00	52,039,373
12/16/2008	12/31/2008	7,194,073	1/8/2009	15.50	111,508,127
12/16/2008	12/31/2008	956,319	1/20/2009	27.50	26,298,784
1/1/2009	1/15/2009	3,760,981	1/22/2009	14.00	52,653,733
1/16/2009	1/31/2009	6,411,461	2/6/2009	13.50	86,554,721
2/1/2009	2/15/2009	3,422,333	2/20/2009	12.00	41,067,995
2/16/2009	2/28/2009	4,187,566	3/6/2009	12.00	50,250,797
3/1/2009	3/15/2009	3,261,816	3/20/2009	12.00	39,141,796
3/16/2009	3/31/2009	3,548,797	4/9/2009	16.50	58,555,151
4/1/2009	4/15/2009	1,609,806	4/24/2009	16.00	25,756,903
4/16/2009	4/30/2009	1,481,302	5/8/2009	15.00	22,219,537
5/1/2009	5/15/2009	747,245	5/26/2009	18.00	13,450,402
5/16/2009	5/31/2009	791,607	6/10/2009	17.50	13,853,120
		59,683,901			1,113,815,392
			18.66		

Payment Lag Adjustment - For Rebuttal

Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
BP Energy Company					
12/1/2008	12/15/2008	3,717,098	12/22/2008	14.00	52,039,373
12/16/2008	12/31/2008	7,194,073	1/8/2009	15.50	111,508,127
12/16/2008	12/31/2008	956,319	1/20/2009	27.50	26,298,784
1/1/2009	1/15/2009	3,760,981	1/22/2009	14.00	52,653,733
1/16/2009	1/31/2009	6,411,461	2/6/2009	13.50	86,554,721
2/1/2009	2/15/2009	3,422,333	2/20/2009	12.00	41,067,995
2/16/2009	2/28/2009	4,187,566	3/6/2009	12.00	50,250,797
3/1/2009	3/15/2009	3,261,816	3/20/2009	12.00	39,141,796
3/16/2009	3/31/2009	3,548,797	4/9/2009	16.50	58,555,151
4/1/2009	4/15/2009	1,609,806	4/24/2009	16.00	25,756,903
4/16/2009	4/30/2009	1,481,302	5/8/2009	15.00	22,219,537
5/1/2009	5/15/2009	747,245	5/26/2009	18.00	13,450,402
5/16/2009	5/31/2009	791,607	6/10/2009	17.50	13,853,120
		41,090,405			593,350,439
			14.44		
El Paso Natural Gas Co					
		8,790,888			342,475,831
Transwestern Pipeline Co					
		2,656,236			71,217,578
		52,537,528			1,007,043,848
			19.17		

(a) Measured from midpoint of service month to payment date.

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.6 Does UNSG have any analyses of the impact of its participation in the last EPNG rate case at FERC? If not, explain fully why not. If so, please identify, explain and provide a copy of all such analyses.

RESPONSE: UNS Gas does not have any analysis on the impact of its participation in the last EPNG rate case at FERC. It is impossible to determine the impact of one individual company's participation in a case whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.8 Did the last EPNG rate case at FERC have any impact on UNSG's affiliate, Tucson Electric Power? If not, explain fully why not. If so, please identify, quantify and explain the potential impact.

a. Show the total amount of cost from participating in that FERC case by component.
b. Show in detail how the cost of participating in that FERC case was apportioned among each of the affiliates.

RESPONSE: In its last rate case, FERC Docket No. 95-363, EPNG filed its Settlement Proposal on December 6, 2007. FERC issued its order accepting the Settlement Proposal on August 31, 2007. TEP did not become a customer of EPNG until April 2007; therefore, TEP did not participate in the rate case.

a. Not applicable.

b. Not applicable.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

RUCO 11.9 Does UNSG have any analyses of the impact of its participation in the last Transwestern Pipeline rate case at FERC? If not, explain fully why not. If so, please identify, explain and provide a copy of all such analyses.

RESPONSE: UNS Gas does not have any analysis on the impact of its participation in the last Transwestern Pipeline rate case at FERC. It is impossible to determine the impact of one individual company's participation in a case, whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.10 How does UNSG coordinate the cost of participating in FERC proceedings with its affiliates, including but not limited to TEP, UNS Electric, and others? Explain fully.

RESPONSE: In matters where UNS Gas and other affiliates intervene, expenses would be allocated equally.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.12 Refer to Mr. Dukes' rebuttal testimony at pages 27-28. Please provide the following information for each year, 2004-2008 and for year-to-date 2009:

a. Identify each FERC case in which UNSG has participated.
b. Identify the cost of UNSG's participation in each such FERC case, by amount and by account.
c. Identify the outside legal cost of UNSG's participation in each such FERC case, by amount and by account.
d. Identify and explain the issues that concerned UNSG in each such FERC case.
e. Identify, quantify and explain the impact that UNSG's participation had on the results of each such FERC case.
f. Provide all analyses and cost-benefit evaluations that UNSG has documenting the impact of UNSG's participation and litigation in each such FERC case.
g. Provide all documentation used by UNSG in its evaluation of how much legal expense to incur on each such FERC case.

RESPONSE: a. UNS Gas objects to providing information for years 2004 – 2005 as that information does not have any relevance to the current UNS Gas rate case. Refer to the response to RUCO 11.11.a. for FERC proceedings UNS Gas has intervened in from the start of the test year to present. FERC proceedings UNS Gas intervened in from January 2006 – June 2007 include:

<u>El Paso Natural Gas Co.</u>

- RP04-19 - Filing of revised tariff sheets to FERC Gas Tariff for additional scheduling flexibility for EPNG shippers and proposing 5-tier scheduling mechanism
- RP04-110 - Revised tariff sheets to FERC Gas Tariff to establish procedures for re-designating primary rights under transportation service agreement; FERC Order issued 02/05/04 accepting procedures, subject to condition
- RP04-248 & RP04-251 - Revised tariff sheets to FERC Gas Tariff to implement new portfolio of Imbalance Management Services for shippers on its pipeline system in Docket RP04-248; filing of Proforma tariff sheets under FERC Gas Tariff in compliance with FERC Order Nos. 637, 637-A and 637-B in Docket RP04-251 with request that matter be consolidated with Docket RP04-248; offer of settlement filed with FERC 09/13/04
- CP04-368 - Application for authorization to abandon, by removal, its 7.1 miles 10¾-inch diameter Nevada Loop Line No. 2112 and replace segments of its 16-inch diameter Nevada Loop Line No. 2121, totaling 17.2 miles, located in Mohave County, AZ

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

- RP05-422 - General rate case under Section 4 of the FERC Rules and Regulations; 07/12/05 UNS Gas filed Protest, Request for Maximum Suspension, Request for Summary Rejections of Primary and First Alternative Cases, Request for Evidentiary Hearing and Motion to Intervene
- RP-06-102 - Revised tariff sheets to FERC Gas Tariff to revise certain bid evaluation options available for capacity release transactions to provide for multi-month releases with varying monthly contract quantities
- RP06-162 - Non-conforming Critical Meter Limit Agreement
- CP06-57 - Application for certificate of public convenience and necessity authorizing EPNG to acquire, own and operate 24" O.D. lateral pipeline facilities, with appurtenances, located in Pinal and Maricopa Counties, AZ from SRP
- CP06-69 - Petition for Exemption of Temporary Acts and Operations from Certificate Requirements seeking approval of exemption from certificate requires to perform temporary activities related to drilling test well and performing other activities to assess feasibility of developing underground natural gas storage facility in Pinal County, AZ
- RP06-310 - Tariff sheets to FERC Gas Tariff to add rates for service to Blythe, CA
- RP06-354 – East Valley Lateral Compliance Tariff Sheets
- RP06-369 - Revised tariff sheet to FERC Gas Tariff and Rate Schedule OPAS agreement with SRP
- RP06-372 - Revised tariff sheets to FERC Gas Tariff and 4 firm TSAs with APS and UNS Gas
- RP06-374 - Revised tariff sheet to FERC Gas Tariff and 7 firm TSAs with SRP
- RP06-418 - Revised tariff sheets to FERC Gas Tariff and 5 firm TSAs with AEPCO, UNS Gas and Aera Energy
- RP-06-600 - Revised tariff sheet to FERC Gas Tariff and 4 firm TSAs with Texas Gas Service Co.
- RP06-609 - Revised tariff sheets to FERC Gas Tariff to update discount provisions to incorporate most up-to-date list of permissible generic discounts
- RP06-615 - Revised tariff sheets to FERC Gas Tariff and 3 firm TSAs with PNM
- CP07-9 - Application for permission and approval to abandon, by sale to Transwestern, an undivided ownership interest in East Valley Lateral pipeline facilities located in Pinal and Maricopa Counties, AZ

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

- RP07-108 - Request to waive and/or reduce certain penalties and charges under FERC Gas Tariff for time period of 11/30/30-12/3/06
- RP07-144 - 9 Rate Schedule FT-1 TSAs containing revised exhibits with UNS Gas, APS and PNM
- RP07-152 - Revised tariff sheet to FERC Gas Tariff, Rate Schedule FT-1 TSA, 2 Rate Schedule FT-H TSAs and 1 Rate Schedule OPAS agreement all with SRP
- RP07-354 - Revised tariff sheets to FERC Gas Tariff to update exhibits to Form of Service Agreements applicable to service under EPNG's firm and operator rate schedules to match its current contracting practices
- RP07-390 - Revised tariff sheets to FERC Gas Tariff re TSAs

Transwestern Pipeline

- RP05-689 - Operating Balance Agreement (OBA) that contains a provision that is supplemental to the form of OBA set forth in and in accordance with FERC Gas Tariff
- RP05-695 - Revised tariff sheet to FERC Gas Tariff to set forth the factors and calculations used in determining the adjustments to and to revise settlement base rates to be effective 11/01/05
- RP05-696 - Revised tariff sheet to FERC Gas Tariff to set forth the new TCR II reservation surcharges to be effective 11/01/05
- RP06-604 - Revised tariff sheets to FERC Gas Tariff to remove outdated tariff provisions, update tariff information and terminology, clarify certain tariff provisions and conform to FERC policy, reorganize rate sheets, Rate Schedules and capacity release provisions and make minor clarifications and corrections to Tariff
- RP06-611 - Revised tariff sheets to FERC Gas Tariff to remove the TCR II Surcharge
- RP06-612 - Revised tariff sheet to FERC Gas Tariff to revise Settlement Base Rates in accordance with Transwestern's Stipulation and Agreement filed on 05/02/95 in Dkt. RP95-271, as amended
- RP06-614 – Rate increase application
- CP06-459 - Application seeking authority to construct and operate (i) appx. 25 miles of 36" diameter pipeline loop in 2 segments on existing San Juan Lateral in San Juan and McKinley Counties, NM, (ii) new 259-mile pipeline consisting of 36" and 42" diameter pipe extending southward from existing mainline near Ash Fork in Yavapai County, AZ through Coconino and Maricopa Counties, AZ and terminating at beginning of EPNG East Valley Lateral near City of Coolidge, AZ and (iii) customer laterals, meter stations and ancillary facilities ("Phoenix Pipeline Project")

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

b. The cost of UNS Gas' participation in each individual FERC case is not tracked on an individual case basis.

c. The outside legal cost of UNS Gas' participation in each individual FERC case is not tracked on an individual case basis.

d. All comments, testimony, etc. filed by UNS Gas in any of the FERC dockets in response to RUCO 11.11.a. or RUCO 11.12.a. above are publicly available data and can be viewed on the FERC website under Docket No. RP08-426. The link to the FERC website is: http://www.ferc.gov/. All non-public material is subject to attorney-client privilege. UNS Gas objects to disclosing any analysis or documents in closed or current FERC proceedings as doing so could disadvantage the Company in its litigation and/or settlement of open proceedings or future proceedings.

e. UNS Gas does not have any analysis on the impact of its participation in any of the FERC proceedings referenced in RUCO 11.11.a. nor in the FERC proceedings referenced in response to RUCO 11.12.a. above. It is impossible to determine the impact of one individual company's participation in a case whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

f. UNS Gas objects to disclosing any analysis or documents in closed or current FERC proceedings as doing so could disadvantage the company in its litigation and/or settlement of open proceedings or future proceedings. Additionally, all non-public material is subject to attorney client-privilege.

g. UNS Gas does not do an evaluation in advance of how much legal expense it should incur on each FERC proceeding in which it participates as it is impossible to know whether proceedings will be settled or fully litigated, and how long or complex these proceedings will be.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.13 Refer to Mr. Hutchens' rebuttal testimony at page 2. Provide complete supporting calculations, work papers and Excel files for the $9 million and $5.4 million amounts mentioned on page 2, line 16.

RESPONSE: Please see workpapers provided in response to RUCO 10.1.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes, Dave Hutchens

UNS GAS, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2008

	UNSG As Filed 11/7/08	ACC As Filed 6/8/09	ACC Difference		RUCO As Filed 6/8/09	RUCO Difference		UNSG Revised 7/8/09
Rate Case Revenue Annualization	1,448,476	1,797,514	349,038		1,448,476			1,448,476
Customer Annualization	(516,003)	655,768	1,171,771		-	516,003		(516,003)
Weather Normalization	(882,453)	(903,889)	(21,436)		(882,453)	-		(882,453)
Normalize Outside Legal Expense	305,984	-	305,984		88,310	217,674		305,984
Bad Debt Expense	63,211	(123,416)	186,627		63,211			63,211
Adjusted Operating Income	$11,600,004	$13,544,256			$13,090,781			$11,693,460
Operating Income Deficiency	$4,350,643	$1,164,915			$490,494			$4,439,710
Fair Value Addition (Pre-Tax)	$1,442,389	$912,685			$23,382			$1,353,322
Fair Value Operating Income Deficiency	$5,793,032	$2,077,600			$513,876			$5,793,032
Gross Revenue Conversion Factor	1.6366	1.6343			1.6366			1.6366
Increase in Gross Revenue Requirement	$9,480,876	$3,395,423			$841,000			$9,480,876
			ACC			RUCO		
Additional Exp And Rev if changed to Commission Precedent $ for $ changes			1,991,984			733,677		
Fair Value Difference			3,620,000	a		3,808,000	b	
Additional Revenue to be added to their filing if they followed precedent			5,611,984			4,541,677		
What their increases would have been had they followed precedent on the above items			$ 9,007,407			$ 5,382,677		
Note a: From Kent Grant's testimony								
Note b: $4.7M (Smith's testimony) less $841K								

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RUCO 11.18 Refer to Mr. Hutchens' rebuttal testimony at page 7, concerning the overall slumping economy.

a. Identify, quantify and explain all steps taken by UNSG in 2008 and 2009 to reduce costs.

b. For each cost reduction effort undertaken by UNSG identified in response to part a, please identify exactly where, and in what amount, each such cost reduction effort has been reflected in UNSG's determination of the Company's requested revenue increase.

RESPONSE: a. See summary of savings realized below:

UNG UNS Gas, Inc

	Jul 07 thru Jun 08	Jul 08 thru Jun 09	Associated reduction:	
A10 Labor Costs	10,929,439	10,889,945	(39,494)	Reduced Overtime, reduced FTEs
158 Supplemental Service	155,874	28,208	(127,665)	Meter reading brought in-house
162 Repairs & Maintenance	263,896	249,701	(14,196)	Reduced vehicle maintenance
A59 Training & Travel	283,462	263,265	(20,197)	Company reduction focus
406 Communications	758,366	535,060	(223,305)	Contract re-negotiation
B64 Transportation	652,670	454,440	(198,230)	Vehicle depreciation reduction

b. These savings are not reflected in the test year. Other increases as reflected within the overall operating cost are still higher than test year and will be in 2009 and 2010. The Company's cost savings efforts have only resulted in mitigating the increases and the effect of regulatory lag.

RESPONDENT: Paul Coleman

WITNESS: David Hutchens

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RUCO 11.19 Refer to Mr. Hutchens' rebuttal testimony at pages 12- 13, lines 1-3.

a. Referring to page 13, lines 1-3, please identify all expenses, by account, in the test year for payment of fees by UNSG for payments made at check cashing centers and/or other outside payment locations.
   i. Identify, quantify and explain fully how the discontinuance of the payment of such fees would impact expense on a going-forward basis.

b. Refer to page 12, please identify the test year expense for payments and/or fees paid to Circle K for Circle K's acceptance of customer utility bill payments.
   i. Identify, quantify and explain fully how the discontinuance of the payment of such fees would impact expense on a going-forward basis.

c. Referring to page 12, identify, quantify and explain the anticipated annual cost reductions to UNSG from having Walmart accept customer payments.

RESPONSE:

a. ACE America's Cash Express - $25,002.08
Other Outside Payment Locations* - $18,770.92

   i. As of July 1, 2009, UNS Gas will no longer incur expenses for payments made at any ACE (America's Cash Express) locations.

   Effective October 9, 2009, UNS Gas will incur a cost of 1.5 cents per payment made at the Other Outside Payment Locations. The cost is charged by the processing company, FISERV, for electronic delivery of payments. Due to an anticipated decline in volume of payments taken by Other Outside Locations, annual expenses are projected at less than $300.

b. $0. The ability of Circle K to accept UNS Gas payments never materialized.

   i. Not applicable.

c. UNS Gas incurs a 1.5 cent cost per payment made at a Walmart location. The cost is charged by the processing company, FISERV, for electronic delivery of payments. The anticipated annual cost reduction using Walmart is approximately $42,000. All costs are based on assumptions. Actual costs will be dependent on customer behavior.

*OA Quick Cash (Flagstaff); Radio Shack (Show Low & Lakeside);IGA Food & Drug (Sedona)

RESPONDENT: Lindy Sheehey

WITNESS: David Hutchens

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

RUCO 11.21 Refer to Ms. Kissinger's rebuttal testimony at pages 2-3. Identify the beginning and end-of-test year accrued liability amounts on UNSG's books for each of the following items:

a. Accrued vacation
b. Accrued pension liability
c. Accrued stock based compensation liability

RESPONSE: a.-c. Please see the table below.

	7/1/2007	6/30/2008
a. Accrued vacation	$389,233	$438,776
b. Accrued Pension	$2,625,165	$1,732,676
c. Accrued Stock Based Compensation Liability	$0	$0

RESPONDENT: Georgia Hale

WITNESS: Karen Kissinger

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RUCO 11.24 Refer to Ms. Kissinger's rebuttal testimony at page 3. Please admit that the "Commission approved method" of addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide based on the facts and evidence in that case. If your response is anything other than an unqualified admission, explain fully and provide all support relied upon.

RESPONSE: The Commission's method in addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide the case based on the facts and evidence in that case.

The Commission's method is to consider the facts and evidence in light of its past practices and treatment of specific items in other cases with the same facts and evidence. By so doing, the Commission provides consistency of treatment among the ratepayers of Arizona.

RESPONDENT: Gail Boswell

WITNESS: Karen G. Kissinger

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.25 Refer to Ms. Kissinger's rebuttal testimony at page 3. Please identify each and every Commission Decision and the specific language within each such decision which Ms. Kissinger believes provides a clear statement of the "accepted Commission approved methods" for evaluating a utility's ADIT balance for inclusion in, or exclusion from, rate base.

RESPONSE: In the cases referenced on page 3 of the Rebuttal Testimony, there were no challenges of the inclusion of these items in rate base. Therefore, there was no need for the Commission to explicitly discuss these items in its Decisions.

RESPONDENT: Gail Boswell

WITNESS: Karen G. Kissinger

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.26 Please provide all details of UNSG's lead-lag study in the current case which address how UNSG measured the cash payment lag associated with each of the following items:

a. Accrued vacation
b. Accrued pension liability
c. Accrued stock based compensation liability

RESPONSE:

a. UNS Gas did not make any specific adjustments in the lead-lag study for Accrued vacation.

b. UNS Gas Pension and Benefit payment lag reflects the payment lag for cash payments made to the pension funds trustees.

c. UNS Gas had no accrued stock based compensation liability.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.27 Refer to Mr. Dukes' rebuttal testimony at page 2.

a. Admit that UNSG provided no supporting calculations with its rebuttal testimony for its new over 2000% increase in its claim for cash working capital ($97,967 to $2,183,948). If your response is anything but an unqualified admission, explain fully.
b. Provide complete documentation including all Excel files and supporting calculations showing each payment relating to gas cost purchases from 1/1/2008 through the present.
c. Provide a copy of each gas purchase invoice from 1/1/2008 through the present.
d. Provide all payment documentation for each gas cost invoice from 1/1/2008 through the present.
e. Provide a copy of the current and prior gas purchase contracts and all amendments thereto affecting payment terms.
f. Identify the "primary purchased gas vendor" referred to on page 2, line 7.
g. When did the "primary purchased gas vendor" change its payment terms?
h. Provide all documents relating to the change in gas purchase payment terms including but not limited to all correspondence, letters, legal documents, tariff filings, invoices, emails.
i. Identify all credit limitations, referenced at page 2, line 10.
j. Provide all correspondence relating to all such credit limitations.
k. Explain in detail what UNSG could do to address each such "credit limitation"?
l. Identify, and provide a copy of, the specific provisions in the contract or agreement with the "primary purchased gas vendor" that allowed the vendor to change the payment terms.
m. Did UNSG contest or object to the change in payment terms? If not, explain fully why not. If so, provide all documents showing that UNSG objected to the change in payment terms.
n. Identify the payment terms that are related to each gas vendor that could provide gas supply to UNSG.
o. Identify all conditions that would allow UNSG to pay for purchased gas from the "primary purchased gas vendor" on a monthly basis.

RESPONSE:

a. UNS Gas provided supporting workpapers and calculations.

b. This information was provided with workpapers in UNS Gas' response to RUCO 10.1.

c. Please see RUCO 11.27(c & d), Bates Nos. UNSG(0571)09887 to UNSG(0571)10033, on the enclosed CD for the gas purchase invoices and payment documentation for the period 1/1/2008 through the present. This file contains gas purchase invoices for BP Energy, Transwestern Pipeline and EPNG. The file also includes a summary of each vendor's invoices (with payment detail). Mr. Dukes' Rebuttal Testimony included a revision of payment lag days for gas purchases. The revised payment lag days calculation included BP Energy invoices for 12/1/08 through 5/16/09 because the payment timing to this vendor **changed** from thirty (30) days to every two (2) weeks. The revised payment lag days calculation did not include additional invoices for Transwestern Pipeline or EPNG because the payment timing to those vendors did not change; however attached file includes invoices for Transwestern Pipeline and EPNG for your review, in addition to BP Energy invoices used in the payment lag days calculation revised for Mr. Dukes' rebuttal testimony. Invoices for the vendors included in the lead-lag study as originally filed are identified by Bates Nos. UNSG0571/01980 through UNSG0571/02063.

d. Please see UNS Gas' response to RUCO 11.27.c. above.

e. Current gas purchase contract: Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated September 1, 2008.

First Amendment to Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated November 18, 2008.

Prior gas purchase contract: Natural Gas Supply and Transmission Management Agreement by and between Citizens Communications Company, Arizona Gas Division and BP Energy Company, dated October 28, 2002, but effective as of October 1, 2002.

Pleas see RUCO 11.27(e), Bates Nos. UNSG(0571)10034 to UNSG(0571)10135, on the enclosed CD.

f. British Petrolium Energy Company.

g. January 2008 – March 2008, and November 2008 – May 2009.

h. Please see RUCO 11.27(h) (Confidential), Bates Nos. UNSG(0571)10138 to UNSG(0571)10144, on the enclosed CD.

For the winter season 2007/2008, see emails and the Standby Letter of Credit dated December 28, 2007.

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For the winter season 2008/2009, see emails, Amendment to Base Contract dated November 18, 2008, and the Standby Letter of Credit dated October 30, 2008.

i. UNS Gas' primary purchased gas vendor (BP Energy) provides UNS Gas with an unsecured credit limit based upon its assessment of UNS Gas' creditworthiness. If the vendor's total exposure to UNS Gas exceeds that credit limit, it may decline to enter into additional transactions with UNS Gas until the exposure is below the credit limit, or it may request some form of performance assurance to cover the amount of the credit exposure in excess of the credit limit or to cover proposed new business. Such performance assurance may be in the form of a prepayment, a standby letter of credit, a performance bond, or a guaranty by another party.

Because UNS Gas is a winter-peaking gas distribution company, its exposure to its primary gas supplier is highest during the winter months of November through April. In each of the last two years, UNS Gas' exposure to BP Energy exceeded its credit limit. Therefore, UNS Gas negotiated terms to provide credit support in the form of more frequent payments (twice monthly) and a standby letter of credit, so that UNS Gas could continue to enter into new transactions with BP Energy.

j. Please see UNS Gas' response to RUCO 11.27.h above.

k. UNS Gas could make more frequent payments of amounts owed for gas supplied, could provide a standby letter of credit from a financial institution, or could curtail doing new business with the supplier, or a combination of these actions. The decision to provide a letter of credit vs. make prepayments depends on several factors including available credit under its revolving credit facility to issue letters of credit, the cost of issuing letters of credit, the amount of available cash on hand, and the interest rate that could be earned on the investment of excess cash.

l. Please see RUCO 11.27(e), UNSG(0571)10034 to UNSG(0571)10135,on the enclosed CD, and refer to Article IV—Security, of the Natural Gas Supply and Transportation Management Agreement dated October 28, 2002, and to Section 10.1—Financial Responsibility of the Base Contract dated September 1, 2008.

m. No, UNS Gas did not object to the change in payment terms. The vendor's request was reasonable in view of the size of the credit exposure compared to the credit limit provided, and therefore UNS Gas was willing to negotiate terms with the supplier that were agreeable to both parties.

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n. Please see UNS Gas' response to Staff's first set of data requests, JMK 1-1, in which all lead-lag workpapers were provided.

o. As long as the vendor's total exposure to UNS Gas is within the credit limit established for UNS Gas, UNS Gas may pay for purchased gas on a monthly basis.

RESPONDENT: Barbara McCormick, Dallas Dukes, Janet Zaidenberg-Schrum (parts c and d)

WITNESS: Dallas Dukes, Kentton C. Grant

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RUCO 11.28 Refer to Mr. Dukes' rebuttal testimony at page 4-5.

a. Please admit that replacement of old mains and services could reduce maintenance costs. If your response is anything but an unqualified admission, explain fully.

b. Please admit that additional transportation equipment could serve customer growth. If your response is anything but an unqualified admission, explain fully.

c. Please admit that replacing old transportation equipment with new equipment could reduce maintenance costs. If your response is anything but an unqualified admission, explain fully.

d. Please admit that all "post test year plant" that UNSG is requesting in rate base was in CWIP as of the end of the test year. If your response is anything but an unqualified admission, explain fully.

e. Please admit that all of the decisions cited on page 4, line 18, pertain to water utilities. If your response is anything but an unqualified admission, explain fully.

f. Please admit that UNSG is not a water utility. If your response is anything but an unqualified admission, explain fully.

g. Please admit that UNSG has not cited in its rebuttal testimony any decisions allowing post test year plant for energy utilities. If your response is anything but an unqualified admission, explain fully.

h. Please admit that other Commission decisions that were <u>not</u> cited in UNSG's rebuttal testimony have denied rate base inclusion of post test year plant. . If your response is anything but an unqualified admission, explain fully.

i. Please identify each Commission decision from 2004 through the present that addressed whether post test year plant should be included in rate base of which UNSG and its witnesses and counsel are aware.

RESPONSE:

a. Yes it could.

b. All transportation equipment is purchased to be used in providing natural gas service to existing customers and any new customers.

c. Yes it could.

d. Yes it was.

e. Yes they do.

f. UNS Gas is not a water company.

g. UNS Gas has not.

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h. The Commission has denied the inclusion of post test year plant in rate base in other decisions.

i. UNS Gas has not conducted an exhaustive survey of all Commission rate case decisions since 2004. However, several decisions have allowed post-test year plant in rate base, including:

- Rio Rico Utilities, Inc, Decision No. 67279 (October 5, 2004);
- Arizona Water Company, Decision No. 66849 (March 19, 2004);
- Bella Vista Water Company, Inc., Decision No. 65350 (November 1, 2002);
- Arizona-American Water Company, Decision No. 68864 (July 28, 2006); and
- Chaparral City Water Company, Decision No. 68176 (Sept. 30, 2005).

Moreover, in the prior UNS Gas rate case, the Commission noted in Decision No. 70011, page 8, that the Commission has allowed post-test year plant in rate base where there was an assurance that a mismatch of revenues did not occur, such as when the plant is revenue-neutral-- which is the case here.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

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RUCO 11.30 Refer to Mr. Dukes' rebuttal testimony at page 5, lines 5-7.

a. Identify the name and job title of each person who reviewed the CWIP projects and indicate whether they are a witness for UNSG gas in the current rate case.

b. Provide all written criteria that were considered by the people identified in response to part a, to evaluate whether an item of end of test year CWIP would produce additional revenue or not.

c. How did the Company determine that none of the service and main replacements would serve any new customers? Explain fully and provide all supporting analysis.

d. Does UNSG have any analysis to support its claim for post test year plant other than what was provided in UNSG workpapers UNSG 0571 / 03012 through 03015? If not, explain fully why not. If so, please identify and provide all additional support that UNSG has.

RESPONSE:

a. Carl Dabelstein, Manager of Plant Accounting TEP – not a witness

Diane Grant, Lead Plant Accountant TEP – not a witness

Paul Coleman, Director of Business Services UES – not a witness

Paula Smith, Operations Support Analyst UNS Gas – not a witness

Gary Smith, General Manager UNS Gas – retired employee/prior witness

Dallas J. Dukes, Manager Pricing and Economic Forecasting TEP – witness

b. Instructions were given verbally to identify "non-additional" revenue producing plant that had been invested in prior to the end of the test year that was not being installed for the purpose of meeting customer growth, was not being installed to serve new customers and investments that would have been made whether we added additional customers or not.

c. Replacements were identified whose primary purposes were to serve existing customers and would have been replaced regardless of potential customer additions.

d. Please see UNS Gas' response to RUCO 1.88.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

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RUCO 11.32 Refer to Mr. Dukes' rebuttal testimony at page 5.

a. Admit that UNSG's proposal to fail to offset rate base by the full amount of Customer Advances is simply inconsistent with prior Commission decisions, including, but not limited to, Decision No. 70011 in UNSG's last rate case. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

b. Admit that when UNSG receives a Customer Advance in the form of money, it has the use of that non-investor supplied money. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

c. Admit that Customer Advances are a non-investor supplied source of cost-free capital to the Company. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

d. Admit that UNSG does not reduce the CWIP base to which it applies an AFUDC rate by the amount of Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

e. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

f. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base, without any exception for Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

g. Admit that Customer Advances are non-investor supplied capital when they are received by the utility. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

h. Admit that UNSG does not hold Customer Advances in an escrow account. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

i. Admit that it would be inappropriate for a utility to earn a return on non-investor supplied capital. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

RESPONSE:

a. UNS Gas does not believe that it is inconsistent, as UNS Gas is requesting only the exclusion of the portion of advances already spent as of the end of the test year on plant not included in rate base. The Company is arguing that the portion already spent is not available as zero cost capital as of the end of the test year, and since the plant it was spent upon is not in rate base, it is unfair to the Company to reduce rate base.

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b. Yes. UNS Gas has the use until it is invested in the projects it was specifically advanced to fund. UNS Gas has not attempted to exclude any portion of customer advances not yet spent or spent on plant included in rate base.

c. Please see UNS Gas' response to 11.32.b. above.

d. UNS Gas does not reduce CWIP by advances prior to calculating AFUDC.

e. The only suggestion in Rule 103 that Customer Advances should be deducted from rate base is a line in the form schedule B-1. However, that schedule does not expressly address the circumstance where the advance is related to plant that is not yet in rate base. This rule only controls the general filing format of the rate application, not the final ratemaking decision by the Commission. (See e.g. Decision No. 69914 (Sept. 27, 2007) approving non-deduction of certain advances from rate base.) The rule does not -- and should not -- preclude the Commission from exercising judgment and fairness to insure proper matching and equitable treatment of the shareholders' capital investments. Deducting advances from rate base when the advance is related to plant that is not yet in rate base results in a mismatch and is inequitable because the Company is unable to earn a return on all of its investment in plant that is in rate base.

f. Please see UNS Gas' response to 11.32.e. above.

g. Please see UNS Gas' response to 11.32.b. above.

h. UNS Gas does not hold customer advances received in an escrow account.

i. UNS Gas is not requesting any returns on non-investor supplied capital in this proceeding. As the customer advance reduction in rate base is being interpreted by Staff and RUCO – the Company is being unfairly denied a return on investor supplied capital in rate base.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

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RUCO 11.36 Refer to Mr. Dukes' rebuttal testimony at page 29-30.

a. Provide the documents relied upon by Mr. Dukes for each amount mentioned on page 29.

b. Provide all vehicle fuel price invoices UNSG has for the months of January through June 2009.

c. Provide the fuel price invoices UNSG has for the month of July 2009.

d. Would the Company's actual invoices for fuel over a recent period be an appropriate reflection of the current known price levels? If not, explain fully why not.

e. Refer to page 30, line 26. Please identify the specific period constituting "the past three years".

f. Does UNSG have information from which an average fuel price for the 36-month period ("last three years") ending June 30, 2009 could be computed? If not, explain fully why not. If so, please provide that information.

g. What fuel prices has UNSG used in its 2009 operating expense budget? Provide the related documentation.

h. What fuel prices has UNSG used in its 2009, 2010 and 2011 budgets and/or forecasts? Provide the related documentation.

RESPONSE:

a. Mr. Dukes reviewed the fuel prices on the websites noted on page 29 of his Rebuttal Testimony, but did not retain screen prints of the prices.

b. Please see RUCO 11.36(b & c), Bates Nos. UNSG(0571)10197 to UNSG(0571)10234 on the enclosed CD for the requested information.

c. Please see UNS Gas' response to RUCO 11.36.b above.

d. Using recent prices is one method of arriving at a price per gallon for fleet fuel. However, as noted in Mr. Dukes' Rebuttal Testimony on page 30, the significant and continued volatility of the cost of fuel per gallon is better addressed by using a longer period of actual information.

e. The period constituting "the past three years" refers to calendar years 2006, 2007 and 2008. This information was included in the backup to Mr. Dukes' Rebuttal Testimony in response to RUCO Data Request 10.1 as Excel file "RUCO 10.1 – Income – Fleet Fuel Expense".

f. Yes. Please see the Excel file RUCO 11.36(f) on the enclosed CD for the average fuel price for the 36 months ending June 30, 2009.

g. Please see the PDF file RUCO 11.36(g-h), Bates No. UNSG(0571)10235 on the enclosed CD for the requested information.

h. Please see UNS Gas' response to RUCO 11.36.g above.

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The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Dallas Dukes, Gary Kelly, Julie Gomez & Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS GAS, INC.
FLEET FUEL EXPENSE - RUCO 11.36f
36 MONTH AVERAGE FUEL PRICE
July 2006 through June 2009

Calculated using revised data from J. Gomez 6/26/09 & 7/16/09

	Cost per Gallon
Jul-06	$3.01
Aug-06	$2.98
Sep-06	$2.67
Oct-06	$2.46
Nov-06	$2.47
Dec-06	$2.51
Jan-07	$2.43
Feb-07	$2.48
Mar-07	$2.74
Apr-07	$2.99
May-07	$3.09
Jun-07	$3.07
Jul-07	$3.00
Aug-07	$2.85
Sep-07	$2.85
Oct-07	$3.00
Nov-07	$3.26
Dec-07	$3.23
Jan-08	$3.17
Feb-08	$3.26
Mar-08	$3.58
Apr-08	$3.73
May-08	$4.05
Jun-08	$4.35
Jul-08	$4.32
Aug-08	$3.97
Sep-08	$3.78
Oct-08	$3.24
Nov-08	$2.50
Dec-08	$2.04
Jan-09	$2.12
Feb-09	$2.20
Mar-09	$2.12
Apr-09	$2.32
May-09	$2.28
Jun-09	$2.62
Average	**$2.96**

7/24/2009 1:02 PM

Zaidenberg-Schrum, Janet

From:	Kelly, Gary
Sent:	Thursday, July 16, 2009 2:20 PM
To:	Zaidenberg-Schrum, Janet
Subject:	UNSG Rate Case - RUCO 11.36g & h

From:	Kelly, Gary
Sent:	Thursday, July 16, 2009 1:38 PM
To:	Zaidenberg-Schrum, Janet
Cc:	Gomez, Julie; Cordero, Jessica
Subject:	RE: UNSG Rate Case - RUCO Data Request for Fleet Fuel

Below is the information that you requested.

The budgeted price for fuel in 2009 was $4.05 per gallon based on approximately 207,000 gallons used annually

The figures listed below have been submitted for the 2010 and 2011 budget

2010 - $2.75 per gallon, 207,000 gallons used annually. Total budgeted amount $569,250
2011 - $2.95 per gallon, 207,000 gallons used annually. Total budgeted amount $610,650

The numbers listed above include gasoline and diesel.

Please let me know if you need additional information.
GK

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

RUCO 11.38 Refer to Mr. Grant's rebuttal testimony at page 24.

a. Provide complete supporting documentation for each amount shown in the table, including a detailed identification and explanation for all assumptions used in the projections.

b. Provide a detailed listing of all items in the "Operating Expenses" line of the table, including but not limited to the following:
   i. SERP
   ii. Incentive compensation expense
   iii. Stock-based compensation expense
   iv. Outside legal expense
   v. Rate case expense

c. Identify the amount of common equity in the table for each year that is not supporting Arizona adjusted jurisdictional original cost rate base.

d. Identify all assumptions, and provide all calculations, related to the amount of interest expense in the table. For each year, provide a listing of all debt issuances outstanding, the interest rate for each (including how it was calculated) and the amount of interest. Also show how the interest expense was allocated between (1) debt supporting AZ jurisdictional rate base and (2) debt supporting other items on UNSG's balance sheet that are not included in rate base.

e. What income tax rate did UNSG use to compute the Income Tax Expense for each year in the table? Provide supporting calculations. If an income tax rate that is different than the rate proposed by UNSG in the rate case was used, provide a complete reconciliation. Identify, quantify and explain each reconciling item fully.

f. Please identify fully and in detail how UNSG has reflected 2008 and 2009 bonus tax depreciation in its 2008 actual results and 2009 projections. Include complete supporting calculations.

RESPONSE:

a. The referenced table on page 24 of Mr. Grant's Rebuttal Testimony is based on the 2008 financial statements for UNS Gas and a financial forecast for the period 2009-2011 that were included in the workpapers to Mr. Grant's Rebuttal Testimony and previously provided in response to data request RUCO 10.1. For 2008 values, please refer to the 2008 income statement for UNS Gas provided in Mr. Grant's Rebuttal workpapers. For 2009-2011 values, please refer to the financial forecast provided in Mr. Grant's Rebuttal workpapers. Specifically, please refer to the forecast page with the heading "UNSG – Income Statement." There are 12 columns of data on that page, the first four of which reflect the forecast presented in Mr. Grant's Direct Testimony, the middle four of which reflect the financial forecast presented in Mr. Grant's Rebuttal Testimony, and the final four of which reflect the difference between these two forecasts. It is

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the middle four columns of data on this page that were used to populate the table on page 24 of Mr. Grant's Rebuttal Testimony. A line-by-line explanation of the values appearing on the referenced table is presented below, along with references to the financial forecast in Mr. Grant's Rebuttal workpapers and other supporting information.

Gross Margin

Gross margin is equal to total revenues minus purchased gas expense. The calculation of gross margin, along with the various line items comprising total revenues and purchased gas expense, may be found in the forecasted income statement provided in Mr. Grant's Rebuttal workpapers. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts its gross margin to be $64,975,000.

Most of the Company's gross margin is derived from retail delivery revenues, which, along with demand-side management ("DSM") program revenues, are shown as "Retail T&D Revenues" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts retail delivery revenues of $56,927,000 and DSM program revenues of $1,044,000.

Delivery revenues from transport customers and long-term contract customers (the Griffith and Black Mountain generating stations) also contribute to gross margin. Delivery revenues from transport customers and the Griffith Power Plant are reflected as "Wholesale Transmission Revenues" on the Company's forecasted income statement. The $570,000 in annual delivery revenues from the Black Mountain Generating Station are lumped in with gas sales to UNS Electric in "Wholesale Energy Sales" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts total transport and long-term contract delivery revenues of $4,912,000.

Miscellaneous customer service charges, which include connect/disconnect fees, late payment fees, etc. also contribute to gross margin and are reflected as "Other Revenues" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts Other Revenues of $1,626,000.

Margins derived from sales of gas to transport customers under the Negotiated Sales Program ("NSP") also contribute to gross margin. Fifty percent of these margins are retained by the Company, while the other fifty percent are credited to the PGA balance. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts its share of NSP margins to be $466,000.

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This amount can be derived from the forecasted income statement in Mr. Grant's Rebuttal work papers by subtracting purchased gas expense (equal to "Purchased Power and Gas for Resale" plus "Deferred Fuel Expense") from purchased gas revenues (equal to "PPFAC/PGA Revenues" plus "Wholesale Energy Sales" minus $570,000 in Black Mountain delivery revenues included in "Wholesale Energy Sales").

In summary, for 2010, the first full year under new rates in the Company's financial forecast, the forecasted gross margin is as follows:

$56,927,000	Retail Delivery Revenues
1,044,000	DSM Program Revenues
4,912,000	Transport and Long-Term Contract Delivery Revenues
1,626,000	Other Revenues
466,000	NSP Margins
$64,975,000	Gross Margin

For 2011, the forecasted gross margin is as follows:

$57,983,000	Retail Delivery Revenues
1,076,000	DSM Program Revenues
4,912,000	Transport and Long-Term Contract Delivery Revenues
1,691,000	Other Revenues
437,000	NSP Margins
$66,099,000	Gross Margin

By comparison, the actual gross margin in 2008 was $55,424,000. The forecasted gross margin for 2009, which reflects three months of actual results, eight months of forecasted results under current rates, and one month of forecasted results under the Company's requested rates, is little changed at $55,532,000.

Based on a comparison of the 2008 actual gross margin to the forecasted 2010 gross margin, the Company is forecasting a total increase in gross margin of $9.6 million. Of this, $9.3 million is attributable to the requested rate increase, partially offset by a $0.2 million reduction in retail revenue related to a decline in sales.

The following tables provide additional detail on the Company's forecast of retail delivery revenues and transport customer delivery revenues. Additional detail supporting the Company's forecast of retail revenues is also being provided in the four Excel files named RUCO 11.38 UNS Gas_Non-Industrial Sales ACTMAR09 forecast.xls, RUCO 11.38 UNS Gas_Industrial Sales ACTMAR09 forecast.xls, RUCO 11.38 UNS Gas_Non-Industrial Revenue ACTMAR09 forecast.xls, and RUCO 11.38 UNS Gas_Industrial Revenue ACTMAR09 forecast.xls.

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

Retail Sales and Delivery Revenues

		2010		2011
Retail Sales (therms)				
Residential		71,248,000		73,491,000
Commercial		30,258,000		30,444,000
Industrial		1,780,000		1,780,000
Public Authority		6,654,000		6,633,000
Total Retail Sales		109,940,000		112,348,000
Average Delivery Rates ($/therm)				
Residential	$	0.603	$	0.598
Commercial	$	0.384	$	0.384
Industrial	$	0.170	$	0.170
Public Authority	$	0.310	$	0.310
Average Delivery Rates	$	0.518	$	0.518
Retail Delivery Revenues				
Residential	$	42,947,000	$	43,937,000
Commercial		11,615,000		11,688,000
Industrial		302,000		302,000
Public Authority		2,062,000		2,056,000
Total Retail Delivery Revenues	$	56,927,000	$	57,983,000

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Transport and Long-Term Contract Delivery Revenue

	2010	2011
Transport Sales and Delivery Revenues		
Transport Sales (therms)	40,748,000	40,893,000
Average Delivery Rates ($ / therm)	$ 0.085	$ 0.085
Transport Delivery Revenues	$ 3,477,000	$ 3,477,000
Total Long-Term Contract Delivery Revenues	$ 1,435,000	$ 1,435,000
Total Transport and Long-Term Contract Delivery Revenue	**$ 4,912,000**	**$ 4,912,000**

Operating Expenses

Total operating expenses represent the sum of (i) Operation and Maintenance Expenses, (ii) Depreciation Expense, (iii) Taxes Other than Income Taxes and (iv) Other Amortization Expense. Each of these line items may be found in the forecasted income statement in Mr. Grant's Rebuttal workpapers.

For 2009, which reflects three months of actual results and nine months of forecast information, the forecast amount for total operating expenses is as follows:

$26,798	Operations and Maintenance Expenses
7,286	Depreciation Expense
3,048	Taxes Other than Income Taxes
89	Other Amortization Expense
$40,592	Total Operating Expenses

For 2010, the first full year under new rates in the Company's financial forecast, the forecast amount for total operating expenses is as follows:

$29,422	Operations and Maintenance Expenses
7,717	Depreciation Expense
3,194	Taxes Other than Income Taxes
258	Other Amortization Expense
$40,592	Total Operating Expenses

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For 2011, the forecast amount for total operating expenses is as follows:

$30,765	Operations and Maintenance Expenses
8,135	Depreciation Expense
3,433	Taxes Other than Income Taxes
167	Other Amortization Expense
$42,499	Total Operating Expenses

The current year (2009) forecast of Operations and Maintenance ("O&M") Expense is based on the Company's 2009 operating budget, which is updated throughout the year for forecasting purposes with actual year-to-date spending and budget re-projections for the balance of the year. The long-term forecast of O&M expense is based on the approved 2009 budget escalated using a 4% annual escalation rate. The only components of O&M expense that are not subject to the annual escalation rate are DSM program costs and vehicle depreciation expense which are forecasted separately. The approved 2009 O&M budget is being provided in the Excel file named RUCO 11.38 UNS Gas 2009 Budget.xls. The following table shows the derivation of forecasted O&M expense for 2010 and 2011:

Operations and Maintenance $ in thousands	**Approved 2009 Budget**	**2010 Forecast**	**2011 Forecast**
General O&M	$18,802	$19,554	$20,336
SERP	113	118	122
Incentive Compensation Expense	664	691	718
Outside Legal Expense	256	266	277
Vehicle Depreciation	832	890	1,102
Bad Debt Expense	1,000	1,040	1,082
Intercompany Expenses	4,701	4,889	5,084
Pension Expense	896	931	969
DSM Program Expense	824	1,044	1,076
Total Operations and Maintenance Expenses	$28,087	$29,422	$30,765

Depreciation expense is forecasted based on the current balance of plant in service, forecasted additions and retirement to plant in service, applicable plant depreciation rates, and forecasted amortization of the acquisition adjustment arising from the Company's 2003 purchase of Citizen's gas distribution system.

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Detail supporting the Company's forecast of depreciation expense is being provided in the Excel file named RUCO 11.38 UNS Gas ACTMAR09 - depreciation expense and property taxes.xls.

Taxes Other than Income Taxes are forecasted based on the current balance of plant in service, forecasted additions and retirement to plant in service, applicable property tax rates, and a forecast of payroll taxes based on budgeted labor costs. Detail supporting the Company's forecast of property tax expense is being provided in the Excel file named RUCO 11.38 UNS Gas ACTMAR09 - depreciation expense and property taxes.xls.

Other Amortization Expense in the forecast is based on the Company's estimate of rate case expense recovery. For 2010, the Company has assumed amortization expense relating to both the current rate case and previous rate case. For 2011, the Company is forecasting expenses relating only to the current rate case.

Operating Income

Operating Income = Gross Margin – Total Operating Expenses.

Other Income – Net

Forecasted Other Income is comprised of interest on marketable securities and the allowance for equity funds used during construction. These two amounts are shown separately on the forecasted income statement included in Mr. Grant's Rebuttal workpapers. Interest on marketable securities is based on a forecast of the Company's cash balances and a forecast of short-term interest rates that can be earned on these balances. The forecasted short-term investment rate is based on the forward curve for LIBOR less 0.50%. For 2010 and 2011 the forecasted short-term investment rates are 0.74% and 1.79%, respectively. The forecasted allowance for equity funds used during construction is based on the forecasted balance of CWIP and the equity portion of the Company's AFUDC rate.

Interest Expense

Interest expense during the forecast period is comprised of (i) interest on the balance of long-term notes outstanding, (ii) amortization of issuance costs on the long-term notes outstanding, and (iii) commitment fees and letter of credit fees relating to the Company's bank credit facility. As may be seen in the forecasted income statement provided in Mr. Grant's Rebuttal workpapers, interest on the long-term notes is forecasted at $6,230,000 in 2010 and $6,472,000 in 2011. The amount for 2010 reflects the current interest rate of 6.23% on the Company's $100 million balance of long-term notes. A higher interest expense is forecasted in 2011 due to the anticipated refinancing of $50 million of maturing long-term notes with

$60 million of new long-term notes bearing the same interest rate. Other interest costs are forecasted to remain at approximately $100,000 per year. Since no short-term borrowing is forecast, no interest on short-term borrowing is forecast.

Pre-Tax Income

Pre-Tax Income = Operating Income + Other Income – Interest Expense

Income Tax Expense

Income tax expense is forecasted by applying a composite federal/state income tax rate of 39.615% to the Company's forecast of pre-tax income.

Net Income

Net income = Pre-Tax Income – Income Tax Expense

Ending Common Equity

Ending Common Equity = Previous Balance + Net Income – Dividends Paid

See the forecasted balance sheet in Mr. Grant's rebuttal workpapers for the ending common equity balances.

Return on Average Equity

ROE = Net Income / ((Beginning Common Equity + Ending Common Equity)/2)

ROE in 2008 = 9.2% = $8,538,000 / (($88,265,000 + $96,684,000)/2)

ROE in 2009 = 7.2% = $7,270,000 / (($96,684,000 + $103,948,000)/2)

ROE in 2010 = 10.1% = $11,013,000 / (($103,948,000 + $114,961,000)/2)

ROE in 2011 = 9.0% = $10,544,000 / (($114,961,000 + $120,233,000)/2)

b. Please see UNS Gas' response to RUCO 11.38.a. above for line items included in "Operating Expenses," the detailed line items included in the 2009 operating budget, and an explanation of how 2010 and 2011 O&M expenses are escalated from 2009 budget spending levels.

  i. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above.

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ii. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above. Incentive compensation expense and stock-based compensation expense are shown as one line item on this table.

iii. Please See Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above. Incentive compensation expense and stock-based compensation expense are shown as one line item on this table.

iv. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above.

v. See discussion of "Other Amortization Expense" provided in response to RUCO 11.38.a. above.

c. No such allocation of common equity has been performed. However, since only a small portion of the Company's plant in service is not included in rate base (i.e., plant serving the Griffith and Black Mountain generating stations), any allocation of common equity to non-rate base investment would be quite small.

d. Please see the response to RUCO 11.38.a. above for an explanation of forecasted interest expense. No allocation of forecasted interest expense between "AZ jurisdictional rate base" and "other items on UNSG's balance sheet" has been performed. However, since only a small portion of the Company's test-year plant in service is not included in rate base (e.g., plant serving the Griffith and Black Mountain generating stations), any allocation of interest expense to non-rate base investment would be quite small.

e. The combined effective tax rate used to compute the Income Tax Expense for the table was 39.615%. That effective tax rate was calculated using a state tax rate estimate of 7.1% and a federal tax rate estimate of 32.515%. The combined effective tax rate proposed by UNS Gas in the rate case was 38.598%. The 38.598% was calculated using a state tax rate of 6.968% and a federal tax rate of 31.630%.

The combined effective tax rate proposed in the rate case was calculated using a state tax rate specific to Arizona and the current federal rate. The combined effective tax rate used for the forecast table was a composite tax rate applicable to UniSource Energy Corporation ("UniSource"). If this higher composite tax rate applicable to UniSource had been used to calculate the revenue requirement for UNS Gas, the Company's requested revenue requirement would have been $192,000 higher.

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f. The amounts in the referenced table on page 24 of Mr. Grant's Rebuttal Testimony are not affected by bonus tax depreciation. While bonus tax depreciation does affect the current portion of the Company's income tax liability, it has no bearing on the accrual of income tax expense presented in the table on page 24 of Mr. Grant's Rebuttal Testimony.

RESPONDENT: Kentton C. Grant and Martha Pritz

WITNESS: Kentton C. Grant

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
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RUCO 11.40 Refer to Mr. Dukes' rebuttal testimony at page 9-10.

a. Provide all documentation relied upon by Mr. Dukes for the statement at page 10, lines 12-13: "At this time we know the increases attributable to the portion of the workforce that are classified and have contracts in place."
b. Provide the dollar amount of payroll expense increase that is related to "the portion of the workforce that are classified and have contracts in place." Include supporting calculations.
c. Is UNSG aware of any other businesses in Arizona that have reduced or curtailed scheduled wage increases because of the poor economic climate? If not, explain fully why not. If so, please explain fully UNSG's knowledge on this subject.
d. Is UNSG aware of any other utilities that have curtailed previously budgeted wage increases because of the poor economic climate? If not, explain fully why not. If so, please explain fully UNSG's knowledge on this subject.
e. Does UNSG agree that the economic climate in Arizona in mid-2009 is worse than in each of the last Southwest Gas filings? If not, explain fully why not.
f. Please identify the specific RUCO testimony and portions thereof in "each of the last three Southwest Gas filings" to which Mr. Dukes is referring on page 10, line 5.

RESPONSE:

a. Please see RUCO 11.40(a), Bates No. UNSG(0571)10238, on the enclosed CD.

b. The pro forma payroll adjustment for the classified employee increase in 2010 was based on an assumed 3% increase and is consistent with the supporting documentation provided in UNS Gas' response to RUCO 11.40.a. The amount of payroll expense adjustment attributable to the 2010 increase for classified employees is $129,654. The unclassified portion is $96,088.

c. UNS Gas has performed no study to identify the wage activity of other Arizona companies in the present economy.

d. UNS Gas has performed no study to identify the wage activity of other Arizona Utilities in the present economy.

e. Yes.

f. RUCO's position in those cases, including citation to the RUCO testimony, is set forth as follows: Decision No. 64172, page 10, lines 19-21; Decision

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No. 68487, page 12, lines 24-25; and Decision No. 70665, page 10, lines 6-10.

RESPONDENT: Regulatory Department

WITNESS: Dallas Dukes

Dukes, Dallas

From: Poturalski, Heidi
Sent: Tuesday, June 09, 2009 3:42 PM
To: Dukes, Dallas
Cc: Bracamonte, Steve
Subject: RE: UNS Gas Case

RUCO 11.40a

Hi Dallas. We just concluded negotiations with Local 1116 and they will receive a 2.25% increase on 6-24-09, and then a 2.75% increase on 1-4-2010, 1-3-2011 and 1-2-2012.

* The Local 387 contract expires before the next wage increases for 2010 so I don't have any data on those yet as we will start negotiations with them towards the end of the year.

The Local 769 contact does have wages for 2010 and they receive a 3.3% increase effective 1-4-10.

From: Dukes, Dallas
Sent: Tuesday, June 09, 2009 3:17 PM
To: Poturalski, Heidi
Cc: Bracamonte, Steve
Subject: UNS Gas Case
Importance: High

* = will be negotiated prior to year end, but will be in range with other two.
Dallas Dukes 6/9/09

Heidi, do you have information for anything for 2010? Specifically, have we got any contracts for the classified groups that have already approved 2010 wage increases?

Thanks!

RUCO 1.56 Wage Rate Increases. Refer to page 19 of Dallas Dukes' testimony. Please provide the wage rate increases granted by the Company by date and employee category for 2007, 2008 and 2009.

RESPONSE: Please see UNS Gas' response to TF 6.94 in Staff's sixth set of data requests. An expansion of the response to include dates and to update the response with 2009 information is provided below:

The budgeted and actual merit increases for employees represented by Local 1116 in 2007 was 3% effective 1-8-07, in 2008 was 3% effective 1-7-08 and in 2009 was 1.5% effective 1-5-09.

The budgeted and actual merit increases for employees represented by Local 387 in 2007 was 3% effective 3-1-07, in 2008 was 3.5% effective 3-1-08 and 2009 was 3.5% effective 3-1-09.

The budgeted and average merit increases for non-represented employees for 2007

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RUCO 11.46 Refer to Mr. Dukes' rebuttal testimony at page 31. Please provide the specific adjustment, and all related supporting calculations, that UNSG believes would be necessary to "correct" the Staff postage adjustment to reflect the correct annualized number of customers. Include all related Excel files and supporting workpapers.

RESPONSE: Please see the Excel file RUCO 11.46 on the enclosed CD for the original Staff and revised postage expense adjustment as requested.

The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

AS REVISED BY UNSG PER DUKES REBUTTAL TESTIMONY (PAGE 31) & PER ACC STAFF RESPONSE TO UNSG DATA REQUEST 2.15

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills - Unadjusted		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Unadjusted customers	$	34,782	Line 1 * Line 2
4	UNSG Customer Annualization (difference between actual & adjusted customers on an annual basis per Bentley Erdwurm rebuttal testimony)		(4,139)	UNSG Schedule H2 P1
5	Staff Customer Annualization Postage	$	(1,821)	Line 4 * .44
6	Postage Expense Adjustment - Increase Expense	$	32,960	Line 3 + Line 5
7	Less: UNSG Postage Expense Adjustment As Filed (Bates Nos. UNSG0571/02494 & UNSG0571/02555 - 02562)		$12,750	Misc Expenses Pro Forma
8	Incremental Staff Postage Expense Adjustment	$	20,210	Line 6 - Line 7

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Miscellaneous Expenses
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 29, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
880	Other Expenses	$27,698	
903	Customer Records and Collection		$14,616
920	Administrative and General Salaries		$302,616
921	Office Supplies and Expenses		$11,124
923	Outside Services Employed		$434,641
925	Injuries and Damages		$198
926	Employee Pension and Benefits		$56,791
930.2	Miscellaneous General Expenses		$7,496
408	Other		$14,853
	Sponsorships		
874	Mains and Services		$8,167
921	Office Supplies and Expenses		$1,630
930	Miscellaneous General Expenses		$15,617
	Postage Expense		
903	**Customer Records and Collection**	**$12,750**	
	ENTRY TOTAL	**$40,448**	**$867,749**
	NET ENTRY		**$827,301**

Reason for Adjustment

To remove test year expense that should not be included in the revenue requirement because they are for out-of-period activity, they are not reflective of test year activity that should be recovered from customers, or that are year-end accruals not reflective of test year activity.

To increase postage expense to reflect the $.02 rate increase effective May 12, 2008.

UNSG Pro Forma Adjustment - Miscellaneous Expenses (for Postage Expense - Summary Pages)
Bates Nos. UNSG0571/02494 & UNSG0571/02555

✓

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Miscellaneous Expenses
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 29, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum
REVIEWED BY:	Dallas Dukes DD

JZS 9/29/08 / MB 9/29/08

FERC ACCT	FERC ACCOUNT DESCRIPTION		DEBIT	CREDIT
880	Other Expenses	~ 1a	$27,698	
903	Customer Records and Collection	~ 1b		$14,616
920	Administrative and General Salaries	~ 6a		$302,616
921	Office Supplies and Expenses	~ 1c		$11,124
923	Outside Services Employed	~ 6c		$434,641
925	Injuries and Damages	~ 6d		$198
926	Employee Pension and Benefits	~ 6e		$56,791
930.2	Miscellaneous General Expenses	~ 1d		$7,496
408	Other	~ 6g		$14,853
	Sponsorships			
874	Mains and Services	~ 8a		$8,167
921	Office Supplies and Expenses	~ 8b		$1,630
930	Miscellaneous General Expenses	~ 8c		$15,617
	Postage Expense			
903	Customer Records and Collection	~ 9a	$12,750	
	ENTRY TOTAL		**$40,448**	**$887,749**

NET ENTRY **$827,301**

Reason for Adjustment

To remove test year expense that should not be included in the revenue requirement because they are for out-of-period activity, they are not reflective of test year activity that should be recovered from customers, or that are year-end accruals not reflective of test year activity.

To increase postage expense to reflect the $.02 rate increase effective May 12, 2008.

UNSG Pro Forma Adjustment - Miscellaneous Expenses (for Postage Expense - Summary Pages)
Bates Nos. UNSG0571/02494 & UNSG0571/02555

MB 9/29/08

UNS GAS, INC.
POSTAGE EXPENSE - TEST YEAR ENDED JUNE 30, 2008
SUMMARY OF FERC ACCOUNT ADJUSTMENTS

FERC	Test Year Expense	Test Year %	Test Year Adjustment
0874	$5	0.0008%	$0
0875	$190	0.0282%	$4
0880	$5,015	0.7453%	$95
0887	$310	0.0460%	$6
0894	$261	0.0387%	$5
0902	$119	0.0177%	$2
0903	$633,444	94.1280%	$12,001
0908	$500	0.0743%	$9
0909	$169	0.0251%	$3
0921	$5,373	0.7984%	$102
0930	$27,575	4.0976%	$522
	$672,960	100.0000%	$12,750 a

Note: Increase in postage expense attributed 100% to FERC 903 since allocation to FERC accounts based on test year activity results in insignificant amounts.

9/29/2008 4:17 PM 9

UNSG0571/02555

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

				Actual				Adjusted			
Line No.	Class of Service	Rate Schedule Present	Proposed	Therm Sales	Average Number of Customers	Average Therm per Customer	Test Year End Adjustments	Therm Sales	Average Number of Customers	Average Therm per Customer	Line No
1	Residential Service	R-10	R-10	70,723,037	125,602	563	(2,656,075)	68,066,962	124,959	545	1
2	Residential Service Cares	R-12	R-12	3,478,376	6,745	516	55,060	3,533,436	7,077	499	2
3	Small Volume Commercial Service	C-20	C-20	30,119,256	11,423	2,637	(827,599)	29,291,657	11,385	2,573	3
4	Large Volume Commercial Service	C-22	C-22	1,442,578	15	95,115	(104,334)	1,338,244	14	95,589	4
5	Commercial Transportation	C-22T1	C-22T1	3,344,634	10	321,085	(303,749)	3,040,885	9	337,876	5
6	Small Volume Industrial Service	I-30	I-30	502,579	18	28,448	51,187	553,766	20	27,688	6
7	Large Volume Industrial Service	I-32	I-32	1,246,247	6	219,926	(33,594)	1,212,653	5	242,531	7
8	Industrial Transportation	I-32 T1	I-32 T1	11,443,573	12	973,921	138,953	11,582,526	13	890,964	8
9	Industrial Transportation - Contracts	I-32 T1C	I-32 T1C	7,564,291	3	2,521,430	(2,396,706)	5,167,584	3	1,722,528	
10	T2 Transportation	I-32 T2	I-32 T2	1,151,133	1	1,151,133	0	1,151,133	1	1,151,133	
11	Small Volume Public Authority	P-40	P-40	5,797,679	1,069	5,423	(185,370)	5,612,308	1,072	5,236	11
12	Large Volume Public Authority	P-42	P-42	1,225,072	5	245,014	(32,942)	1,192,130	5	238,426	12
13	Public Authority Transportation	P-42T1	P-42T1	5,127,210	7	715,425	270,621	5,397,831	8	674,729	13
14	Special Gas Light Service	P-44	P-44	145,406	2	72,703	0	145,406	2	72,703	14
15	Irrigation Service	I-60	I-60	104,267	5	20,853	(712)	103,554	5	20,711	15
16	Total Gas Service			143,415,337	144,923	990	(6,025,261)	137,390,076	144,578	950	16

Note: Some transportation customers have more than one meter which is accounted for in this schedule.

THIS DATA REQUEST RESPONSE WAS STILL PRESENTING AN INCORRECT POSTAGE EXPENSE CALCULATION

Dr.. Fish notes that two cents of the total postage for additional customers is accounted for in Line 3 of Schedule THF-C9, but this is incorrect. The two cent postage rate increase applied to existing unadjusted customer bills was accounted for on line 3 of Staff's calculation. The entire new 44 cent postage rate should be applied to the incremental customer bills resulting from the customer annualization calculation - not the 42 cents as noted by Dr. Fish below.

ARIZONA CORPORATION COMMISSION
DOCKET NO. G-04204A-08-0571
STAFF'S RESPONSE TO UNS GAS, INC.'S
SECOND SET OF DATA REQUESTS
July 1, 2009

UNSG 2.15 **Postage Expense (page 25)** –Please explain why the adjustment to Postage Expense of $49,594 in Schedule THF-C9, Line 6, is the sum of the number of customers on Line 4 and the dollar amount of the postage annualization on Line 5. If this is an error, please provide corrected calculations.

RESPONSE: **Dr. Fish's customer annualization resulted in 34,440 more customer bills being sent than Company's customer annualization. These additional customers would require postage for their bills. ~~Two cents of the total~~ postage for the additional customers is accounted for in line 3 of Schedule THF-C9, but $.42 of the postage for the additional customers is not accounted for and should be. This amount is $14,465. The total postage pro forma adjustment, then is $34,782 from line 3 plus $14,465 for a total pro forma adjustment of $49,247, not $49,594.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

STAFF ORIGINAL

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Company cust	$	34,782	Line 1 * Line 2
4	Staff Customer Annualization		34,440	Staff Schedule THF - C.1a
5	Staff Customer Annualization Postage	$	15,154	Line 4 * .44
6	Postage Expense Adjustment	$	49,594	Line 3 * Line 5

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-9
Copies of Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

****UNS Gas Confidential Information Has Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO-11-5	FERC Docket No. RP08-426 (without attachments)	Yes	3	2 - 4
RUCO-11-11	UNSG intervention in FERC proceedings	Yes	4	5 - 8
RUCO-11-20	Annual cost reductions from UNS Gas Lobby office closings	Yes	3	9 - 11
RUCO-11-22	Debit-balance ADIT and related Accrued Liabilities	Yes	15	12 - 26
RUCO-11-27 - attachment only	Purchased gas payment lag	Yes	7	27 - 33
RUCO-11-35	Outside Legal costs, budgets for 2008, 2009 and 2010	Yes	2	34 - 35
RUCO-11-39	Bonus tax depreciation and impact on ADIT	Yes	4	36 - 39
	Total Pages Including this Page		39	

ATTACHMENT RCS-9 PAGES 2-39 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Kristen K. Mayes – Chairman
Gary Pierce
Sandra D. Kennedy
Paul Newman
Bob Stump

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	**) DOCKET No. G-04204A-08-0571**

SURREBUTTAL TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF
RESIDENTIAL UTLITIY CONUSMER OFFICE OF ARIZONA

Phoenix, Arizona
July 29, 2009

SURREBUTAL TESTIMONY OF FRANK W. RADIGAN
EXECUTIVE SUMMARY

1) The Company's proposed rate design that would phase in a 65% increase in the residential customer charge over three years should be rejected. The Company has presented no new evidence in its rebuttal testimony. The main argument is that the $5.50 increase that it wishes to impose is relatively small in absolute terms and the rate shock is ameliorated by the phase-in over three years. In this testimony and my initial testimony I disagreed with a phase-in in order to avoid customer complaints and agreed to an 18% increase, $1.5 per month for Residential customers. I view this increase at the top of an acceptable bill impact range given that RUCO is recommending a 1.6% overall increase.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the 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?

A. I am appearing on behalf of the Residential Utility Consumer Office of Arizona ("RUCO").

Q. Are you the same Frank W. Radigan that previously provided testimony in this proceeding?

A. Yes, I provided the RUCO position on cost of service, revenue allocation and rate design.

Q. What is the purpose of the testimony you are presenting?

A. I have been asked to discuss the reasonableness of UNS Gas, Inc.'s ("UNS" or the "Company") rebuttal testimony on rate design.

Q. Could you please summarize the Company's rebuttal testimony?

A. The Company's proposed rate design that would phase in a $5.50 (65%) increase in the residential customer charge over three years. Company witness Erdwurm argues that too much emphasis is being placed on the bill impacts resulting from his proposal (Erdwurm Rebuttal, page 12). Mr. Erdwurm argues that when presented in percentage terms, the increase in customer charges approximates 65% and appears high, but when viewed in absolute terms, the increase in the charge over three years, from $8.50 to $14.00 per month, totals $5.50 per month, the price of a typical fast food meal (Id).

Q. Could you please comment on the Company's arguments?

A. Yes, I did support the Company proposal to increase the customer charge from $8.50 per month to $10 per month in the rate year. I felt the $1.50 per month or 17.6% increase balanced the desire to increase the customer charge to reflect the cost to serve without imposing undue rate shock. The $5.50 per month increase, 65%, would be unacceptable in terms of rate shock based on the Company's proposed rate increase of 6% and is quite unacceptable given RUCO's proposed rate increase of 1.6%. One should remember that this rate case is not the only rate case that the utility will ever have given that the Company last had a rate increase just two years ago. Thus, the argument is not that we should not be moving the customer charge closer to the cost of service, but at what pace. My recommendation is a much more measured pace than what the Company proposes.

Phasing in the increase in the customer charge does not solve the bill impact issue. As I discussed in my original testimony, a phased increase is undesirable from a customer acceptance point of view (Radigan pre-filed testimony page 6). Based on my 27 years of experience in the utility industry (gas, electric, water and steam) in which I worked for utility regulatory Commissions, public utility advocate offices, a number of municipal utilities and individual customers, customer's do not like, and do complain, about rate increases and especially outside of a rate case. A good example of customer dissatisfaction with utility rate increases is a recent United Illuminating rate case in Connecticut. As noted by the Department of Public Utility Control in its order: "The Department received more than 1000 letters and email correspondence regarding the Company's application. They were unanimous in their opposition to the proposed rate increase. Many were concerned with the state of the economy and its effect on homeowners and businesses, and their ability to pay bills." (Docket No. 08-07-04, Application of the United Illuminating Company to Increase its Rates and Charges, Final Decision issued February 4, 2009). Even if one did want to consider further increases in the customer charge, it should not be done outside of a rate case.

Q. Does this conclude your testimony?

A. Yes.

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2009

TABLE OF CONTENTS

INTRODUCTION

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

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office, located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to UNSG's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's natural gas distribution operations located in northern Arizona and Santa Cruz County.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On June 8, 2009, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in UNSG's Application that was filed on November 7, 2008.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of UNSG's rebuttal testimony; a comparison of the cost of capital recommendations being made by the parties to the case; and a section on the cost of equity capital.

Q. Will you address the FVROR issues associated with the case?

A. No. RUCO consultant Ralph Smith will discuss the FVROR aspects of the case.

SUMMARY OF UNSG GAS, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNSG'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimonies of Company witnesses David G. Hutchens and Kentton C. Grant, which were filed on July 8, 2009.

Q. Please summarize Mr. Hutchens's rebuttal testimony.

A. Mr. Hutchens' rebuttal testimony addresses all of the points of disagreement that the Company has with ACC Staff and RUCO. In regard to cost of capital, Mr. Hutchens expresses his displeasure with the FVROR recommendations of ACC Staff and RUCO.

Q. Please summarize Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony expresses his belief that the cost of equity recommendation presented in my direct testimony is too low and criticizes my decision to average the results of my single stage DCF model with the results of my CAPM models (which used both an arithmetic and geometric mean to arrive at the market risk premium component).

COMPARISON OF RECOMMENDATIONS

Q. Are the parties to the case in agreement on the issue of capital structure?

A. Yes, the parties to the case are in agreement on the issue of capital structure. Both ACC Staff and RUCO are recommending that the Commission adopt the Company-proposed capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. Are ACC Staff and RUCO also in agreement with the Company-proposed 6.49 percent cost of long-term debt?

A. Yes. ACC Staff witness David C. Parcell and I have recommended that the Commission adopt the Company-proposed 6.49 percent cost of long-term debt.

Q. Are UNSG, ACC Staff and RUCO in agreement on a cost of equity capital for the Company?

A. No. As is typical in utility rate cases there is substantial disagreement on a cost of common equity.

Q. Please summarize the costs of common equity and the OCROR's that are being recommended by the parties to the case.

A. In regard to the cost of common equity, the parties to the case are presently recommending the following estimates:

UNSG	11.00%
ACC Staff	10.00%
RUCO	8.61%

As can be seen in the above comparison, the Company-proposed cost of equity capital is 239 basis points higher than my recommended cost of equity capital. The difference between my recommended cost of equity and Mr. Parcell's recommended cost of equity is 139 basis points. The OCROR (i.e. the weighted cost of capital based on the costs of debt and equity noted above) being recommended by the parties to the case are as follows:

UNSG	8.75%
ACC Staff	8.24%
RUCO	7.55%

As can be seen above, there is presently a 120 basis point difference between the Company-proposed 8.75 percent OCROR (before any FVROR adjustment) and RUCO's recommended weighted cost of capital of 7.55 percent. RUCO and ACC Staff's recommended OCROR are within 69 basis points of each other.

Q. What FVROR's are the parties to the case recommending?

A. The parties to the case are recommending the following FVROR's:

UNSG	6.80%
ACC Staff	6.03%
RUCO	5.38%

The above comparison shows a difference of 142 basis points between the Company and RUCO's recommended FVROR's and a difference of 65 basis points between the ACC Staff and RUCO recommendations.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On June 24, 2009, after a two-day meeting, the Federal Reserve chose not to enlarge its program to buy Treasury bonds to spur growth and stated again that its key Federal Funds interest rate will remain near zero "for an extended period." The Fed also announced that it will proceed with its previously announced plans to buy up to $300 billion in long-term U.S. Treasury bonds by autumn and up to $1.25 trillion in mortgage-backed securities by year's end. The Fed further stated that it would "continue to evaluate the timing and overall amounts" of the purchases of the aforementioned financial instruments.[1]

...

[1] Reddy, Sudeep and Geoffrey T. Smith, "Fed on Holds as Slump Eases" The Wall Street Journal, June 25, 2009

Q. Has Value Line published an update on the natural gas utility industry since you filed your direct testimony?

A. Yes. Value Line published its quarterly update on the natural gas utility industry on June 12, 2009.

Q. Have you updated your recommended cost of common equity based on more recent information on interest rates and the latest Value Line data on the natural gas utility industry?

A. Yes. Based on updated information I have obtained a cost of equity estimate that is approximately 30 basis points lower than the 8.61 percent cost of equity that I recommended in my direct testimony filed on June 12, 2009.

Q. Are you revising your recommended cost of equity capital based on your updated results?

A. No. I believe that my original 8.61 percent estimate is still reasonable given the current state of interest rates and the current state of the economy.

...

Q. Please address Mr. Grant's criticism that the 5-year Treasury rate that you used as the risk free rate of return in your CAPM models is not reflective of the "investment period" used by investors to value common stocks.

A. Mr. Grant has expressed the broad assumption that the "relevant" period that the investment community relies on to value common stocks is "a very long period." But the fact is that utilities typically file for rates within a three to five-year period and the investment community is aware of that fact and understands the effect of rate case proceedings on earnings. Information on rate case proceedings is available to investors through SEC filings, investment research firms such as Value Line, and the mainstream financial press. One only has to look at UNSG as proof of this. The Company's prior rates were established on November 8, 2007 and UNSG filed for new rates almost one year later to the day for new rates. Any investor who follows the Company's publicly traded parent would be aware of the impact that the Company's actions would have on future earnings and would base his or her investment decisions based on that information.

Q. Can you cite another reason why you believe the 5-year treasury instrument used in your CAPM analysis is appropriate?

A. Yes. Professional analysts at investment services such as Value Line and Zacks Investment Research typically do not make projections beyond five years. In fact, the Federal Energy Regulatory Commission ("FERC") places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model that Mr. Grant used to arrive at his 11.00 percent cost of equity recommendation.

Q. Please explain how the FERC places more emphasis on short-term projections in the multi-stage DCF model.

A. The multi-stage DCF model required by the FERC weighs short-term estimates of growth, similar to the one to five-year projections that I relied on to develop the "g" component in my single stage DCF model, by a factor of two-thirds. The FERC's rationale is that short-term estimates of growth are more predictable and deserve more weight than long-term estimates such as the equally-weighted long-term estimates of growth used in the multi-stage DCF model that Mr. Grant has relied on. This is explained in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment A):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity

> return is then selected within this zone based on an analysis of the company's risk."

Q. Please explain why Mr. Grant's criticism regarding the use of a geometric mean in a CAPM analysis is unfounded.

A. The information on both the geometric and arithmetic means, published by Morningstar, is widely available to the investment community. For this reason alone I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2007 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the difference between arithmetic and geometric means?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

(year 1 return + year 2 return) ÷ number of periods =

(20.0% + -20.0%) ÷ 2 =

(0.0%) ÷ 2 = 0.0%

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original \$100 investment is still worth \$100. But in reality, your original \$100 investment is only worth \$96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{ year 2 value} \div \text{original value })^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{-2.02\%}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original \$100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concluded that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 2.23 percent to these two estimates indicates a cost of equity range of 6.23 percent to 7.73 percent. Taking into consideration the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range would be reasonable. In fact, my 8.61 percent cost of common equity estimate is 88 basis points more than the high end of the range exhibited above.

Q. Has the Commission authorized rates of return that were derived through the use of both arithmetic and geometric means in prior decisions?

A. Yes.

Q. Can you provide further support for the reasonableness of the market risk premiums used in your CAPM models?

A. Yes. In his direct testimony in a prior Arizona Public Service Company ("APS") rate case proceeding, RUCO consultant Stephen G. Hill makes the argument for market risk premiums ranging from 4.0 percent to 6.0 percent[2] (Attachment B). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two scholarly articles on the subject published by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University

[2] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswath Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model?

A. Using an updated 2.23 percent yield on a 5-year Treasury instrument (r_f), an updated beta of 0.67 (published in the recent Value Line natural gas utility industry update), and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, in my CAPM model produces the following results:

Using a 4.0% Market Risk Premium

$k = r_f + [\,ß\,(r_m - r_f)\,]$

$k = 2.23\% + [\,0.67\,(4.0\%)\,]$

$k = 2.23\% + 2.68\%$

$k = \underline{4.91\%}$

Using a 6.0% Market Risk Premium

$k = r_f + [\,ß\,(r_m - r_f)\,]$

$k = 2.23\% + [\,0.67\,(6.0\%)\,]$

$k = 2.23\% + 4.02\%$

$k = \underline{6.25\%}$

These results are lower than the 5.26 percent and 6.39 percent estimates that I used to calculate my recommended 8.61 percent cost of common equity. When the market risk premium information noted above is taken into consideration, it is clear that Mr. Grant's market risk premium inputs, as opposed to mine, appear to be out of line.

Q. Do you have any data that supports a 4.00 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled <u>Equity Risk Premium (ERP): Determinants, Estimation and Implications</u>, which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range is 65 basis points lower than the 5.95 percent average of my market risk premium using both geometric and arithmetic means.

Q. Please respond to Mr. Grant's statement that he is "shocked" that you would give weight to the low numbers produced by your CAPM analysis.

A. I see no reason to be shocked when one considers the current state of lower interest rates on low risk investments such as U.S. Treasury instruments and various bank certificates of deposit (Attachment C). The results of my CAPM analyses (using both arithmetic and geometric means) are simply reflecting this situation. From the perspective that public utilities have traditionally been viewed as safe investments, all things being equal it is not reasonable to believe that their costs of equity capital should be in the 11.00 percent level advocated by Mr. Grant.

Q. Please address Mr. Grant's argument that common shareholders bear a higher risk than bond holders and expect a higher return than the yields of utility debt instruments.

A. I do not disagree with Mr. Grant on this point. The question is how much more of a risk premium is merited for a low risk regulated monopoly such as UNSG. My recommended 8.61 percent cost of common equity capital is 220 basis points higher than UNSG's 6.49 percent cost of debt. It is also 176 basis points higher than the recent 6.85 percent yield on Baa/BBB-rated utility bond and 290 basis points higher than the recent 5.71 percent yield on an A-rated utility bond. The yields of both of the aforementioned utility bonds have been in decline since I filed my direct testimony on June 12, 2009.

Q. How do the current yields on Baa/BBB and A-rated utility bonds compare to the yields displayed in Mr. Grant's rebuttal testimony Exhibit KCG-15?

A. Mr. Grant's Exhibit KCG-15 displays Baa-rated and A-rated yields of 8.00 percent and 6.50 percent respectively. However these yields were published in March of 2009. Since then they have declined by 115 and 79 basis points respectively. It would appear that utility bonds are moving in the same downward direction as the yields of other financial instruments.

Q. Has Mr. Grant made any updates to the inputs of his models that were used to derive his recommended cost of common equity?

A. No. Mr. Grant has made no attempt to revise the Company-proposed cost of equity capital by updating the inputs to his models.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on UNSG?

A. Yes, it does.

ATTACHMENT A

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Table of Contents

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

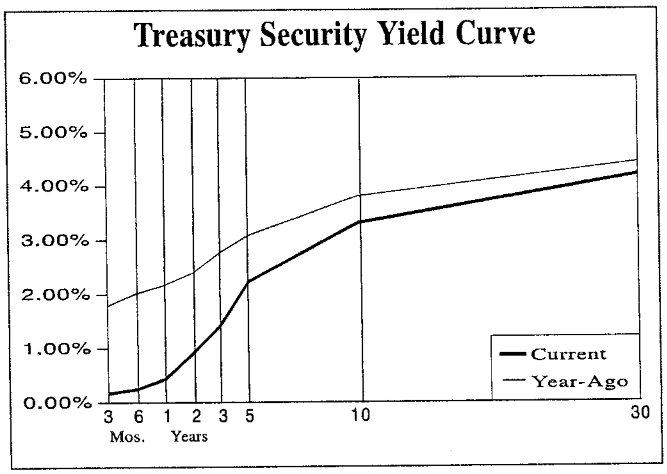
[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

ATTACHMENT C

Selected Yields

	Recent (7/08/09)	3 Months Ago (4/08/09)	Year Ago (7/09/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.36	0.33	2.62
3-month LIBOR	0.53	1.14	2.79
Bank CDs			
6-month	0.65	0.83	1.64
1-year	0.86	1.04	2.34
5-year	1.94	2.05	3.74
U.S. Treasury Securities			
3-month	0.18	0.18	1.79
6-month	0.25	0.37	2.02
1-year	0.44	0.58	2.18
5-year	2.23	1.83	3.08
10-year	3.31	2.86	3.81
10-year (inflation-protected)	1.76	1.53	1.23
30-year	4.19	3.67	4.42
30-year Zero	4.31	3.67	4.46



	Recent (7/08/09)	3 Months Ago (4/08/09)	Year Ago (7/09/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.71	3.40	5.41
FHLMC 6.5% (Gold)	2.99	2.79	5.42
FNMA 6.5%	2.83	2.79	5.32
FNMA ARM	2.98	3.15	4.09
Corporate Bonds			
Financial (10-year) A	6.53	7.85	6.08
Industrial (25/30-year) A	5.82	6.27	6.04
Utility (25/30-year) A	5.71	6.20	6.25
Utility (25/30-year) Baa/BBB	6.85	7.63	6.35
Foreign Bonds (10-Year)			
Canada	3.28	2.90	3.69
Germany	3.28	3.21	4.41
Japan	1.30	1.46	1.62
United Kingdom	3.62	3.35	4.89
Preferred Stocks			
Utility A	7.59	6.35	6.27
Financial A	6.57	7.80	7.75
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.83	4.95	4.83
25-Bond Index (Revs)	5.75	5.75	5.25
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.47	1.78
1-year A	0.93	1.20	1.80
5-year Aaa	1.96	2.03	3.33
5-year A	2.40	3.45	3.43
10-year Aaa	3.09	3.20	3.90
10-year A	3.45	4.75	4.10
25/30-year Aaa	4.59	4.77	4.74
25/30-year A	5.05	6.25	4.84
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.55	6.30	5.03
Electric AA	5.65	6.40	5.05
Housing AA	5.80	6.70	5.10
Hospital AA	5.90	6.65	5.15
Toll Road Aaa	5.60	6.45	5.05

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 7/1/09	6/17/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	687739	791810	-104071	805680	768030	503132
Borrowed Reserves	404097	458240	-54143	512001	551755	480824
Net Free/Borrowed Reserves	283642	333570	-49928	293678	216275	22308

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

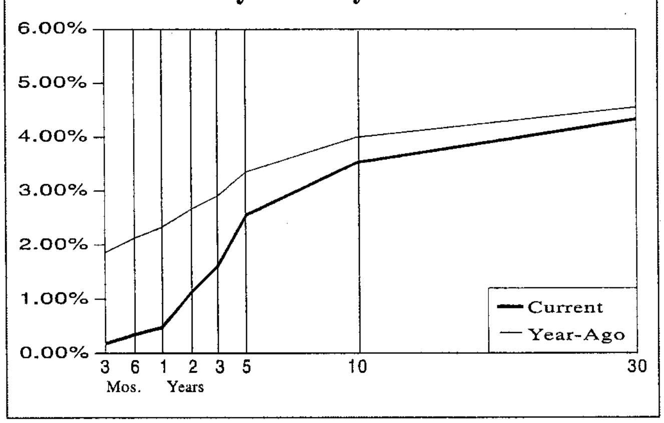
	Recent Levels 6/22/09	6/15/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1668.5	1656.0	12.5	33.3%	9.1%	20.7%
M2 (M1+savings+small time deposits)	8369.2	8368.9	0.3	1.4%	5.7%	9.3%

Selected Yields

TAXABLE	Recent (6/30/09)	3 Months Ago (4/01/09)	Year Ago (7/01/08)
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.41	0.44	2.65
3-month LIBOR	0.60	1.18	2.79
Bank CDs			
6-month	0.65	0.83	1.75
1-year	0.86	1.04	2.43
5-year	1.92	2.06	3.75
U.S. Treasury Securities			
3-month	0.18	0.20	1.86
6-month	0.34	0.39	2.12
1-year	0.48	0.54	2.33
5-year	2.56	1.64	3.35
10-year	3.53	2.65	4.00
10-year (inflation-protected)	1.80	1.32	1.35
30-year	4.33	3.50	4.55
30-year Zero	4.41	3.52	4.57

	Recent (6/30/09)	3 Months Ago (4/01/09)	Year Ago (7/01/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.77	3.53	5.60
FHLMC 6.5% (Gold)	3.23	3.12	5.59
FNMA 6.5%	3.07	3.04	5.51
FNMA ARM	2.53	3.15	4.09
Corporate Bonds			
Financial (10-year) A	6.87	7.49	6.37
Industrial (25/30-year) A	5.96	6.17	6.16
Utility (25/30-year) A	5.79	5.99	6.24
Utility (25/30-year) Baa/BBB	6.88	7.41	6.43
Foreign Bonds (10-Year)			
Canada	3.36	2.78	3.74
Germany	3.39	2.99	4.61
Japan	1.36	1.35	1.68
United Kingdom	3.69	3.13	5.15
Preferred Stocks			
Utility A	6.10	6.74	6.25
Financial A	7.75	9.90	7.28
Financial Adjustable A	5.48	5.48	5.48

Treasury Security Yield Curve



TAX-EXEMPT	Recent (6/30/09)	3 Months Ago (4/01/09)	Year Ago (7/01/08)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.79	5.00	4.83
25-Bond Index (Revs)	5.77	5.78	5.25
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.50	1.78
1-year A	1.10	0.60	1.80
5-year Aaa	2.07	2.08	3.33
5-year A	3.47	2.33	3.43
10-year Aaa	3.23	3.20	3.90
10-year A	4.75	3.73	4.10
25/30-year Aaa	4.66	4.79	4.74
25/30-year A	6.18	5.83	4.84
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.05	5.80	5.03
Electric AA	6.10	5.85	5.05
Housing AA	6.50	6.15	5.10
Hospital AA	6.45	6.20	5.15
Toll Road Aaa	6.05	5.90	5.05

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	6/17/09	6/3/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	791810	838497	-46687	817610	774222	477725
Borrowed Reserves	458240	497684	-39444	540680	571070	472226
Net Free/Borrowed Reserves	333570	340813	-7243	276930	203152	5499

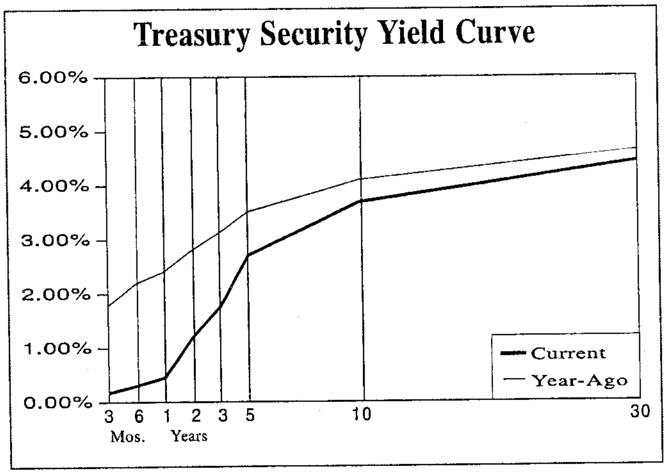
MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	6/15/09	6/8/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1656.9	1631.1	25.8	25.5%	7.2%	19.8%
M2 (M1+savings+small time deposits)	8369.3	8353.6	15.7	1.3%	6.4%	9.5%

Selected Yields

	Recent (6/24/09)	3 Months Ago (3/25/09)	Year Ago (6/25/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.44	0.51	2.80
3-month LIBOR	0.60	1.23	2.81
Bank CDs			
6-month	0.65	0.83	1.75
1-year	0.87	1.04	2.41
5-year	1.92	2.06	3.75
U.S. Treasury Securities			
3-month	0.18	0.18	1.79
6-month	0.31	0.40	2.20
1-year	0.46	0.58	2.42
5-year	2.71	1.81	3.52
10-year	3.69	2.78	4.10
10-year (inflation-protected)	1.88	1.38	1.51
30-year	4.43	3.74	4.64
30-year Zero	4.50	3.77	4.66



	Recent (6/24/09)	3 Months Ago (3/25/09)	Year Ago (6/25/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.79	3.48	5.68
FHLMC 6.5% (Gold)	3.28	2.99	5.64
FNMA 6.5%	3.06	3.00	5.55
FNMA ARM	2.53	3.60	4.30
Corporate Bonds			
Financial (10-year) A	6.75	7.51	6.22
Industrial (25/30-year) A	6.07	6.48	6.19
Utility (25/30-year) A	5.89	6.28	6.25
Utility (25/30-year) Baa/BBB	7.30	7.71	6.48
Foreign Bonds (10-Year)			
Canada	3.45	2.96	3.71
Germany	3.42	3.15	4.61
Japan	1.39	1.29	1.69
United Kingdom	3.70	3.28	5.12
Preferred Stocks			
Utility A	6.05	6.11	6.21
Financial A	8.21	9.42	7.20
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.86	4.98	4.76
25-Bond Index (Revs)	5.78	5.81	5.20
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.50	1.70
1-year A	0.90	0.60	1.80
5-year Aaa	2.17	2.15	3.40
5-year A	2.60	2.45	3.50
10-year Aaa	3.27	3.24	4.00
10-year A	3.63	3.74	4.20
25/30-year Aaa	4.70	4.85	4.88
25/30-year A	5.15	5.85	5.08
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	5.90	5.10
Electric AA	5.90	6.00	5.15
Housing AA	6.10	6.30	5.30
Hospital AA	6.05	6.25	5.40
Toll Road Aaa	5.85	6.05	5.15

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	6/17/09	6/3/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	791801	838494	-46693	817609	774221	477725
Borrowed Reserves	458240	497684	-39444	540680	571070	472226
Net Free/Borrowed Reserves	333561	340810	-7249	276928	203151	5499

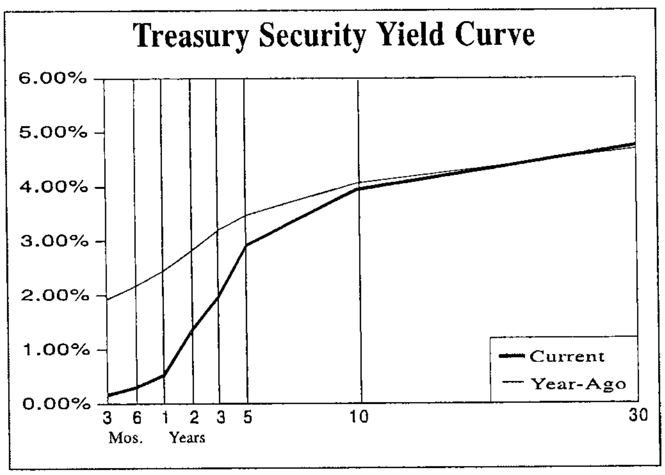
MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	6/8/09	6/1/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1631.1	1596.8	34.3	14.4%	6.9%	17.6%
M2 (M1+savings+small time deposits)	8353.8	8349.4	4.4	2.2%	7.2%	9.3%

Selected Yields

	Recent (6/10/09)	3 Months Ago (3/11/09)	Year Ago (6/11/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.34	0.75	2.53
3-month LIBOR	0.64	1.33	2.79
Bank CDs			
6-month	0.66	0.84	1.76
1-year	0.87	1.05	2.25
5-year	1.92	2.07	3.37
U.S. Treasury Securities			
3-month	0.17	0.22	1.94
6-month	0.31	0.45	2.17
1-year	0.53	0.70	2.45
5-year	2.92	1.94	3.47
10-year	3.95	2.91	4.07
10-year (inflation-protected)	1.86	2.01	1.47
30-year	4.76	3.66	4.69
30-year Zero	4.84	3.56	4.74



	Recent (6/10/09)	3 Months Ago (3/11/09)	Year Ago (6/11/08)
Mortgage-Backed Securities			
GNMA 6.5%	4.26	4.21	5.69
FHLMC 6.5% (Gold)	3.07	3.58	5.68
FNMA 6.5%	2.91	3.73	5.58
FNMA ARM	2.53	3.60	4.30
Corporate Bonds			
Financial (10-year) A	6.82	7.38	5.86
Industrial (25/30-year) A	6.50	6.18	6.25
Utility (25/30-year) A	6.28	6.05	6.23
Utility (25/30-year) Baa/BBB	7.76	7.50	6.50
Foreign Bonds (10-Year)			
Canada	3.64	2.92	3.81
Germany	3.69	3.07	4.55
Japan	1.55	1.32	1.85
United Kingdom	3.92	3.09	5.13
Preferred Stocks			
Utility A	7.62	6.96	6.33
Financial A	8.63	11.44	6.76
Financial Adjustable A	5.46	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.71	4.96	4.59
25-Bond Index (Revs)	5.63	5.80	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.57	1.74
1-year A	0.90	0.67	1.84
5-year Aaa	2.14	2.30	3.07
5-year A	2.57	2.55	3.17
10-year Aaa	3.21	3.30	3.74
10-year A	3.57	3.83	3.94
25/30-year Aaa	4.72	4.87	4.56
25/30-year A	5.16	5.91	4.76
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.85	5.90	4.85
Electric AA	5.95	5.95	4.90
Housing AA	6.25	6.25	5.05
Hospital AA	6.20	6.30	5.15
Toll Road Aaa	6.00	6.00	4.90

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	6/3/09	5/20/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	838496	877071	-38575	793290	759788	448486
Borrowed Reserves	497684	554779	-57095	565243	586617	461783
Net Free/Borrowed Reserves	340812	322292	18520	228048	173171	-13297

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

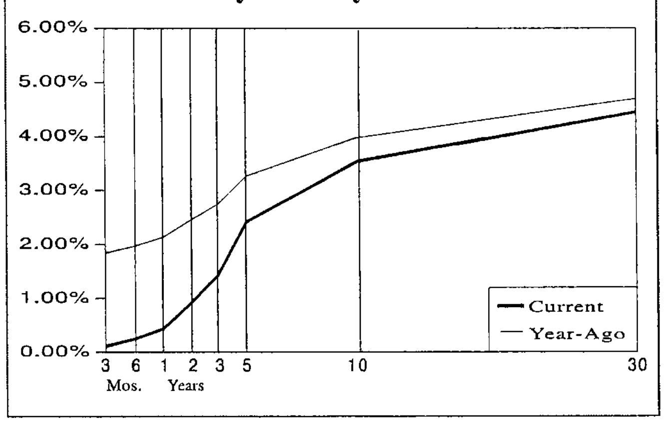
	Recent Levels			Growth Rates Over the Last...		
	5/25/09	5/18/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1602.2	1590.0	12.2	16.2%	10.9%	16.8%
M2 (M1+savings+small time deposits)	8358.2	8327.4	30.8	6.0%	10.1%	9.2%

Selected Yields

	Recent (6/3/09)	3 Months Ago (3/04/09)	Year Ago (6/04/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.28	0.79	2.47
3-month LIBOR	0.64	1.28	2.67
Bank CDs			
6-month	0.70	0.84	1.76
1-year	0.92	1.04	2.25
5-year	1.92	2.07	3.37
U.S. Treasury Securities			
3-month	0.12	0.25	1.84
6-month	0.25	0.43	1.97
1-year	0.44	0.66	2.13
5-year	2.42	1.94	3.26
10-year	3.54	2.97	3.98
10-year (inflation-protected)	1.63	2.03	1.44
30-year	4.45	3.67	4.70
30-year Zero	4.53	3.55	4.79

	Recent (6/3/09)	3 Months Ago (3/04/09)	Year Ago (6/04/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.37	4.19	5.49
FHLMC 6.5% (Gold)	2.89	4.13	5.46
FNMA 6.5%	2.78	4.15	5.36
FNMA ARM	2.53	3.60	4.25
Corporate Bonds			
Financial (10-year) A	6.82	8.50	5.74
Industrial (25/30-year) A	6.35	6.23	6.22
Utility (25/30-year) A	6.17	5.93	6.23
Utility (25/30-year) Baa/BBB	7.83	7.16	6.50
Foreign Bonds (10-Year)			
Canada	3.36	3.02	3.64
Germany	3.57	3.14	4.38
Japan	1.55	1.31	1.78
United Kingdom	3.79	3.64	4.95
Preferred Stocks			
Utility A	6.10	7.62	6.29
Financial A	8.35	12.59	6.75
Financial Adjustable A	5.53	5.53	5.53
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.61	4.87	4.52
25-Bond Index (Revs)	5.53	5.76	4.99
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.57	1.77
1-year A	1.13	0.67	1.87
5-year Aaa	2.02	2.30	2.94
5-year A	3.45	2.90	3.04
10-year Aaa	3.01	3.29	3.58
10-year A	4.55	3.79	3.78
25/30-year Aaa	4.64	4.86	4.47
25/30-year A	6.16	5.86	4.67
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.20	5.90	4.75
Electric AA	6.25	6.00	4.80
Housing AA	6.55	6.25	4.95
Hospital AA	6.50	6.20	5.05
Toll Road Aaa	6.30	6.05	4.80

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/20/09	5/6/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	877072	777457	99615	769710	743091	417505
Borrowed Reserves	554779	507911	46868	578275	602866	449070
Net Free/Borrowed Reserves	322293	269546	52747	191435	140225	-31565

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/18/09	5/11/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1590.2	1596.0	-5.8	8.0%	10.2%	16.4%
M2 (M1+savings+small time deposits)	8327.5	8315.3	12.2	4.0%	10.2%	9.1%

ATTACHMENT D

Equity Risk Premiums (ERP): Determinants, Estimation and Implications

September 2008

(with an October update reflecting the market crisis)

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Equity Risk Premiums (ERP): Determinants, Estimation and Implications

Equity risk premiums are a central component of every risk and return model in finance and are a key input into estimating costs of equity and capital in both corporate finance and valuation. Given their importance, it is surprising how haphazard the estimation of equity risk premiums remains in practice. In the standard approach to estimating equity risk premiums, historical returns are used, with the difference in annual returns on stocks versus bonds over a long time period comprising the expected risk premium. We note the limitations of this approach, even in markets like the United States, which have long periods of historical data available, and its complete failure in emerging markets, where the historical data tends to be limited and volatile. We look at two other approaches to estimating equity risk premiums – the survey approach, where investors and managers ar asked to assess the risk premium and the implied approach, where a forward-looking estimate of the premium is estimated using either current equity prices or risk premiums in non-equity markets. We close the paper by examining why different approaches yield different values for the equity risk premium, and how to choose the "right" number to use in analysis. (In an addendum, we also look at equity risk premiums during the market crisis, starting on September 12, 2008 through October 16, 2008.)

This regression reinforces the view that equity risk premiums should not be constants but should be linked to the level of interest rates, at the minimum, and perhaps even to the slope of the yield curve. In Septermber 2008, for instance, when the 10-year treasury bond rate was 3.55% and the 6-month treasury bill rate was at 2.4%, the implied equity risk premium would have been computed as follows:

Implied ERP = 1.93% + 0.371 (3.55%) - .111 (3.55% – 2.4%) = 3.12%

This would have been well below the observed implied equity risk premium of about 4.54% and the average implied equity risk premium of 4% between 1960 and 2008.

While we have considered only interest rates in this analysis, it can be expanded to include other fundamental variables including measures of overall economic growth (such as expected growth in the GDP), exchange rates and even measures of risk aversion.

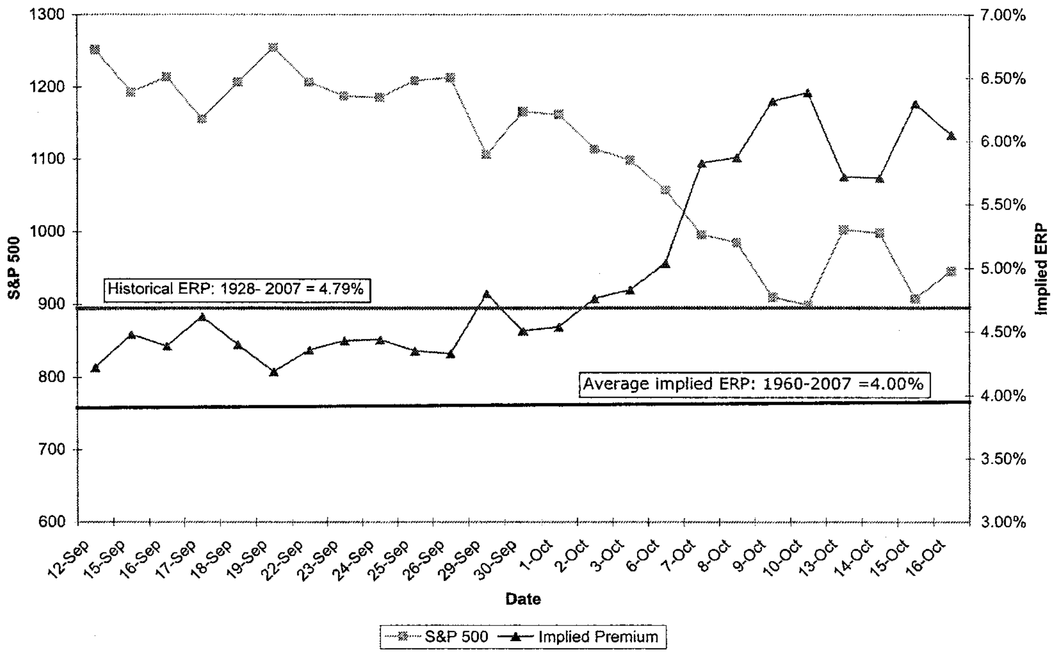
Implied Equity Risk Premiums during a Market Crisis – 9/15/08 to 10/16/08

When we use historical risk premiums, we are, in effect, assuming that equity risk premiums do not change much over short periods and revert back over time to historical averages. This assumption was viewed as reasonable for mature equity markets like the United States, but was put under a severe test during the market crisis that unfolded with the fall of Lehman Brothers on September 15, and the subsequent collapse of equity markets, first in the US, and then globally.

Since implied equity risk premiums reflect the current level of the index, the 22 trading days between September 15, 2008, and October 16, 2008, offer us an unprecedented opportunity to observe how much the price charged for risk can change over short periods. In figure 7A, we depict the S&P 500 on one axis and the implied equity risk premium on the other. To estimate the latter, we used the level of the index and the treasury bond rate at the end of each day and used the total dollar dividends and buybacks over the trailing 12 months to compute the total yield. For example, the total dollar dividends and buybacks on the index for the trailing 12 months of 52.58 resulted in a dividend yield of 4.20% on September 12 (when the index closed at 1252) but jumped to 4.97% on October 6, when the index closed at 1057.[71]

[71] It is possible, and maybe even likely, that the banking crisis and resulting economic slowdown was leading some companies to reassess policies on buybacks. Alcoa, for instance, announced that it was terminating stock buybacks. However, other companies stepped up buybacks in response to lower stock prices. If the total cash return was dropping, as the market was, the implied equity risk premiums should be lower than the numbers that we have computed.

Figure 7A: Implied Equity Risk Premium - 9/12- 10/16



In a period of a month, the implied equity risk premium rose from 4.20% on September 12 to 6.39% at the close of trading of October 10. Even more disconcertingly, there were wide swings in the equity risk premium within a day; in the last trading hour just on October 10, the implied equity risk premium ranged from a high of 6.6% to a low of 6.1%.

There are two ways in which we can view this volatility. One the one side, proponents of using historical averages (either of actual or implied premiums) will use the day-to-day volatility in market risk premiums to argue for the stability of historical averages. They are implicitly assuming that when the crisis passes, markets will return to the status quo. On the other hand, there will be many who point to the unprecedented jump in implied premiums over a four-week period and note the danger of sticking with a "fixed" premium. They will argue that there are sometimes structural shifts in markets, i.e. big events that change market risk premiums for long periods, and that we should be therefore modifying the risk premiums that we use in valuation as the market changes around us.

There is one final point to be made about the changes in risk premiums during this crisis. The volatility captured in figure 7A was not restricted to just the US equity markets. Global equity markets gyrated with and sometimes more than the US, default spreads widened considerably in corporate bond markets, commercial paper and LIBOR rates soared while the 3-month treasury bill rate dropped close to zero and the implied volatility in option markets rose to levels never seen before. Gold surged but other commodities, such as oil and grains, dropped. Not only did we discover how intertwined equity markets are around the globe but also how markets for all risky assets are tied together. We will explicitly consider these linkages as we go through the rest of the paper.

Extensions of Implied Equity Risk Premium

The practice of backing out risk premiums from current prices and expected cashflows is a flexible one. It can be expanded into emerging markets to provide estimates of risk premiums that can replace the country risk premiums we developed in the last section. Within an equity market, it can be used to compute implied equity risk premiums for individual sectors or even classes of companies.

a. Other Equity Markets

The advantage of the implied premium approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market, no matter how short its history, It is, however, bounded by whether the model used for the valuation is the right one and the availability and reliability of the inputs to that model. Earlier in this paper, we estimated country risk premiums for Brazil, using default spreads and equity market volatile. To provide a contrast, we estimated the implied equity risk premium for the Brazilian equity market in September 2008, from the following inputs.

- The index (Bovespa) was trading at 48,345 on September 9, 2008, and the dividend yield on the index over the previous 12 months was approximately 2%. While stock buybacks represented negligible cash flows, we did compute the FCFE for companies in the index, and the aggregate FCFE yield across the companies was 5.41%.
- Earnings in companies in the index are expected to grow 9% (in US dollar terms) over the next 5 years, and 3.80% (set equal to the treasury bond rate) thereafter.
- The riskfree rate is the US 10-year treasury bond rate of 3.80%.

The time line of cash flows is shown below:

$$48{,}345 = \frac{2{,}853}{(1+r)} + \frac{3{,}109}{(1+r)^2} + \frac{3{,}389}{(1+r)^3} + \frac{3{,}694}{(1+r)^4} + \frac{4{,}027}{(1+r)^5} + \frac{4{,}027(1.038)}{(r-.038)(1+r)^5}$$

These inputs yield a required return on equity of 10.78%, which when compared to the treasury bond rate of 3.80% on that day results in an implied equity premium of 6.98%.