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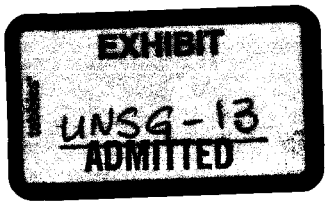

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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT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

Direct Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

November 7, 2008

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am Vice President of Finance and Rates for UniSource Energy Corporation ("UniSource Energy") and Tucson Electric Power Company ("TEP"). In this role I am responsible for providing financial and regulatory support services to UniSource Energy and its regulated utility subsidiaries. These subsidiaries include UNS Gas, Inc. ("UNS Gas" or the "Company"), UNS Electric, Inc. ("UNS Electric") and TEP.

Q. Please summarize your professional experience and education.

A. I received a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA. I am also a member of the Society of Utility and Regulatory Financial Analysts, and in 1992, I was awarded the designation of Certified Rate of Return Analyst ("CRRA").

From 1984 to 1995, I was employed by the Public Utility Commission of Texas. During this period I served in various staff positions, including Director of the Financial Review Division. In that role I directed a staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities. As a staff member I provided expert testimony on a variety of financial topics including

the cost of capital, financial integrity, rate moderation and the valuation of utility properties.

I joined TEP in 1995 as a senior financial analyst. In 1997, I was promoted to Director of Capital Resources and elected Assistant Treasurer. I was subsequently promoted to Manager of Financial Planning and in 2003, became a General Manager in TEP's Shared Services Unit. In January 2007, I was elected Vice President of Finance and Rates for both TEP and UniSource Energy. In these roles I have gained extensive experience in financial forecasting, financial analysis, the structuring of new financings and other related activities.

Q. What is the purpose of your Direct Testimony?

A. In my Direct Testimony I support UNS Gas' request for a rate increase by: (i) providing an overview of the Company's financial condition; (ii) recommending a fair rate of return on common equity capital; (iii) determining the weighted average cost of capital ("WACC") for UNS Gas; and (iv) recommending a fair rate of return ("ROR") on fair value rate base ("FVRB"). I also discuss the appropriate carrying cost to be applied to balances under the Company's purchased gas adjustor ("PGA") rate mechanism, and sponsor several schedules including Schedule A-3 (Summary Capital Structure), Schedule A-4 (Construction Expenditures and Gross Plant in Service), the "D" Schedules (Cost of Capital Information) and the "F" Schedules (Projections and Forecasts) that were filed in support of UNS Gas' rate request.

Q. Please summarize your recommendations concerning the cost of capital to UNS Gas and the appropriate ROR to be applied to FVRB.

A. With regard to the Company's cost of capital, I estimate the weighted average cost to be 8.75%. This WACC is based on a 6.49% cost of debt, an 11.0% cost of common equity

capital, and a capital structure consisting of 50.01% long-term debt and 49.99% common equity.

With regard to the ROR to be applied to FVRB, I recommend a ROR of 6.80%, even though a higher value could be justified based on the methodology recently adopted by the Arizona Corporation Commission ("Commission") in the Chaparral City Water remand docket, (Decision No. 70441 (July 28, 2008)). This ROR, when applied to the Company's FVRB of approximately $256 million, should enable UNS Gas to attract capital on reasonable terms and provide the Company with an opportunity to earn a fair return on equity ("ROE") close to the 11.0% cost of equity identified above.

Q. What carrying cost do you recommend be applied to the Company's future PGA balances?

A. I recommend the use of a rate that reflects the actual cost to UNS Gas of financing PGA cost deferrals. The current rate used to accrue carrying costs on the PGA balance is the three-month financial commercial paper rate published by the U.S. Federal Reserve. This rate is significantly lower than the actual cost of short-term borrowing by UNS Gas, which is equal to the London Interbank Offered Rate ("LIBOR") on dollar deposits plus a credit margin of one percent. Consequently, I recommend use of the three-month LIBOR rate plus one percent for purposes of accruing carrying costs on the PGA balance.

II. FINANCIAL CONDITION OF UNS GAS.

Q. Please describe UNS Gas' current financial condition.

A. UNS Gas has a mixed financial profile. On the positive side, the Company has a healthy mix of debt and equity capital and a relatively low cost of long-term debt. The Company's earnings and cash flow have also improved due to the base rate increase

approved in 2007 by the Commission. However, even with this rate increase, it is unlikely the Company will be able to earn the 10.0% ROE authorized by the Commission in that rate proceeding (Decision No. 70011). This is due largely to the wide gap between the embedded cost of utility plant reflected in the Company's current rates and the higher cost of utility plant added since December 31, 2005, the test year in UNS Gas' last rate case. Internal cash flow at UNS Gas is also quite weak relative to the Company's annual capital spending requirements for new plant and equipment. Continued weakness in the Company's earnings and cash flow, coupled with the lack of any dividend on shareholder capital, places UNS Gas at a competitive disadvantage in terms of attracting the capital needed for utility plant investment.

Q. What steps has the Company taken to improve its financial condition over time?

A. Since the acquisition of gas distribution properties from Citizens Communications Company ("Citizens") in 2003, UNS Gas' balance of common equity capital has nearly doubled from $50 million to $99 million as of June 30, 2008. This has been achieved through the retention of 100% of annual earnings at UNS Gas and an additional equity infusion of $16 million made by UniSource Energy. As a result, the Company's ratio of common equity to total capital has improved from 33% in August of 2003 to approximately 50% as of the test year ending June 30, 2008. Over time UNS Gas has also taken steps to reduce its operating costs wherever feasible and to realize additional economies of scale through the sharing of administrative support services with TEP and UNS Electric. The Company's revolving credit facility, which is shared with UNS Electric, was also refinanced in 2006 with a resulting decrease to the interest rate applicable to borrowings under that facility.

Q. How does UNS Gas' financial condition compare with other gas distribution utilities?

A. In terms of capital structure, the Company's 50% equity ratio at the end of the test year was in line with the industry average of 50.4% reported by Value Line for 2007. However, in terms of earnings and cash flow, UNS Gas is lagging most firms in the industry by a wide margin. The following table highlights some of the key financial results recorded by UNS Gas in 2007, as well as forecasted results for calendar years 2008 and 2009 assuming that new rates are not implemented until December 2009:

($000s)	2007 Actual	2008 Forecast	2009 Forecast
Net Income	$3,994	$8,425	$7,639
Return on Average Equity	4.6%	8.9%	7.3%
Net Operating Cash Flow	$28,368	$5,891	$21,804
Adjusted Operating Cash Flow (1)	$19,448	$16,303	$16,773
Capital Expenditures (CAPEX)	$22,589	$22,636	$23,247
% CAPEX Funded Internally (2)	86%	72%	72%

Notes:
(1) Adjusted Operating Cash Flow = Net Operating Cash Flow – Change in PGA Balance – Charges Paid to Affiliates (recorded as financing cash flow in 2007).
(2) % CAPEX Funded Internally = Adjusted Operating Cash Flow / Capital Expenditures.

The Company's earned ROE, ranging from a low of 4.6% in 2007 to a high of 8.9% projected for 2008, is quite low when compared with industry average returns. On a composite basis, the average ROE reported by Value Line for the natural gas distribution industry ranged from 11.5% to 12.2% over the period 2005-2007. Even though the Company will have realized a full year of rate relief in 2008, and has already benefited from unusually cold weather in the first half of 2008, UNS Gas still expects to earn a return on equity capital that is significantly lower than its peers in the industry and lower than the 10.0% ROE authorized in its most recent rate case.

In terms of cash flow, when the effects of temporary over- and under-collections of PGA gas costs are removed, it is apparent from the table above that UNS Gas is unable to cover all of its capital expenditures with internal cash flow. While this situation is not unusual for a utility experiencing growth in its service area, the magnitude of the cash shortfall is unusual. As an industry, gas distribution utilities typically fund approximately 80% of their capital expenditures with internal cash flow *after dividends are paid to shareholders*. Although UNS Gas' internal cash flow is expected to fund approximately 70% of capital expenditures over 2008 and 2009, this level of funding assumes that *no dividends are paid* on shareholder capital. If UNS Gas were to pay dividends at a level commensurate with the industry average, which equates to approximately 60% of annual earnings, the internal funding of capital expenditures would drop to approximately 50%, a level far below industry norms that is indicative of weak internal cash flow and a continuing dependence on outside capital.

Q. Are the debt obligations of UNS Gas rated by any of the major credit rating agencies?

A. Yes, they are. At the request of the Company, Moody's Investors Service ("Moody's") initiated ratings on UNS Gas in October 2008. A copy of the initial ratings report is attached to my Direct Testimony as Exhibit KCG-1. As discussed in that report, the senior unsecured debt obligations of UNS Gas are rated Baa3.

Q. What is the significance of a Baa3 credit rating?

A. Baa3 is the lowest investment-grade credit rating assigned by Moody's, just one notch above the speculative-grade rating of Ba1. Since the cost and availability of credit are much improved for companies with investment-grade ratings relative to companies having speculative-grade ratings, the achievement of an investment-grade rating for UNS Gas was a very important milestone. The level of credit risk as defined by Moody's for

each rating category (B and higher) is summarized in the following table:

Rating	Definition
Aaa	Obligations are judged to be of the highest quality, with minimal credit risk.
Aa	Obligations are judged to be of high quality and subject to very low credit risk.
A	Obligations are considered upper-medium grade and are subject to low credit risk.
Baa	Obligations are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.
Ba	Obligations are judged to have speculative elements and are subject to substantial credit risk.
B	Obligations are considered speculative and are subject to high credit risk.

It should also be noted that with the exception of the Aaa rating, Moody's appends a numerical modifier of 1, 2 or 3 to each of these rating categories. The modifier "1"indicates that the obligation ranks in the higher end of its generic rating category; the modifier "2" indicates a mid-range ranking; and the modifier "3" indicates a ranking in the lower end of that generic rating category. Hence, the Baa3 rating assigned to UNS Gas is considered to be the lowest investment-grade rating assigned by Moody's.

Q. Why is the achievement and maintenance of an investment-grade credit rating important to the Company and its customers?

A. An investment-grade credit rating is important for two reasons. First, it helps to ensure that capital can be raised on reasonable terms even during periods of stress in the financial markets. During periods of financial stress, when investor risk aversion is at its highest, many companies with speculative-grade credit ratings will either be shut out of the credit markets or will be forced to pay extremely high rates of interest on new

borrowings. Even in good times, investment-grade borrowers still enjoy a significant discount on their borrowing costs relative to speculative-grade borrowers. For utilities, this cost differential is ultimately saved in the rates paid by customers. Secondly, an investment-grade credit rating is also important in obtaining trade credit from gas suppliers and other vendors that UNS Gas does business with. The maintenance of adequate trade credit is essential to the Company's natural gas procurement program and the purchasing of other goods and services needed to provide retail gas service. Without such credit, it would be difficult, if not impossible, for the Company to lock-in purchases of natural gas in the forward markets as it does today. Over time such forward purchases help to stabilize the cost of gas supplied to and paid for by customers of UNS Gas.

III. CAPITAL STRUCTURE.

Q. Please describe the capital structure for UNS Gas as of the end of the test-year.

A. The capital structure for UNS Gas as of June 30, 2008 consisted of $100 million principal amount of long-term debt and approximately $99 million of common equity. After adjusting for unamortized issuance expenses, the long-term debt balance as of June 30, 2008 was $99.3 million. As reflected in the following table, long-term debt and common equity each comprised approximately 50% of total capital:

($ Thousands)	6/30/08	% of Total
Long-Term Debt	$99,265	50.01%
Common Equity	99,242	49.99%
Total Capital	$198,507	100.00%

Q. Do you recommend using the actual test-year capital structure for rate setting purposes?

A. Yes, I do. A capital structure consisting of a 50/50 mix of debt and equity capital is in line

with the industry average and is consistent with the capital structure adopted by the Commission in the Company's most recent rate case. Additionally, this level of equity will also support UNS Gas' efforts to maintain its investment-grade credit rating.

Q. What capital structure was adopted by the Commission in the Company's last rate case?

A. In Decision No. 70011 (November 27, 2007), the Commission approved rates for UNS Gas that incorporated a capital structure consisting of 50.0% common equity and 50.0% long-term debt.

IV. COST OF COMMON EQUITY CAPITAL.

Q. Please describe the approach used in estimating the cost of equity for UNS Gas.

A. The first step was to estimate the cost of equity for a group of publicly-traded companies engaged in the gas distribution business. This estimate, expressed as a range of values, was developed using the discounted cash flow approach ("DCF"), the capital asset pricing model ("CAPM"), and a bond yield plus risk premium approach based on the historical relationship between public utility bond yields and allowed returns on equity for gas utilities. We then examined the risk profile of UNS Gas relative to the comparable company group in order to determine an appropriate point estimate for the Company's cost of equity.

Q. Given the extreme volatility recently experienced in the capital markets and short-term money markets, is it possible to provide a reliable estimate for the cost of equity capital?

A. Yes, it is. However, great care must be exercised in selecting appropriate time periods for analysis and appropriate benchmark data. Additional time must also be devoted to the

interpretation and weighting of the results obtained from each model. It should be recognized that the cost of equity capital will change over time as markets react to changes in the global and domestic economies, changes in investor risk aversion and other factors affecting the specific industry or company being examined.

Q. What time period did you select for your analysis?

A. We focused our attention on capital markets data from the month of August 2008. Information from this time period was emphasized because (i) it was relatively recent, (ii) it followed an earlier run-up and subsequent decline in commodity prices and inflation expectations and (iii) it preceded the financial market turmoil and substantial flight-to-quality that occurred in September 2008. We also examined longer-term trends and changes in financial benchmark data over longer time periods in order to make an informed judgment regarding the cost of equity capital. However, in light of the unprecedented level of volatility experienced in the capital markets over the past eighteen months, we decided to draw most of our capital markets data from August 2008, a period of relative stability in the financial markets.

A. <u>Comparable Company Group.</u>

Q. Why did you analyze a group of comparable companies in order to estimate the cost of equity capital for UNS Gas?

A. Reliance on a comparable company analysis is important because UNS Gas does not have publicly traded equity securities. Additionally, the assets of UniSource Energy, the ultimate parent company of UNS Gas, are heavily weighted toward the electric utility industry. Although the risk profiles of electric distribution and gas distribution utilities are similar, TEP, the largest subsidiary of UniSource Energy, has a significant investment in electric generating facilities. As a consequence, the cost of equity capital for

UniSource Energy may not be representative of the cost of equity capital for UNS Gas. And because we are ascertaining the cost of equity capital for UNS Gas – not UniSource Energy – using a comparable company group composed of companies with significant distribution gas operations is appropriate.

Q. What criteria did you employ in selecting companies for the comparable company analysis?

A. As a starting point we evaluated each of the companies included in the natural gas distribution industry by Value Line Investment Survey ("Value Line"). From this group of eleven companies we selected ten companies that met the following screening criteria:

(i) More than 55% of operating revenues derived from gas operations (median value for group was 90%),

(ii) More than 50% of total gas throughput derived from distribution operations (median value for group was 100%),

(iii) No significant ownership of electric generating capacity,

(iv) No pending mergers or acquisitions of any significance, and

(v) Common stock currently paying a dividend, which is the normal practice for gas distribution utilities (median dividend payout for group was 63% of earnings).

Exhibit KCG-2 provides summary information on each of the companies that were selected based on these criteria. Although each of these companies may have unique circumstances that would differentiate them from UNS Gas, as a group, these companies have operating and financial characteristics as similar as possible to those of UNS Gas. The extent of this similarity is discussed further in Section IV.F below.

B. Application of Discounted Cash Flow Model ("DCF") Model.

Q. Please explain the DCF methodology.

A. The DCF methodology is derived from the Gordon dividend growth model. In its original form, the Gordon growth model may be used as a tool for determining the value of a share of common stock. The theory holds that the price of a share is equal to the present value of all future dividends. It is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1 + k_1)^1} + \frac{D_2}{(1 + k_2)^2} + \ldots + \frac{D_n}{(1 + k_n)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
k_n = Investors required rate of return in each year
n = One to infinity

If the dividends are assumed to grow at a constant rate "g" into the future, the required rate of return "k" is assumed to be constant from year to year, and "k" is greater than "g", then the equation above reduces to the following form as "n" approaches infinity:

$$P_0 = \frac{D_1}{(k - g)}$$

For purposes of estimating the cost of common equity capital, the equation above may be rearranged to solve for the investor's required rate of return:

$$k = \frac{D_1}{P_0} + g$$

Essentially, the constant growth DCF model recognizes that the return to the stockholder consists of two parts: dividend yield and growth. Equity investors expect to receive a

portion of their total required return in the form of current dividends and the remainder through price appreciation. Unfortunately, the constant growth DCF model cannot be applied to companies having expected near-term growth rates that are significantly higher or lower than their long-term growth potential. In these situations, it is usually necessary to apply a multi-stage DCF model which incorporates the various growth rates expected over time.

Q. Please describe the multi-stage DCF model.

A. If the Gordon dividend growth model is modified to reflect the expected future price of the stock in terminal year "n", and assuming that the investor's required rate of return "k" is constant, the current value of a stock may be derived from the following equation:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
P_n = Expected share price in year "n"
n = Year of expected share price

If the expected growth rate "g" is constant beyond year "n", the expected value of "P_n" can be obtained from the constant growth DCF model:

$$Pn = \frac{Dn\,(1+g)}{(k-g)}$$

Substituting this equation for "P_n" in the modified Gordon growth model, the following multi-stage DCF equation is obtained:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n} + \frac{D_n\,(1+g)}{(k-g)\,(1+k)^n}$$

Using this equation, the current share price, and the expected values for D_1 through D_n and "g", the required rate of return "k" may be calculated using an iterative solution process. The discount rate "k" which equates the current share price with the present value of future expected dividends represents the investor's required rate of return.

Q. How did you determine near-term dividend growth rates for each of the comparable companies?

A. We relied on estimates of future dividends and earnings growth published by Value Line, Zacks Investment Research ("Zacks") and SNL Financial ("SNL"). These estimates are all widely available in the investment community and are superior to estimates based solely on historical trend analysis. Published estimates are inherently forward looking, and presumably take into account historical financial trends for each company as well as any future threats and opportunities.

Q. What specific growth rates did you select for each company?

A. Exhibit KCG-3 provides the range of growth estimates for each company, as well as the five-year growth rate selected for use in the multi-stage DCF model. The growth rates from Value Line were derived using the published point estimates for dividends per share ("DPS") and earnings per share ("EPS") for the 2011-2013 timeframe. The five-year EPS projections from Zacks and SNL represent the median or "consensus" growth estimates as determined through surveys of stock research analysts. Differences between these published growth rates for any given company may be expected due to differences in the scope and timing of the surveys conducted. For purposes of selecting a five-year dividend growth rate, we relied on an average of the DPS and EPS growth rates from all three sources. Because analyst estimates for EPS growth are often influential in estimating future dividend growth, we believe that the growth rates selected for each company are representative of investor expectations.

Q. How did you calculate the expected first year dividend (D_1) for each company?

A. Exhibit KCG-4 shows the current quarterly dividend for each company, the five-year DCF growth rate for each company, and the projected quarterly dividends over the next four quarters. Projected quarterly dividends were increased from current levels based on each company's historical timing for dividend changes. The size of each projected dividend change was based on the five-year DCF growth rate. The expected first year dividend (D_1) was then derived by adding the projected quarterly dividends over the next four quarters.

Q. How did you determine the expected long-term growth rates to be used in the DCF model?

A. We considered two key factors that would likely have a significant influence on long-term investor expectations. One factor considered was the prospect for long-term growth in the U.S. economy as a whole. The second factor considered was the prospect for growth over the next five years for the gas utility industry as a whole.

Q. What are the prospects for growth in the gas utility industry as a whole over the next five years?

A. Based on the growth rates published for the comparable company group, which are shown in Exhibit KCG-3, the median expected earnings growth rate for this group ranges from 5.3% to 7.0% depending on the source of data selected. Additionally, in August 2008, Zacks published an industry-wide consensus growth rate of 8.6% for the gas utility industry. Although these earnings estimates cover only a five-year time period, it is reasonable to conclude that investors would take such growth rate expectations into account in assessing the long-term growth rate potential for the industry.

Q. Why is it also necessary to consider the long-term growth prospects for the U.S. economy as a whole when evaluating long-term growth prospects for the industry?

A. Since published growth rates for individual companies and specific industries typically do not extend beyond five years, these growth rate estimates may be significantly influenced by short-term economic factors that are not expected to last in perpetuity. Additionally, as domestic providers of a basic utility service, it is reasonable to assume that the gas distribution industry would have growth prospects that are closely linked to the long-term growth rate of the U.S. economy.

Q. How did you arrive at an estimate of long-term growth for the U.S. economy?

A. Real economic growth in the United States has been remarkably consistent over long periods of time, averaging 3.4% per year from 1929 through 2007, as well as for the post-war period of 1947 through 2007. Although economic growth as measured by gross domestic product ("GDP") can vary significantly over short time periods, the historical growth rate of 3.4% in real GDP has occurred over numerous business cycles, and during extended periods of war and peace. As such, it is reasonable to conclude that investors would expect a similar growth rate in real GDP over the long-run.

In order to derive an estimate of *nominal* GDP growth, it is necessary to add a long-term estimate of expected inflation to the growth in *real* GDP. Expectations for long-term inflation can be calculated by subtracting the yield on long-term U.S. Treasury inflation-protected securities ("TIPS") from the yield-to-maturity on long-term fixed-rate U.S. Treasury securities. However, based on research published by the Federal Reserve Bank of Cleveland, adjustments to these differences in nominal yields are often required in order to derive a more accurate estimate of inflation expectations. These adjustments, which are published on a regular basis by the Federal Reserve Bank of Cleveland, are intended to compensate for the liquidity price premium paid by investors for fixed-rate

Treasury securities and for the inflation risk price premium paid for TIPS securities, two factors which can bias the results obtained from a simple comparison of nominal yields. The impact of these premium adjustments can be seen Exhibit KCG-5, which contains published nominal yield differences for 10-year and 20-year Treasury securities over the past two years, as well as the yield difference on a premium-adjusted basis for 10-year Treasury securities. As depicted in that exhibit, inflation expectations derived from a nominal yield comparison understated the values derived from a premium-adjusted approach by a wide margin from late 2007 through August 2008. Additionally, this exhibit also shows that the implied rate of inflation on a premium-adjusted basis has exceeded 3.0% for much of 2008 before falling to approximately 2.9% in August 2008. When the August 2008 estimate of 2.9% for expected inflation is added to the expected growth in real GDP of 3.4% discussed above, a long-term *nominal* growth rate of 6.3% is obtained for the U.S. economy as a whole.

Q. What is a reasonable estimate of expected long-term growth for the gas distribution industry?

A. An annual growth rate of 6.3% represents a reasonable estimate of investor expectations for earnings and dividend growth over the long-run. This value is consistent with expectations for long-term growth in the U.S. economy as well as published growth rates for the natural gas industry over the next five years.

Q. Did you adjust the expected industry growth rate to arrive at company-specific long-term growth rates?

A. No. Since the gas distribution industry remains heavily regulated, and is fairly homogeneous in terms of business practices and capital investment, the long-term growth rate for each of the comparable companies was assumed to revert to the mean or expected long-term growth rate for the industry. Reversion to the industry mean is a widely-

practiced method of forecasting the long-term financial performance of companies in a mature industry like gas distribution.

Q. How did you determine the current stock price for each company?

A. A simple average of the daily closing price was calculated for the month of August 2008, adjusted on an ex-dividend basis for any dividends paid during this period.

Q. What results did you obtain from the multi-stage DCF model?

A. Exhibit KCG-6 summarizes the results obtained, as well as each of the input variables used in the multi-stage DCF calculations. The estimated cost of equity for each company fell within a range of 9.5% to 11.2%. The average value for the sample group was 10.1%.

C. <u>Application of Capital Asset Pricing Model ("CAPM").</u>

Q. Please describe the capital asset pricing model.

A. The CAPM was developed using modern portfolio theory, which is premised on the assumption that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. Defining investment risk as the variability of expected future returns, the CAPM further assumes that risk is comprised of two components: systematic risk and unsystematic risk. Systematic risk is unavoidable, and is tied to macroeconomic factors that affect all companies. Unsystematic risk is company-specific, and theoretically can be eliminated through portfolio diversification. As such, the CAPM holds that investors should only be compensated for systematic risk. Mathematically, the CAPM is expressed as follows:

$$k_s = r_f + B_s \times (k_m - r_f)$$

Where: k_s = expected return on stock "s"
r_f = expected risk-free rate of return
B_s = beta for stock "s"
k_m = expected return on overall stock market

As a measure of systematic risk, the "beta" coefficient measures the extent to which returns on a given stock are correlated with returns on the overall market. Historical values for beta can be determined statistically by comparing total returns on a stock to the total returns on a market index. The risk-free rate of return "r_f" is typically estimated using the yield-to-maturity ("YTM") on U.S. Treasury securities. For common stocks, which have no defined maturity date, the YTM on long-dated Treasury bonds should be used as the risk-free rate. The difference between the expected market return and the risk-free rate, shown above as ($k_m - r_f$), is frequently referred to as the market risk premium. Estimates for the market risk premium are typically derived by examining historical rates of return for common stocks and U.S. Treasury securities over long periods of time. The time series data in the SBBI yearbook published by Morningstar is a commonly used reference for historical return and risk premium data. Using expected values for the market risk premium, beta, and the risk-free rate, the CAPM can be used to estimate the expected rate of return (or cost of equity) for any given stock.

Q. How did you determine expected values for the market risk premium, beta, and the risk-free rate?

A. Using the Morningstar SBBI time series data, we selected the historical market risk premium for the period 1926-2007 as a proxy for the expected market risk premium. This value, 7.1%, represents the difference between the average realized return on large company stocks (12.3%) and the average realized return on 20-year U.S. Treasury bonds (5.2%) over this period. For the risk-free rate we selected the YTM on 20-year U.S.

Treasury bonds. The beta for each company represents the published estimate from Value Line.

Q. What results did you obtain from the CAPM?

A. Exhibit KCG-7 summarizes the results obtained using the average risk-free rate of 4.53% from August of 2008. As may be seen, the estimated cost of equity for each company fell within a range of 10.2% to 11.3%. The average value for the sample group was 10.7%.

D. <u>Application of Bond Yield plus Risk Premium Approach.</u>

Q. Please describe this approach to estimating the cost of equity capital.

A. This method relies upon the well established relationship between risk and required rates of return. Rational investors will naturally demand higher expected rates of return on investments that entail a greater risk of loss. This phenomenon can be readily observed in the bond markets, where investors demand a significantly lower interest rate (or yield-to-maturity) on U.S. Treasury bonds relative to an investment in corporate bonds which entail more risk. The size of this difference in required rates of return, which is commonly referred to as a risk premium, can vary significantly over time as changes occur in the capital markets and as investors' appetite for risk expands and contracts. This same concept can also be extended to investments in common stocks, which are inherently more risky than investments in either U.S. Treasury bonds or high quality corporate bonds. By adding an incremental risk premium to observed bond yields, an estimate can be made for the required rate of return on a common stock investment (i.e., the cost of equity capital for that stock).

Q. Why have you included this third approach to estimating the cost of equity, when the DCF approach and the CAPM have traditionally been assigned more weight by the Commission in utility rate proceedings?

A. During times of turbulence in the financial markets, it is better to use more approaches (rather than fewer) in order to validate the results obtained from the more traditional DCF and CAPM approaches. Additionally, while the CAPM is also a risk premium approach, it is fundamentally different in that it relies heavily on modern portfolio theory and the importance of the "beta" coefficient to investors. By contrast, the bond yield plus risk premium approach is based on a more intuitive and straightforward interpretation of the risk/return relationship.

Q. What are the bond markets signaling with respect to required risk premiums?

A. Risk premiums in the bond markets have increased considerably since mid-2007, indicating a significant contraction in investors' appetite for risk. Exhibit KCG-8 shows the required rate of return or yield-to-maturity ("YTM") on 30-year U.S. Treasury bonds and long-term public utility bonds. The required YTM on public utility bonds in this exhibit is based on an index of investment-grade utility bonds tracked and published by Mergent Bond Record. As may be seen, the required YTM on the 30-year U.S. Treasury bond has fallen since mid-2007 whereas the required YTM on public utility bonds has increased. As may be seen in Exhibit KCG-9, the spread between these required rates of return, otherwise known as a credit spread or credit risk premium, widened from approximately 110 basis points (or 1.1 percent) in early 2007 to approximately 200 basis points (or 2.0 percent) by August 2008. Due to a resurgence of turmoil in the capital markets in September 2008, credit spreads have widened even further since that time, indicating a significant contraction in investors' appetite for risk.

Q. What methods exist for estimating the incremental risk premium required by investors for an investment in common stock?

A. There are many possible approaches, most of which rely on establishing a historical relationship between the cost of equity capital and the required YTM on bonds. The cost of equity capital may be estimated at various points in time by using the DCF and CAPM approaches discussed previously. Alternatively, the allowed returns on equity contained in utility rate orders may also be used as a proxy for the cost of equity capital over time. We have used this latter approach in our analysis since the allowed ROEs contained in utility rate orders are both readily observable and provide a large data set for analytical purposes.

Q. What has been the recent trend in allowed ROEs?

A. Allowed ROEs for regulated utilities have gradually moved lower over the past five years. This trend can be seen in Exhibit KCG-10, which plots the allowed ROEs contained in utility rate orders for domestic gas distribution utilities. The data in Exhibit KCG-10 was taken from reports published by Regulatory Research Associates, a division of SNL Financial that closely monitors utility rate decisions for the investment community.

Q. How do these allowed ROEs compare with the required rates of return on public utility bonds over time?

A. From 2003 through mid-2007 most gas utilities received allowed ROEs that were approximately 3.5% to 5.5% higher than prevailing public utility bond yields at the time the rate orders were issued. As may be seen in Exhibit KCG-11, however, this range of implied equity risk premiums has drifted lower by approximately 0.5% since mid-2007. This downward shift is understandable in light of the regulatory lag inherent in the utility rate-setting process and the increase in public utility bond yields that has occurred since

mid-2007. Since public utility bond yields and credit spread risk premiums were likely much lower when these rate cases were originally filed, as opposed to when they were finally decided, it is logical to expect a temporary reduction in the observed difference between allowed ROEs and prevailing public utility bond yields.

Q. What level of equity risk premium is appropriate for use in estimating the cost of equity for gas distribution utilities?

A. Based on the information presented in KCG-11, we selected a range of 3.75% to 5.0% for purposes of estimating the cost of equity capital. This range is based on the average value observed over the period from 2003 through August 2008, plus or minus one standard deviation, a commonly used statistical measure of central tendency.

Q. What is the resulting estimate for the cost of equity capital for gas distribution utilities?

A. Adding the estimated equity risk premium of 3.75% to 5.0% to the average YTM on public utility bonds of 6.48% observed for month of August 2008 results in an estimated cost of equity of approximately 10.2% to 11.5%.

E. <u>Cost of Equity for Comparable Companies</u>.

Q. What conclusions have you reached regarding the cost of equity for the comparable company group?

A. As may be seen in the table below, the range of overlapping values obtained from all three approaches (DCF, CAPM and bond yield plus risk premium) is 10.2% to 11.2%. Recognizing that each methodology has its own strengths and weaknesses, and recognizing that cost of equity analysis is not an exact science, we have selected this range of overlapping values as our estimate of the cost of equity for the comparable

company group. The low end of this range represents the minimum value obtained from both the CAPM and the bond yield plus risk premium approach, while the high end of this range represents the high value obtained from the DCF analysis.

Summary of Comparable Company Analysis

	DCF Model	CAPM	Risk Premium	Conclusion
Low end of range	9.5%	10.2%	10.2%	10.2%
High end of range	11.2%	11.3%	11.5%	11.2%

F. Cost of Equity for UNS Gas.

Q. How did you determine the cost of equity for UNS Gas?

A. This is best accomplished by comparing the risk profile of UNS Gas to that of the comparable company group and selecting an appropriate point estimate based on the well established relationship between risk and expected return.

Q. How does the risk profile of UNS Gas differ from that of the comparable company group?

A. Relative to an investment in the group of comparable companies, an equity investment in UNS Gas is decidedly riskier. First, UNS Gas is much smaller than any of the comparable companies, thereby limiting the Company's ability to withstand financial shocks arising from unforeseen events. As indicated in Exhibit KCG-2, the smallest company in the comparable company group had a market capitalization of nearly $1 billion as of August 2008. Second, all of the companies in the comparable company group provide a current return to their shareholders in the form of a dividend, something that UNS Gas has not been able to do since the Company's inception in 2003. Third,

while the Company's senior unsecured debt obligations were recently assigned an investment-grade credit rating of Baa3, this rating is at the low end of the credit ratings enjoyed by companies in the comparable company group. As may be seen in Exhibit KCG-2, the median issuer rating for the comparable company group is "A" from Standard & Poor's, "A3/Baa1" from Moody's and A- from Fitch. Consequently, it is reasonable to conclude that the cost of capital (both debt and equity) would be higher for UNS Gas relative to the comparable company group. As may be seen Exhibit KCG-12, investors require a higher rate of return (or YTM) on Baa-rated public utility bonds relative to A-rated public utility bonds. As of August 2008, this credit spread risk premium was approximately 60 basis points (or 0.6%). Since common stock investments are inherently riskier than investment-grade bond investments, this observed risk premium from the bond market can be used as an estimate of the *minimum* equity risk premium required by equity investors in a Baa-rated public utility relative to an A-rated public utility.

Q. What is your estimate of the cost of equity capital for UNS Gas?

A. In light of the risk factors cited above, as well as the credit spread and equity risk premiums applicable to lower-rated utilities, it is reasonable to conclude that the cost of equity for UNS Gas is near the high end of the range established for the comparable company group. As such, a reasonable point estimate for UNS Gas is 11.0%.

Q. Are you recommending an allowed ROE equal to the cost of equity for UNS Gas?

A. Yes I am, assuming that UNS Gas is provided with an opportunity to actually earn something close to its 11.0% cost of equity capital. An allowed ROE of 11.0% is fair to both the Company and its customers based on the analysis presented above. This level of return should also be sufficient to support the financial integrity of UNS Gas, so long as other key aspects of the Company's rate request are granted.

V. COST OF DEBT CAPITAL.

Q. What was UNS Gas' embedded cost of debt for the test-year?

A. As shown on Schedule D-2 of the Company's Application, the weighted average cost of debt for UNS Gas was 6.49% as of the end of the test-year.

Q. What cost of debt do you recommend in this case?

A. I recommend use of the 6.49% cost at the end of the test-year. This cost reflects the interest rate of 6.23% on the two long-term notes issued by UNS Gas in 2003, the amortization of related debt issuance costs, and 50% of the issuance cost amortization and commitment fees on the joint revolving credit facility shared with UNS Electric. Although UNS Gas had no borrowings outstanding on the revolving credit facility at the end of the test-year, maintenance of this facility is critical for purposes of funding seasonal working capital needs and future PGA bank balances, as well as funding a portion of capital expenditures. As such, it is appropriate to reflect the annual fixed cost of this facility in the cost of debt for UNS Gas.

VI. WEIGHTED AVERAGE COST OF CAPITAL.

Q. Please summarize your findings regarding the weighted average cost of capital for UNS Gas.

A. Based on the recommended capital structure, the proposed cost of debt, and UNS Gas' cost of equity capital, I recommend the Commission adopt a WACC of 8.75%, calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Long-Term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	11.00%	5.50%
Total	100.00%		8.75%

VII. ABILITY OF UNS GAS TO EARN ITS COST OF CAPITAL.

Q. Will the rate increase requested by UNS Gas provide the Company with an opportunity to actually earn its cost of capital?

A. Yes, I believe it will.

Q. Have you prepared any financial projections that show the impact of the Company's rate request on UNS Gas' earnings?

A. Yes. The following table summarizes the Company's forecast of net income and earned ROE through 2011 assuming that UNS Gas is granted its full rate request and is allowed to implement new rates in December 2009:

($ Thousands)	2008	2009	2010	2011
Gross Margin	$57,388	$58,966	$69,196	$71,115
Operating Expenses	(37,127)	(40,079)	(42,099)	(44,122)
Operating Income	$20,262	$18,887	$27,097	$26,994
Other Income – Net	255	230	224	743
Interest Expense	(6,552)	(6,467)	(6,504)	(6,910)
Pre-Tax Income	$13,964	$12,651	$20,817	$20,826
Income Tax Exp.	(5,539)	(5,012)	(8,247)	(8,250)
Net Income	$8,425	$7,639	$12,571	$12,576
Ending Common Equity	$101,063	$108,703	$121,273	$133,849
Return on Avg. Equity	8.9%	7.3%	10.9%	9.9%

Q. Does this forecast represent the best estimate of earnings available at this point in time?

A. Yes, it does. Although this forecast relies on numerous key assumptions regarding future sales levels, operating expenses, interest rates, tax rates and capital expenditures, it represents management's best estimate at this point in time. I would also note that a very similar forecast was provided to Moody's as part of the credit rating review process for UNS Gas. The only difference between that forecast and the one summarized in the table above relates to the requested level of rate relief, a value that had to be estimated at the time the forecast was provided to Moody's.

Q. Why is it important to provide the Company an opportunity to earn its allowed ROE?

A. If UNS Gas is not allowed to earn its cost of equity capital, there will be little incentive for UniSource Energy to increase its equity investment in UNS Gas through the continued retention of earnings at UNS Gas and through new contributions of capital.

Without this source of capital, UNS Gas would become more dependent on debt capital to fund its capital expenditures, thereby putting further pressure on the Company's creditworthiness. As discussed previously, maintenance of the Company's creditworthiness is essential to the Company's gas procurement program and the ability of UNS Gas to obtain new capital on reasonable terms. Additionally, UNS Gas would likely be forced to file a series of back-to-back rate cases over the next several years in order to improve its earnings and cash flow. Such a scenario would add additional costs to the Company, its customers and the Commission that could otherwise be avoided through a more constructive, and longer-term, approach to rate making.

In addition to these practical considerations, the financial performance of UNS Gas is also relevant to the setting of just and reasonable rates as described in two key U.S. Supreme Court rulings. In a 1923 ruling involving *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), the Supreme Court stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

The Bluefield decision established financial integrity and capital attraction as standards to be met in setting the rate of return for a public utility. In a 1944 decision, *Federal Power Comm'n v. Hope Natural Gas,* 320 U.S. 591 (1944), the Supreme Court stated:

> The return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.

The Hope decision reinforced the standards of financial integrity and capital attraction, and further established the standard of setting a return on equity that is commensurate with the risks faced by the equity investor.

The Hope and Bluefield decisions call into question the legality of any regulatory practice that repeatedly denies a public utility an opportunity to earn a reasonable ROR on its invested capital. Although I am not an attorney, the concept of requiring a return to be "reasonably sufficient" and "commensurate with the returns on investments in other enterprises having corresponding risks" is easy to grasp and difficult to argue with.

VIII. RATE OF RETURN ON FAIR VALUE RATE BASE.

Q. What ROR do you recommend be applied to the Company's FVRB?

A. I recommend that a ROR of 6.80% be applied to the FVRB, even though I believe, as discussed below, that UNS Gas could justify a ROR of 7.30%. The primary reason to forego the full 7.30% is to mitigate the rate impact on our customers in these challenging economic times.

Q. How did you arrive at this value?

A. This ROR, when applied to the Company's FVRB of approximately $256 million, produces an overall rate increase that would provide UNS Gas with a reasonable opportunity to actually earn its cost of capital, to support its creditworthiness and to attract capital on reasonable terms.

Q. How does this ROR compare with the value that would be obtained from the methodology adopted by the Commission in Decision No. 70441 involving Chaparral City Water Company ("Chaparral") and the revised methodology subsequently recommended by the Commission Staff?

A. The ROR requested by UNS Gas is lower. If the approach adopted by the Commission in Decision No. 70441 is applied to the Company's 8.75% WACC (see Section VI of my Direct Testimony) with an estimated inflation rate of 2.9% (see Section IV.B. of my Direct Testimony), the resulting ROR on FVRB would be 7.30%. Likewise, this same value of 7.30% would be obtained from the revised methodology being recommended by the Commission Staff in the current Chaparral rate proceeding (Docket No. W-02113A-07-0551).

Q. Please explain how a ROR value of 7.30% would be obtained using either approach.

A. Certainly. With respect to the approach adopted in Decision No. 70441, where the ROR on FVRB was derived by adjusting the cost of equity downward by the expected rate of inflation, the following result would be obtained for UNS Gas using a 2.9% rate of inflation:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	8.10%	4.05%
Total	100.00%		7.30%

* Note: Modified cost of equity = 11.0% - 2.9% = 8.1%.

Staff's revised methodology, which is explained in the Direct Testimony of Gordon L. Fox, dated October 3, 2008, in Docket No. W-02113A-07-0551, employs a slightly different inflation rate adjustment. Instead of adjusting only the cost of equity by the full rate of inflation, the modified approach adopted by Mr. Fox adjusts both the cost of debt and cost of equity by one-half of the expected rate of inflation. Using the 2.9% expected rate of inflation discussed earlier in my testimony, the following result would be obtained for UNS Gas:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	50.01%	5.04%	2.53%
Common Equity	49.99%	9.55%	4.77%
Total	100.00%		7.30%

* Note: Modified cost of debt = 6.49% - 1.45% = 5.04%.
Modified cost of equity = 11.0% - 1.45% = 9.55%.

Q. In the Arizona Court of Appeals ruling that led to Commission Decision No. 70441, did the Court specify any particular method for the determination of an appropriate ROR on FVRB?

A. No. My non-legal understanding of that decision, dated February 13, 2007, is that the Court of Appeals found that the Commission has wide latitude in setting the ROR on FVRB. Although the Court found the method used in the original Chaparral Decision to be unconstitutional, no particular method of determining the ROR on FVRB was specified by the Court.

Q. Why is UNS Gas requesting a ROR on FVRB that is lower than would be obtained through other methods that have been approved by the Commission and recommended by the Commission Staff?

A. There are several reasons. First, it appears that the Commission has wide discretion in setting the ROR on FVRB, provided that fair value is adequately considered in the rate setting process. Second, the Company believes that the requested ROR, when applied to the proposed FVRB, will be sufficient to provide UNS Gas with an opportunity to earn its cost of capital and to attract new capital on reasonable terms. Third, in light of the current economic environment, the Company would like to limit the impact of its rate request on customers. Under these circumstances, it appears that the public interest would be best served if the Commission were to use its discretion in setting a ROR on FVRB that gives UNS Gas an opportunity to earn its cost of capital while at the same time limiting the impact on customers.

IX. CARRYING COST ON PURCHASED GAS ADJUSTOR BALANCE.

Q. What is the current carrying cost applicable to PGA balances carried by UNS Gas?

A. The current rate applicable to PGA balances, whether they are in an over- or under-

recovered position, is the 3-month Financial Commercial Paper rate as published in the Federal Reserve Statistical Release H.15.

Q. Does this rate reflect the actual cost to UNS Gas of financing PGA cost deferrals?

A. No. Under the joint revolving credit facility shared with UNS Electric, UNS Gas may borrow at a rate of LIBOR plus 1.0%. This rate is typically much higher than the interest rate on commercial paper issued by large creditworthy financial institutions. As may be seen in Exhibit KCG-13, financial commercial paper rates and LIBOR tracked very closely to one another through mid-2007. However, since that time, rates on 3-month LIBOR borrowings have been significantly more expensive than rates on 3-month financial commercial paper. When the additional 1.0% credit margin is added to LIBOR to reflect the cost of short-term borrowing to UNS Gas, it is readily apparent that the financial commercial paper rate is not adequate in terms of providing full cost recovery to UNS Gas.

Q. What carrying cost do you recommend be applied to the Company's PGA balances?

A. I recommend use of the 3-month LIBOR rate as published by the ~~Federal Reserve~~ Wall Street Journal, plus 1.0% to cover the additional margin that UNS Gas must pay for short-term borrowings.

Q. Is the Company recommending any other modification to the PGA mechanism adopted by the Commission in Decision No. 70011?

A. No.

X. SUMMARY OF SCHEDULES.

A. Schedules A-3 and A-4.

Q. Please describe the information contained in Schedules A-3 and A-4.

A. Schedule A-3 presents a summary of the capital structure, capital ratios and weighted cost of capital for the years ending December 31, 2006 and December 31, 2007, and the test-year ending June 30, 2008. Schedule A-3 also presents similar information on a forecasted basis for the twelve months ending June 30, 2009.

Schedule A-4 provides historical and projected information relating to construction expenditures, net plant in service and gross utility plant in service. The projected information for the period 2009-2011 is consistent with the base case financial forecast discussed elsewhere in my Direct Testimony. The values for net plant in service and gross utility plant are presented on a regulatory accounting basis, which differs slightly from the presentation used in the Company's audited financial statements and the financial forecast.

B. Schedules D-1 through D-4.

Q. Please describe Schedule D in the Company's Application.

A. Schedule D consists of four parts, Schedules D-1 through D-4.

Schedule D-1 contains the Company's actual and proposed capital structure and weighted average cost of capital for the test-year ended June 30, 2008. This schedule also contains projected information pertaining to the Company's capital structure and weighted average cost of capital as of June 30, 2009.

Schedule D-2 contains detailed information on UNS Gas' cost of long-term debt. Schedule D-2, page 1, provides a calculation of the weighted average cost of long-term debt for the test-year ended June 30, 2008. Schedule D-2, page 2, contains a projection of the Company's cost of debt as of June 30, 2009.

Schedule D-3 indicates that UNS Gas had no preferred stock outstanding during the test-year, and that there are no plans to issue preferred stock.

Schedule D-4 contains the Company's estimated cost of equity capital and the proposed ROE for use in this proceeding.

C. <u>Schedules F-1 through F-4.</u>

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement and a return on common equity calculation for the test-year ended June 30, 2008. This same information is presented on a projected basis for the year ending June 30, 2009. Pursuant to Commission filing requirements, the projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of proposed rates as of July 1, 2008.

Schedule F-2 contains a summary cash flow statement for the test-year ended June 30, 2008. This same information is presented on a projected basis for the year ending June 30, 2009. The projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of

proposed rates as of July 1, 2008.

Schedule F-3 contains information on the Company's construction expenditures during the test-year ended June 30, 2008. This same information is presented on a projected basis for calendar years 2009, 2010 and 2011.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3.

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through June 30, 2009 were taken from a base case financial forecast prepared for UNS Gas, the same base case forecast discussed elsewhere in my Direct Testimony. It should be noted that this forecast is based on numerous assumptions regarding sales growth, natural gas prices, operating and capital expenditure levels, and other factors that are subject to change over time. Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rates beginning July 1, 2008. These additional projections are included for the purpose of complying with the Commission's rate filing requirements. Since it is unlikely the Company will be allowed to increase its rates prior to late 2009, projections assuming that the requested rates were implemented in July 2008 have limited analytical value.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

KCG-1

Credit Opinion: UNS Gas, Inc.

UNS Gas, Inc.

Tucson, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Senior Unsecured	Baa3
Ult Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

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Opinion

Corporate Profile

UNS Gas, Inc. (UNS Gas: Baa3 senior unsecured, stable outlook) is a local gas distribution utility serving approximately 146,000 retail customers in Mohave, Yavapai, Coconino and Navajo counties of northern Arizona and Santa Cruz County in southeastern Arizona. UNS Gas is a subsidiary of UniSource Energy Services (UES) which is also the parent of UNS Electric, Inc. (UNS Electric: Baa3 guaranteed revolving credit facility, stable outlook), a transmission and distribution utility serving approximately 90,000 retail customers in Mohave and Santa Cruz counties in Arizona. UES is a wholly owned subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility - security limited to stock of certain subsidiaries, stable outlook). UNS' largest subsidiary is Tucson Electric Power (TEP: Baa3 senior unsecured, stable outlook), a vertically integrated electric utility serving approximately 400,000 retail customers in the community of Tucson Arizona.

Recent Developments

On October 28, 2008, Moody's assigned a Baa3 rating to approximately $100 million of senior unsecured guaranteed notes (the Notes) of UNS Gas, Inc. and assigned a stable outlook. The Notes are guaranteed by UES.

In July and August 2008, Moody's assigned ratings of Baa3 to UNS Gas and UNS Electric's joint $60 million guaranteed credit facility, and to UNS Electric's $100 million senior unsecured guaranteed notes. The facility and the UNS Electric notes are also guaranteed by UES.

Rating Rationale

The Baa3 rating assigned to UNS Gas' senior unsecured notes reflects the interdependence that currently exists between the company and its affiliate UNS Electric as a result of their shared credit facility and parental guarantee from UES. The rating reflects our view of the consolidated credit quality of UES, which guarantees the debt of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric shared senior unsecured revolving credit facility, and the guaranteed senior unsecured notes of UNS Electric, are also rated Baa3. For additional information, please see July 8, 2008 press release and related July 9, 2008 credit opinion for UNS Gas/UNS Electric.

On a stand-alone basis, following the framework outlined in Moody's Rating Methodology for the North American Regulated Gas Distribution Industry (Local Gas Distribution Companies), (the LDC Methodology),UNS Gas' credit profile maps to a Baa2. The Methodology focuses on core factors including: degree of profitability, the level of regulatory support, degree of ring fencing, and financial strength and flexibility as evidenced by key financial metrics and liquidity.

We elaborate on the various key rating drivers for UNS Gas' mapped underlying Baa2 credit quality below:

Factor 1: Sustainable Profitability

UNS Gas' overall profitability, as measured by return on average common equity (ROE) and EBIT per customer, has been improving and currently maps to the low end of the range for investment grade issuers. Over the medium term, we expect these metrics to remain within the Baa range.

In 2006 and 2007, as earnings declined while equity increased due to incremental investment and earnings retention, UNS Gas' ROE was under 6%. In November 2007, UNS Gas received a $5 million rate increase with new rates effective December 2007. As a result, ROE, adjusted for Moody's standard adjustments, improved to approximately 7.7% on trailing twelve month basis as of June 30, 2008. This is within the range of 5-9% identified for Baa issuers, although still below the 10% ROE authorized by the ACC in its November order. Due to planned investments in its system significantly above depreciation, UNS Gas will likely need on-going rate relief with much less regulatory lag in order to maintain its ROE.

UNS Gas' EBIT/ Customer metric also currently maps to the lower end of the Baa range. The ratio declined modestly from 2005 through 2007 due to limited earnings growth without a rate case combined with above average customer growth. Due to general economic conditions, customer growth in 2007 declined to approximately 2%, which is lower than previous years. Growth in 2008 is expected to be less than 1%, and is expected to remain modest over the near-term. With customer growth slowing and the recent rate increase, the three year average metric may be able to move into the upper Baa range.

Factor 2: Regulatory Support

The regulatory supportiveness factor has been scored in the Ba range reflecting Moody's view of the traditionally challenging Arizona regulatory environment, where regulatory lag has historically been significant for both gas and electric utilities. The scoring also recognizes the existence of fuel and gas purchase adjustment mechanisms designed to shorten the time to recovery of these more volatile costs.

UNS Gas' last fully litigated rate case was resolved in approximately 16 months with new rates in place reflecting a historic test year that ended two years before the decision. This level of regulatory lag makes adequate and timely recovery difficult to achieve. UNS Gas did receive approximately 55% of its request though its ROE was lowered from its requested 11% to 10%. The ACC also rejected requests by UNS Gas to allow revenue decoupling and CWIP in rate base.

UNS Gas filed a new rate case in February 2008 requesting a $10 million rate increase (6.6%) premised on an 11% ROE and 50% equity ratio and using a September 2007 test year end. In March, ACC Staff informed UNS Gas that the test year did not meet the ACC's requirements for elapsed time since new rates from UNS Gas' prior rate case were implemented, and as such, the filing was viewed as deficient. UNS Gas plans to file a revised general rate case in the fourth quarter using a June 30, 2008 test year. Moody's expects further need for rate cases over the near-term due to regulatory lag and on-going capital expenditures.

Arizona gas utilities appear to have moderately well functioning fuel cost recovery mechanisms. UNS Gas' Purchased Gas Adjustor mechanism may be changed monthly based on a comparison of rolling twelve-month average gas cost and gas costs in base rates though there are limits to the levels of adjustments over a twelve month period. UNS Gas may also request a surcharge to recover deferred balances.

Factor 3: Ring Fencing

Ring-fencing at UNS Gas maps within the Baa criteria outlined in the LDC Methodology. Although the risk of exposure to non-regulated activities is considered quite modest as both UNS Gas and UNS Electric are fully regulated, there is significant interdependence between the UES subsidiaries in the form of a shared credit agreement and parental guarantees. Services are also shared with UniSource's primary regulated utility TEP. UNS Gas contributed approximately 50% of consolidated UES' EBIT and approximately 6% of UniSource's EBIT in 2007.

The Arizona Corporation Commission (ACC) has not restricted UNS Gas' ability to pay dividends to its parent; however, the utility has not paid a dividend over the last several years. There are dividend restrictions under the company's notes and credit agreement, but UNS Gas is well within the limits imposed by these documents.

Factor 4: Financial Strength and Flexibility

The four metrics that comprise Financial Strength and Flexibility fall within the mid Baa to low A range.

UNS Gas' retained cash flow to debt (RCF/Debt) has been within the 12-16% range since 2005, and may improve moderately over the near-term. UNS Gas is somewhat unique in that it has been allowed to retain 100% of its free cash flow over the last couple of years, which has significantly strengthened its financial profile. Using the LDC Methodology framework, which is based on three-year averages, UNS Gas' RCF / Debt ratio maps to a rating of Baa1. This metric may continue to improve, and potentially move to the low A range as UNS Gas continues to grow its rate base and seek ongoing rate relief.

UNS Gas' debt to capitalization (Debt/Cap) has improved from approximately 62% in 2004 to 52% at the end of 2007. Debt/Cap has improved as the utility reinvested its earnings to fund its capital expenditures without issuing new debt. UNS Gas' three year average Debt/Cap currently maps to a Baa1. As of June 30, 2008, Debt/Cap was 48.5%. A three-year average Debt/Cap in the range of 47% - 50% maps to a low A rating.

UNS Gas' EBIT to Interest ratio fell from 2004 through 2007 due to moderately rising interest and depreciation expenses and a lack of rate relief over that time. As a result, the metric maps to a low Baa rating for the average of 2005 through 2007. With the recent moderate rate relief, EBIT has improved and interest expense has levelized in 2008. EBIT to Interest improved to 2.7x for the twelve months ended June 30, 2008 and, over the medium term, it is projected to remain in the upper 2x levels. With further rate relief and cost control, the metric may improve to above 3x which would map to the A range.

The free cash flow to funds from operations (FCF/FFO) metric indicates the degree of flexibility (or shortfall) that a utility has available should there be significant, rapid changes in gas prices or if other unexpected liquidity needs arise. The measure is generally negative for most utilities indicating an on-going need for new financing. The metric has historically been fairly volatile for UNS Gas as it was (96%) in 2005, 17% in 2006 and (5%) in 2007. The FCF/FFO three-year average through year end 2007 maps to the low A range. Going forward, free cash flow is likely to stay modestly negative as cash from operations is expected to approximate capital expenditures while the utility continues to not pay any dividends over the near-term. As a result, FCF/FFO is projected to remain in the low A range.

Liquidity Profile

UNS Gas cash flow profile is relatively stable with operating cash flow approximately covering capital expenditures in 2006 and 2007. In 2007, cash from operations primarily covered capital expenditures of approximately $23 million. Over the near-term, capital expenditures of $20-25 million annually are expected to continue to be funded roughly by cash flow from operations.

UNS Gas has two $50 million issues of senior unsecured notes outstanding, one maturing in 2011 and one maturing in 2015. UNS Gas' short term liquidity needs are supported by a joint UNS Gas/UNS Electric $60 million credit facility which matures August 2011. Either borrower may borrow up to a maximum of $45 million, so long as the combined amount does not exceed $60 million. As of June 30, 2008, no amounts were drawn under the shared credit facility.

The UNS Gas/UNS Electric credit facility contains two financial covenants applicable to each borrower: for UNS Electric a maximum debt to capital ratio of 65% and a minimum interest coverage ratio of 2.25x; for UNS Gas a maximum debt to capital ratio of 67%, and a minimum interest coverage of 2.25x. As of June 30, 2008, the ratios were 53% and 4.24x at UNS Electric and 50% and 3.91x at UNS Gas.

Moody's assumes that UNS Gas will manage the amount of its near term obligations within the limits of its available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook for UNS Gas reflects our expectations of continued stable or modestly improved cash flows resulting from rate case decisions, an assumption that any increases in the cost of gas will continue to be recovered on a relatively timely basis, and our understanding that future capital expenditures will be financed in a manner intended to maintain UNS Gas' current level of financial strength and flexibility.

What Could Change the Rating - Up

UNS Gas' rating is currently constrained by its interdependence with UNS Electric and our view of the consolidated credit quality of UES. In the event this interdependence was reduced while UNS Gas retained its similar credit profile, the rating or outlook could be revised upward. Alternatively, if there were to be an improvement in the consolidated credit quality of UES, this could result in positive rating action for UNS Gas.

What Could Change the Rating - Down

A downward revision could occur if there is deterioration in the credit quality or ratings of UNS Gas or the consolidated credit profile of UES or UNS Electric. If UNS Gas credit metrics decline to the low Baa/high Ba range, for example, RCF/Debt below 10% or EBIT / Interest coverage of less than 2x, or if regulatory support significantly worsens, then there could be a downward revision in the rating or outlook.

Rating Factors

UNS Gas, Inc.

Local Gas Distribution	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Sustainable Profitability (20%)							
a) Return on Equity (15%)				X			
b) EBIT to Customer Base (5%)				X			
Factor 2: Regulatory Support (10%)							
a) Regulatory Support and Relationship					X		
Factor 3: Ring Fencing (10%)							
a) Ring Fencing				X			
Factor 4: Financial Strength and Flexibility (60%)							
a) EBIT/Interest (15%)				X			
b) Retained Cash Flow/Debt (15%)				X			
c) Debt to Book Capitalization (excluding goodwill) (15%)				X			
d) Free Cash Flow/Funds from Operations (15%)			X				
Rating:							
a) Methodology Model Implied Senior Unsecured Rating				**Baa2**			
b) Actual Senior Unsecured Equivalent Rating				**Baa3**			

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EXHIBIT

KCG-2

Exhibit KCG-2

UNS Gas, Inc.
Comparable Company Data

	Gas Distribution Customers	Common Equity as % of Total Capital	Issuer Credit Rating			Market Capitalization ($ Millions)
			S&P	Moody's	Fitch	
AGL Resources Inc.	2,291,000	44.0%	A-	Baa1	A-	$ 2,504
Atmos Energy Corp.	3,205,456	48.5%	BBB	Baa3	BBB	$ 2,379
Laclede Group, Inc.	631,414	56.7%	A	Baa2	A-	$ 947
New Jersey Resources Corporation	467,448	51.2%	A	Aa3	-	$ 1,424
Nicor Inc.	1,912,000	65.6%	AA	A2	A	$ 1,901
Northwest Natural Gas Company	656,784	51.6%	AA-	A3	-	$ 1,191
Piedmont Natural Gas Company, Inc.	963,266	51.3%	A	A3	-	$ 2,007
South Jersey Industries, Inc.	336,410	51.8%	BBB+	Baa2	-	$ 1,021
Southwest Gas Corporation	1,819,000	44.1%	BBB-	Baa3	BBB	$ 1,226
WGL Holdings, Inc.	1,054,958	59.8%	AA-	A2	A+	$ 1,603
Median Value	1,009,112	51.5%	A	A3 / Baa1	A-	$ 1,514

Note:

Where parent company ratings are unavailable, the ratings shown above are those assigned to the largest gas utility subsidiary.

Market Capitalization as of August 2008. Equity ratios as of June 30, 2008.

Sources: SNL Financial for all but Market Capitalization data. Market Capitalization data is from Zacks Investment Research, Value Line, and Yahoo! Finance.

EXHIBIT

KCG-3

Exhibit KCG-3

UNS Gas, Inc.
Projected Growth Rates for Earnings and Dividends
Comparable Company Group

	Value Line Dividend Growth (3 to 5 Years)	Projected Earnings Growth			5-Year Growth Rate for DCF
		Value Line (3 to 5 Years)	Zacks Investment Research (5-Year)	SNL Financial (5-Year)	
AGL Resources	2.3%	3.9%	4.8%	5.3%	4.1%
Atmos Energy Corp.	1.9%	5.2%	5.3%	5.0%	4.3%
Laclede Group, Inc.	2.6%	1.8%	10.0%	NA	4.8%
New Jersey Resources Corporation	5.2%	6.4%	8.0%	6.0%	6.4%
Nicor Inc.	0.0%	10.9%	5.8%	4.5%	5.3%
Northwest Natural Gas Company	5.5%	6.0%	6.5%	5.0%	5.7%
Piedmont Natural Gas Company	3.7%	4.5%	5.4%	6.0%	4.9%
South Jersey Industries, Inc.	3.9%	7.5%	8.3%	7.0%	6.7%
Southwest Gas Corporation	4.2%	6.8%	8.0%	6.0%	6.2%
WGL Holdings, Inc.	2.7%	1.5%	7.5%	4.0%	3.9%
Median Value for Group	3.2%	5.6%	7.0%	5.3%	5.1%

Sources: Value Line, Zacks Investment Research, SNL Financial

EXHIBIT

KCG-4

Exhibit KCG-4

UNS Gas, Inc.
Calculation of Expected First-Year Dividend
Comparable Company Group

	Current Quarterly Dividend	Last Change in Dividend Payment	Recent Ex-Dividend Date	5-Year Growth Rate for DCF	Expected Quarterly Dividends (as of 8/31/08)					Expected First-Year Dividend
					3Q 2008	4Q 2008	1Q 2009	2Q 2009	3Q 2009	
AGL Resources	$0.420	1Q 2008	08/13/08	4.1%		$0.420	$0.437	$0.437	$0.437	$1.731
Atmos Energy Corp.	$0.325	4Q 2007	08/21/08	4.3%		$0.339	$0.339	$0.339	$0.339	$1.356
Laclede Group, Inc.	$0.375	4Q 2007	06/09/08	4.8%	$0.375	$0.393	$0.393	$0.393		$1.554
New Jersey Resources Corporation	$0.280	1Q 2008	06/11/08	6.4%	$0.280	$0.280	$0.298	$0.298		$1.156
Nicor Inc.	$0.465	None Recent	06/26/08	5.3%	$0.465	$0.465	$0.465	$0.465		$1.860
Northwest Natural Gas Company	$0.375	4Q 2007	07/29/08	5.7%		$0.397	$0.397	$0.397	$0.397	$1.586
Piedmont Natural Gas Company	$0.260	1Q 2008	06/23/08	4.9%	$0.260	$0.260	$0.273	$0.273		$1.065
South Jersey Industries, Inc.	$0.270	4Q 2007	06/06/08	6.7%	$0.270	$0.288	$0.288	$0.288		$1.134
Southwest Gas Corporation	$0.225	2Q 2008	08/13/08	6.2%		$0.225	$0.225	$0.239	$0.239	$0.928
WGL Holdings, Inc.	$0.355	2Q 2008	07/08/08	3.9%		$0.355	$0.355	$0.369	$0.369	$1.448

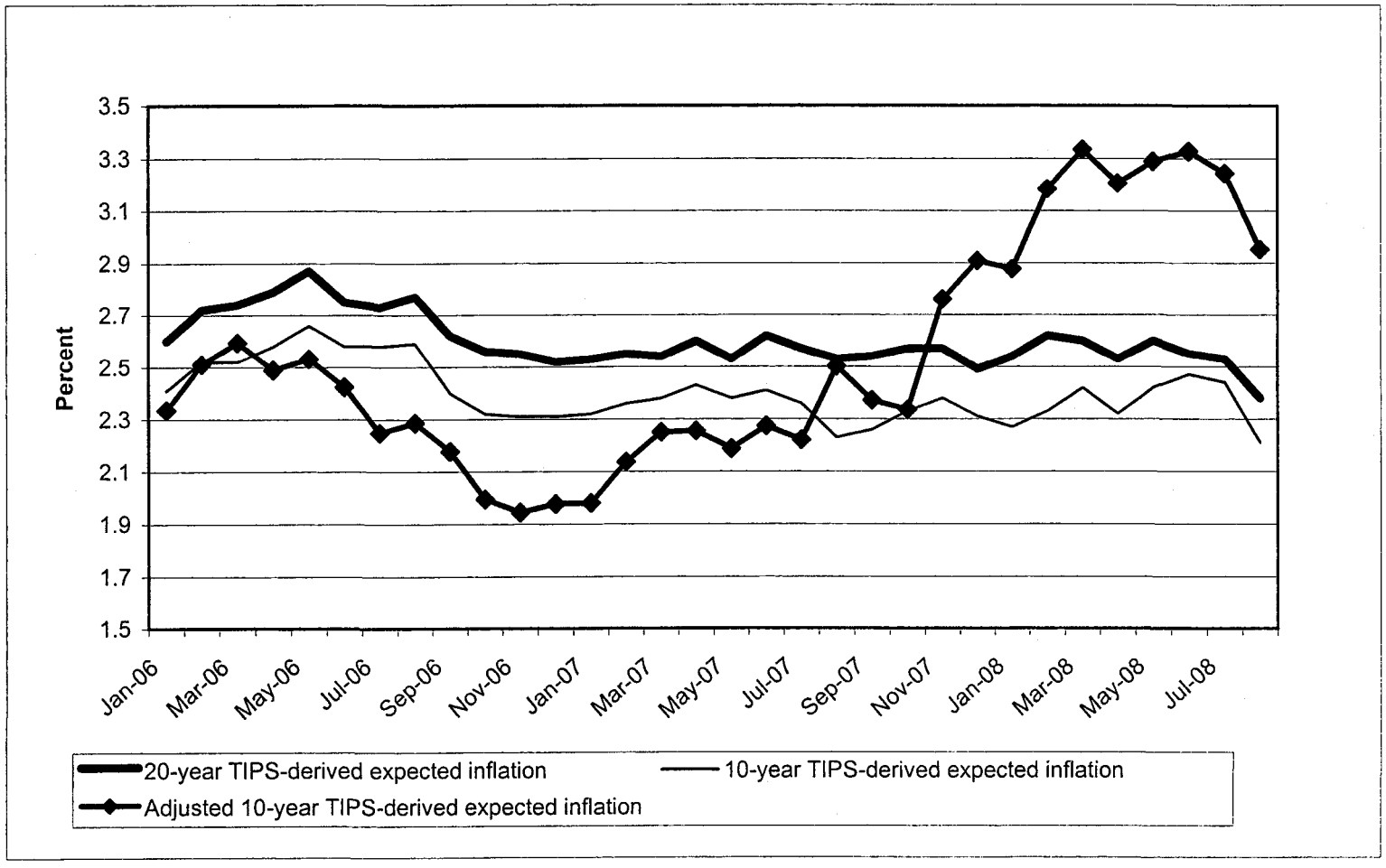
Source: Dividend information is from Yahoo! Finance

EXHIBIT

KCG-5

Exhibit KCG-5

UNS Gas, Inc.
Implied Rate of Inflation from U.S. Treasury Securities



Source: Federal Reserve Bank of Cleveland

EXHIBIT

KCG-6

Exhibit KCG-6

UNS Gas, Inc.
Multi-Stage DCF Analysis
Comparable Company Group

	Recent Avg. Share Price	Projected Dividends Year 1	Year 2	Year 3	Year 4	Year 5	Long-Term Growth	Estimated Cost of Equity
AGL Resources	$ 32.85	$1.73	$1.80	$1.87	$1.95	$2.03	6.3%	11.2%
Atmos Energy Corp.	$ 26.75	$1.36	$1.42	$1.48	$1.54	$1.61	6.3%	11.0%
Laclede Group, Inc.	$ 44.93	$1.55	$1.63	$1.71	$1.79	$1.88	6.3%	9.6%
New Jersey Resources Corporation	$ 34.96	$1.16	$1.23	$1.31	$1.39	$1.48	6.3%	9.6%
Nicor Inc.	$ 43.60	$1.86	$1.96	$2.06	$2.17	$2.29	6.3%	10.4%
Northwest Natural Gas Company	$ 46.95	$1.59	$1.68	$1.77	$1.88	$1.98	6.3%	9.6%
Piedmont Natural Gas Company	$ 28.07	$1.07	$1.12	$1.17	$1.23	$1.29	6.3%	9.9%
South Jersey Industries, Inc.	$ 34.91	$1.13	$1.21	$1.29	$1.38	$1.47	6.3%	9.6%
Southwest Gas Corporation	$ 29.26	$0.93	$0.99	$1.05	$1.11	$1.18	6.3%	9.5%
WGL Holdings, Inc.	$ 32.74	$1.45	$1.51	$1.56	$1.63	$1.69	6.3%	10.4%
Average Value for Group								10.1%

Source: Share prices are from Yahoo! Finance

EXHIBIT

KCG-7

Exhibit KCG-7

UNS Gas, Inc.
Application of Capital Asset Pricing Model
Comparable Company Group

	Risk-Free Rate		Beta		Equity Risk Premium		Estimated Cost of Equity
AGL Resources Inc.	4.53%	+	0.85	x	7.10%	=	10.6%
Atmos Energy Corp.	4.53%	+	0.85	x	7.10%	=	10.6%
Laclede Group, Inc.	4.53%	+	0.90	x	7.10%	=	10.9%
New Jersey Resources Corporation	4.53%	+	0.85	x	7.10%	=	10.6%
Nicor Inc.	4.53%	+	0.95	x	7.10%	=	11.3%
Northwest Natural Gas Company	4.53%	+	0.80	x	7.10%	=	10.2%
Piedmont Natural Gas Company	4.53%	+	0.85	x	7.10%	=	10.6%
South Jersey Industries, Inc.	4.53%	+	0.85	x	7.10%	=	10.6%
Southwest Gas Corporation	4.53%	+	0.90	x	7.10%	=	10.9%
WGL Holdings, Inc.	4.53%	+	0.90	x	7.10%	=	10.9%
Average Value for Group							10.7%

Notes

Risk-free rate is 20-Year Treasury Constant Maturity Rate (Average for August 2008).

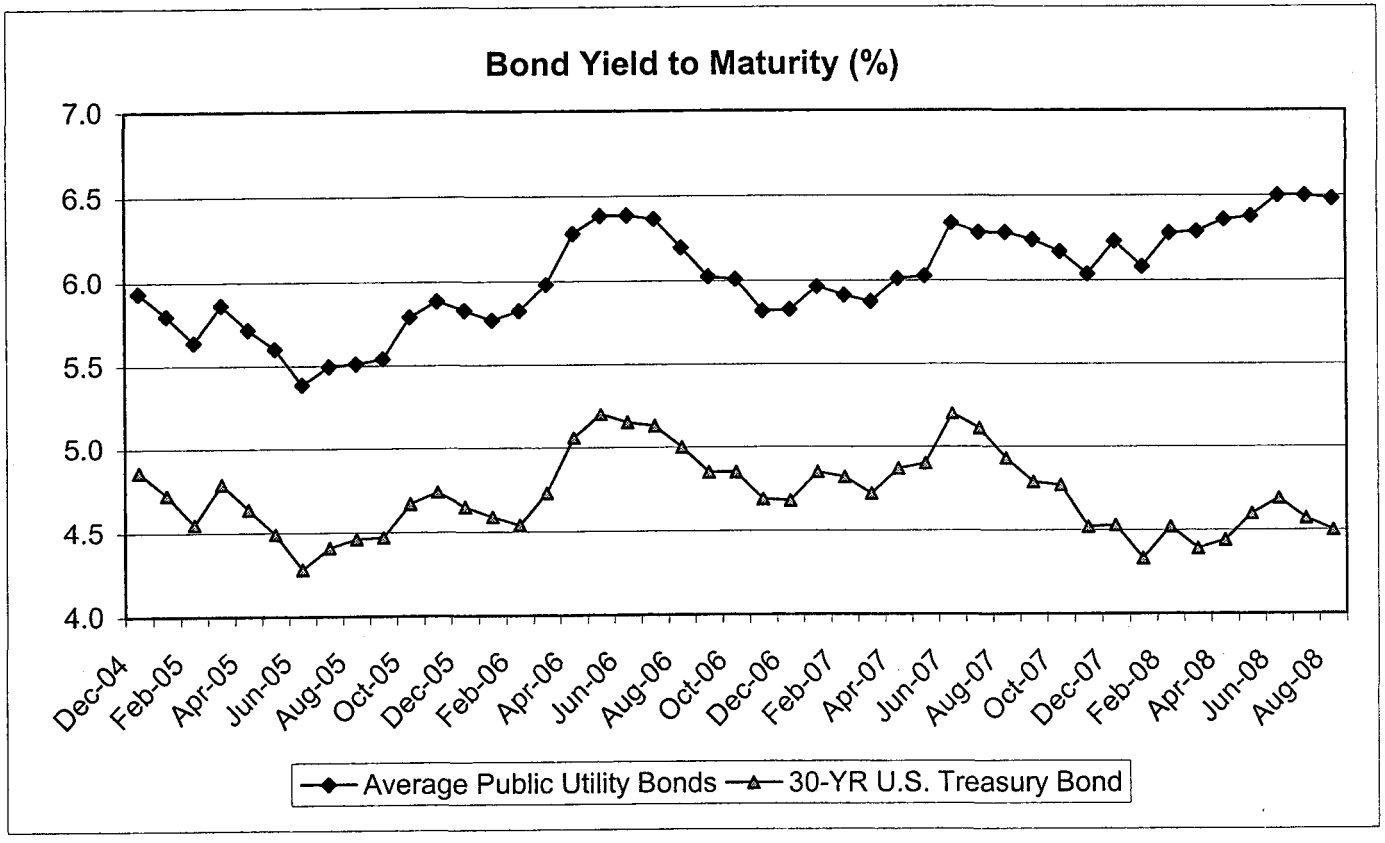
Sources: 20-Year U.S. Treasury Constant Maturity Rate is from the Federal Reserve Board of Governors Web site (www.federalreserve.gov). Beta values are from Value Line. Equity Risk Premium is from Morningstar SBBI 2008 Yearbook.

EXHIBIT

KCG-8

Exhibit KCG-8

UNS Gas, Inc.
Yields on Public Utility Bonds and U.S. Treasury Bonds



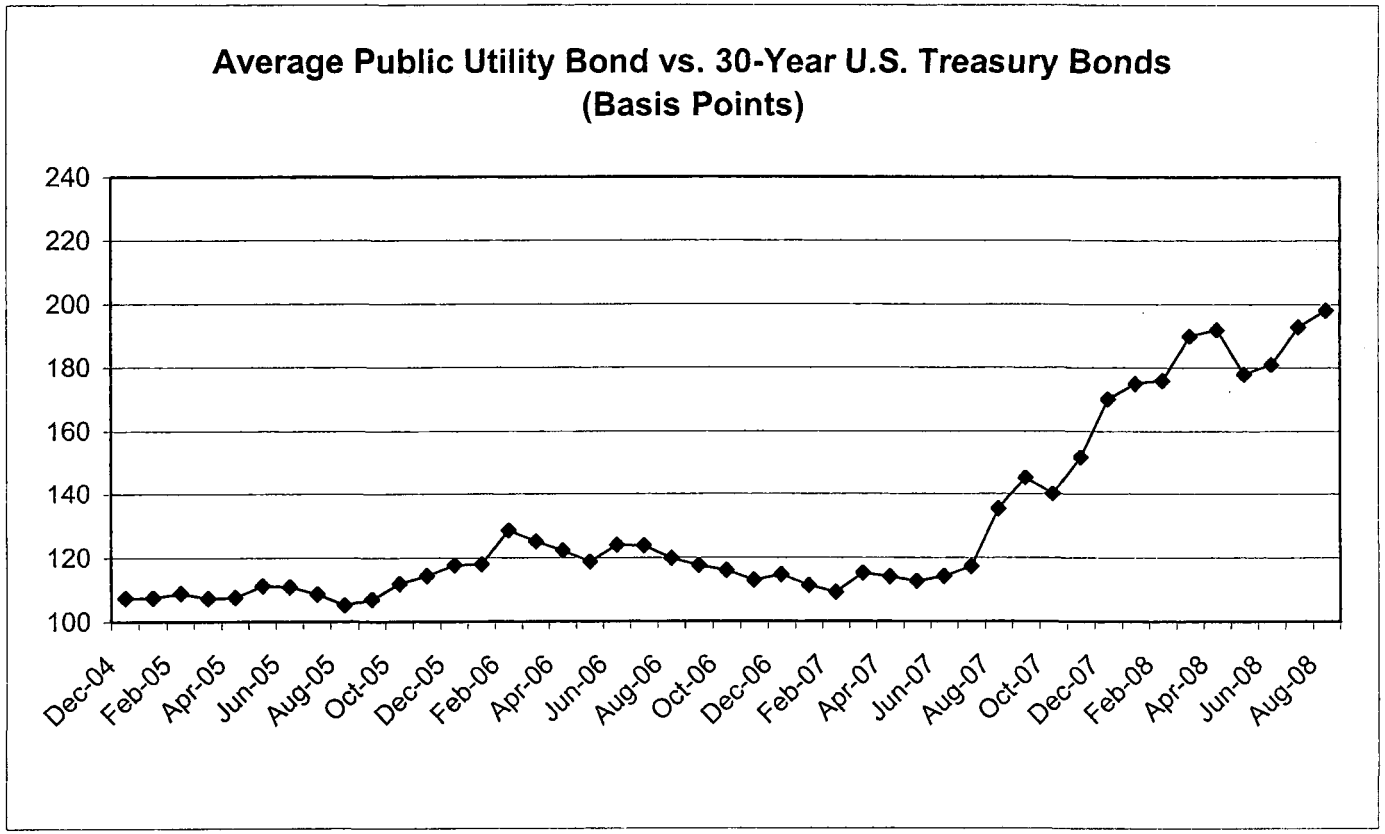
Sources: Public Utility bond yields are from Mergent Bond Record. 30-Yr. U.S. Treasury bond yields are from Mergent Bond Record (Dec 2004 - Jan 2006 data) and the Federal Reserve Board of Governors Web site (www.federalreserve.gov, Feb 2006 - August 2008 data).

EXHIBIT

KCG-9

Exhibit KCG-9

UNS Gas, Inc.
Public Utility Bond Credit Spreads



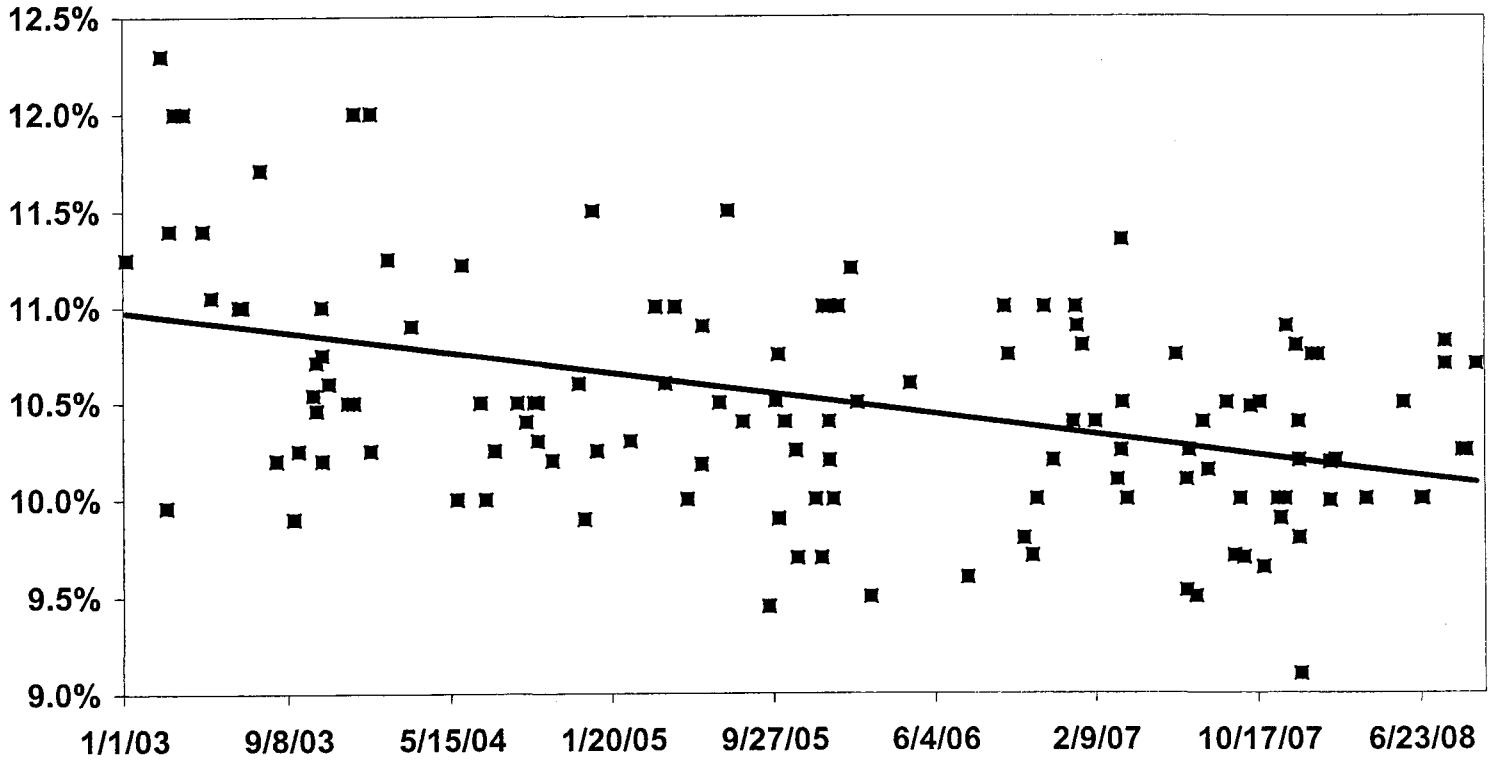
Sources: Public Utility bond yields are from Mergent Bond Record. 30-Yr. U.S. Treasury bond yields are from Mergent Bond Record (Dec 2004 - Jan 2006 data) and the Federal Reserve Board of Governors Web site (www.federalreserve.gov, Feb 2006 - August 2008 data).

EXHIBIT

KCG-10

Exhibit KCG - 10

UNS Gas, Inc.
Allowed ROEs for Gas Distribution Companies



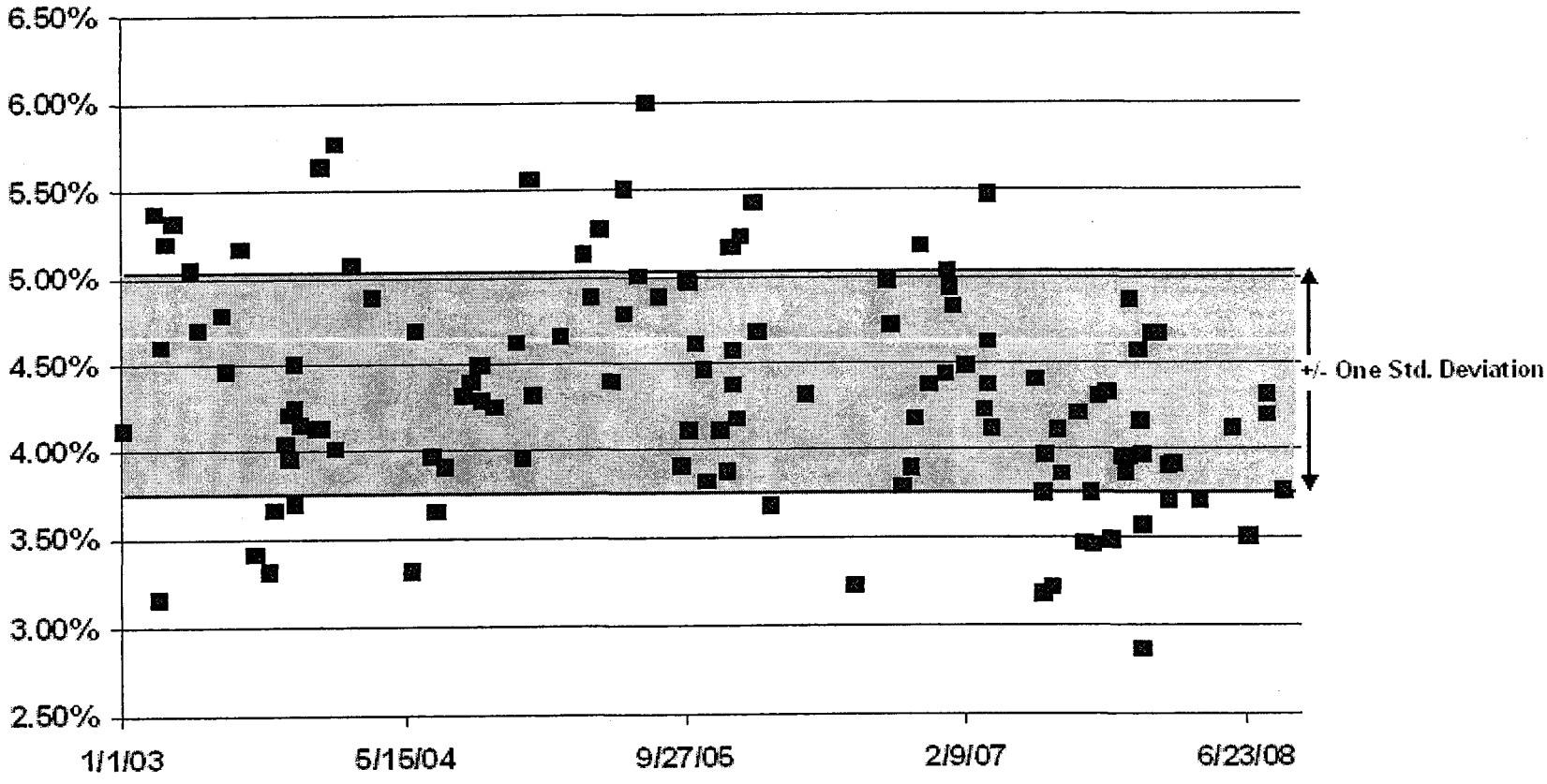
Note: Trend line shown derived from least-squares linear regression.
Source: SNL Financial.

EXHIBIT

KCG-11

Exhibit KCG - 11

UNS Gas, Inc.
Allowed ROE Risk Premium over Avg. Public Utility Bond Yield



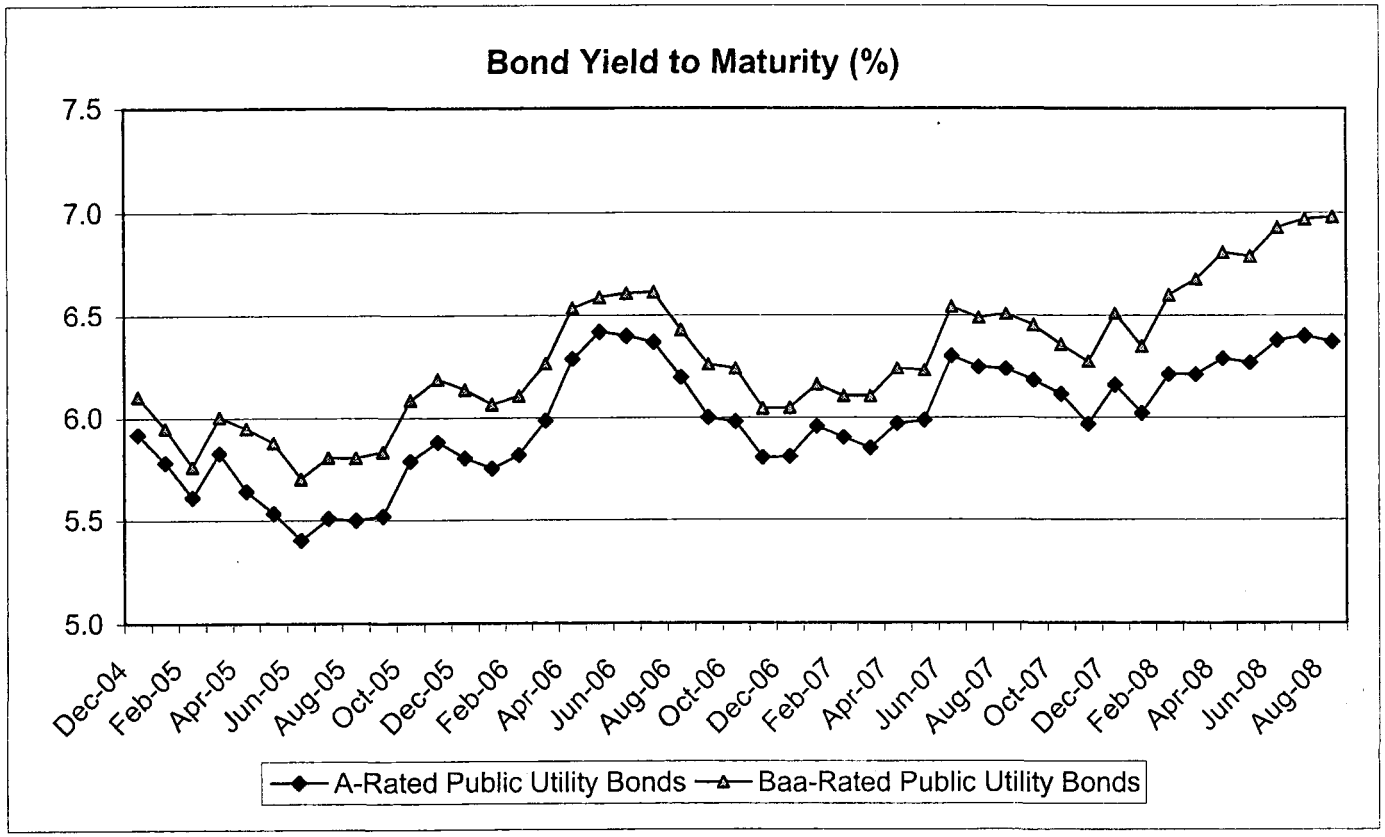
Sources: Allowed ROE data is from SNL Financial. Public Utility bond yields are from Mergent Bond Record.

EXHIBIT

KCG-12

Exhibit KCG-12

UNS Gas, Inc.
Public Utility Bond Yields for A-Rated and Baa-Rated Utilities



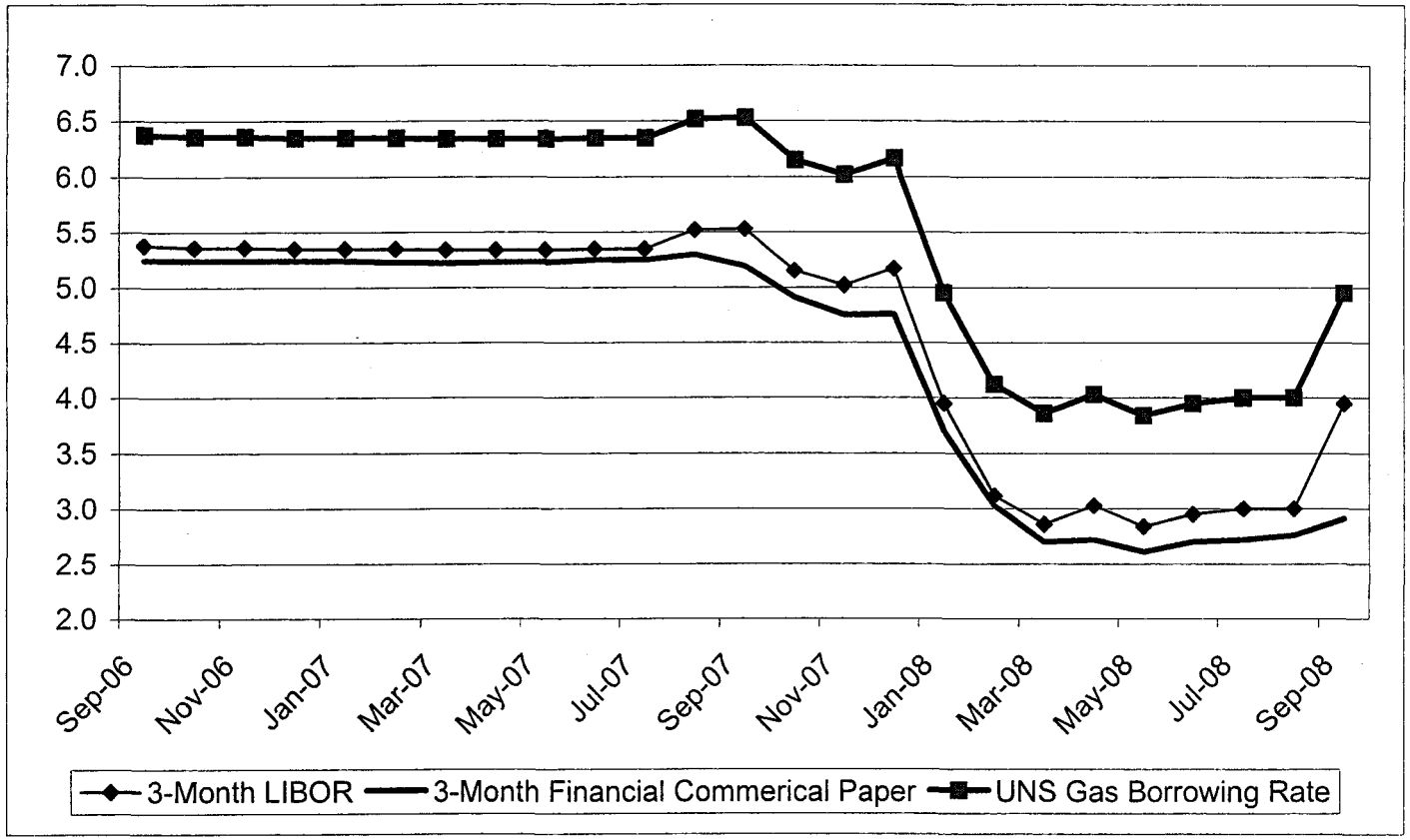
Source: Public Utility bond yields are from Mergent Bond Record

EXHIBIT

KCG-13

Exhibit KCG-13

UNS Gas, Inc.
Short-Term Interest Rates (%)



Source: LIBOR and Financial Commercial Paper yields are from the Federal Reserve Board of Governors Web site (www.federalreserve.gov).

EXHIBIT
UNSG-14
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

July 8, 2009

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Exhibit KCG-14 Public Utility Bond Credit Spreads
Exhibit KCG-15 Public Utility Bond Yields for A-Rated and Baa-Rated Utilities
Exhibit KCG-16 Rates for 3-Month LIBOR and Financial Commercial Paper

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc ("UNS Gas" or the "Company").

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

A. The purpose of my Rebuttal Testimony is to rebut portions of the direct testimony of Mr. David C. Parcell and Mr. Robert G. Gray filed by the Arizona Corporation Commission Staff ("Staff"), as well as portions of the direct testimony of Mr. William A. Rigsby and Mr. Ralph C. Smith filed by the Residential Utility Consumers Office ("RUCO"). The subject matter addressed in my Rebuttal Testimony includes: (i) the cost of equity capital to UNS Gas, (ii) the ability of UNS Gas to earn its cost of equity capital, (iii) the determination of a fair rate of return ("ROR") on fair value rate base ("FVRB") and (iv) the appropriate rate of interest to apply to under- and over-recoveries of gas costs under the Company's purchased gas adjustor ("PGA") rate mechanism.

Q. Please summarize the essential points presented in your Rebuttal Testimony.

A. Certainly. With respect to the cost of equity capital, the 10.0% cost recommended by Mr. Parcell and the 8.61% cost recommended by Mr. Rigsby both fall well short of the actual cost of equity to UNS Gas. In making these recommendations, both witnesses have failed

to properly take into account the substantial deterioration in capital market conditions and increase to the cost of capital that has occurred since September of 2008. As both witnesses acknowledge, the ability of a public utility to attract capital on reasonable terms is an important policy objective when setting rates. However, by recommending an authorized return on equity ("ROE") that is well below the Company's actual cost of equity, the end result of these recommendations would be to deny UNS Gas the ability to attract capital on reasonable terms.

Regarding the Company's ability to actually earn its cost of equity capital, neither Mr. Parcell nor Mr. Rigsby presented any analysis on this point even though both witnesses acknowledge the importance of the *Hope* and *Bluefield* decisions rendered by the United States Supreme Court. Despite this lack of analysis, both witnesses make summary statements suggesting that UNS Gas will be able to attract capital on reasonable terms if the rate recommendations of Staff and RUCO are adopted by the Commission. Such suggestions are clearly off the mark in this case.

Assuming Staff's recommended rate increase is adopted, UNS Gas estimates that it will be able to earn a ROE of only 6% to 7% in the first full year under new rates. Assuming RUCO's recommended rate increase is adopted, the Company estimates it would be able to earn a ROE of only 5% to 6%. These returns on equity capital are substantially below the 11.0% cost of equity presented in my Direct Testimony, and are also well below the unreasonably low cost estimates of 10.0% and 8.61% recommended by Mr. Parcell and Mr. Rigsby, respectively. Under these circumstances, it is difficult to see how the overall rate recommendations of Staff and RUCO can be characterized as being just and reasonable, or in the public interest.

With respect to the determination of a fair ROR on FVRB, Mr. Parcell, Mr. Smith and Mr. Rigsby all claim to provide recommendations that are consistent with the ruling in Decision No. 70441 by the Arizona Corporation Commission ("Commission") involving Chaparral City Water Company ("Chaparral"). While my non-legal understanding is that the Commission has some latitude in setting a fair ROR on FVRB, the methodologies proposed by Staff and RUCO in this case are clearly not the same as the methodology used by the Commission in Decision No. 70441, nor are they the same as was subsequently recommended by Staff in Docket No. W-02113A-07-0551. The returns on FVRB recommended by Mr. Parcell and Mr. Smith are well below the values that would be obtained using the approach adopted in Decision No. 70441. Although Mr. Parcell and Mr. Smith offer lengthy explanations supporting their ultimate recommendations, neither witness offered any substantive analysis showing why, in the case of UNS Gas, a different approach should be used. This lack of substantive analysis, including the impact of their recommendations on UNS Gas' financial situation, is why the Commission should find that Mr. Parcell's and Mr. Smith's recommendations on a ROR on FVRB is too low in light of the need for UNS Gas to maintain its financial integrity and have access to capital on reasonable terms.

Finally, with respect to the appropriate interest rate to be applied to under- and over-recoveries of gas costs under the PGA, I agree with Mr. Gray that it would be preferable to use a benchmark rate for which monthly averages are readily available. However, the simple fact of the matter is that UNS Gas cannot borrow at the interest rate currently used for the bank balance -- the three-month financial commercial paper rate published by the Federal Reserve. Under cost of service ratemaking principles, UNS Gas should be provided with an opportunity to recover its actual cost of borrowing when it is required to carry an under-recovered balance of purchased gas costs. This rate is currently equal to the London Interbank Offered Rate ("LIBOR") plus 1.0%. In my Rebuttal Testimony I offer a

straightforward process for identifying the monthly average rate for three-month LIBOR rate, and provide an alternative recommendation that would simply add 1.0% to the financial commercial paper rate currently used to accrue carrying costs on the PGA balance.

II. COST OF COMMON EQUITY CAPITAL.

A. Rebuttal of Staff Witness David C. Parcell.

Q. Mr. Grant, please summarize your view of the cost of capital testimony filed by Staff Witness David Parcell.

A. Certainly. While Mr. Parcell has agreed with the Company's proposed capital structure and cost of debt, he has recommended a cost of equity of 10.0% for UNS Gas. This value is a full 1.0% below the cost proposed by UNS Gas and is well below the Company's cost of equity in the current economic environment. All three of his analyses, which rely on a Capital Asset Pricing Model (CAPM), a Discounted Cash Flow (DCF) model and a Comparable Earnings (CE) approach, contain significant flaws that serve to significantly understate the cost of equity capital to UNS Gas.

Q. What comments do you have with respect to Mr. Parcell's use of the CAPM?

A. While Mr. Parcell did not give much weight to his CAPM analysis in formulating his recommendation, his use of the CAPM is flawed since his market risk premium does not adequately reflect the cost of risk currently priced into debt and equity securities in the capital markets.

Q. Please elaborate on Mr. Parcell's calculation of the market risk premium.

A. Similar to the approach I took in my Direct Testimony, Mr. Parcell used historical returns on common stocks and U.S. Treasury Bonds to derive a long-term historical risk premium. This historical risk premium was then used as a proxy for the expected market risk premium currently required by investors to invest in a market portfolio of common stocks. During periods of relative calm in the capital markets, this approach to estimating the expected market risk premium is a reasonable approach. However, during periods of significant turbulence in the capital markets, when the willingness of investors to take on risk is seriously reduced, the use of an historical market risk premium as a proxy for the current expected risk premium is not appropriate.

Q. Please explain why the historical market risk premium is not applicable in today's capital markets.

A. Recent events in the capital markets should make this point readily apparent. As acknowledged by Mr. Parcell, the capital markets have been impacted by a financial crisis of extreme proportions. On page 14 of his Direct Testimony, lines 16-21, Mr. Parcell provides the following commentary on recent events:

> It is apparent that recent and current economic/financial circumstances are radically different from any that have prevailed since at least the 1930s. The recent deterioration in stock prices and the decline in U.S. Treasury bond yields and increase in corporate bond yields reflect the "flight to safety" that describes the extreme reluctance of investors to purchase common stocks and corporate bonds while moving investments into the very safe government bonds.

Based on this description, and the abundance of market evidence supporting it, it is readily apparent that investors have become much more risk averse as a result of the ongoing financial crisis. Since the failure of Lehman Brothers in September 2008, the returns demanded by investors on U.S. Treasury securities have plummeted while the returns required on investments in corporate bonds and stocks have increased significantly.

Because U.S. Treasury securities are perceived as having lower risk than corporate bonds and stocks, this increased spread between Treasury securities and corporate securities shows that investors are demanding a higher risk premium from corporate securities than in the past. In short, the cost of bearing risk has increased significantly. Consequently, the historic market risk premium does not reflect the current risk premium demanded by investors. This increased aversion to risk has affected the both the cost and availability of capital to corporations, including those in the gas utility industry.

Q. What specific evidence can you cite regarding the recent increase to the cost of capital for utilities?

A. Exhibit KCG-14 attached to this Rebuttal Testimony shows the additional return demanded by investors for an investment in public utility bonds relative to U.S. Treasury bonds. The Exhibit delineates that the average spread between the returns required on public utility bonds and U.S. Treasury bonds remained fairly stable until August of 2007, when it began rising in response to broader market concerns over mortgage-backed securities and the health of certain financial institutions. However, in September of 2008 this credit spread spiked significantly higher, indicating a strong shift away from corporate securities and into U.S. Treasury securities.

Further evidence regarding the recent increase in capital costs can be seen in Exhibit KCG-15, which shows recent required returns on both A-rated and Baa-rated public utility bonds where required interest rates on these securities also spiked in September of 2008. Since that time, required returns on A-rated public utility bonds have returned to levels that are comparable to pre-crisis conditions. However, reflecting the decrease in investor risk tolerance, the required returns on lower quality Baa-rated public utility bonds, have remained much higher than those observed during the pre-crisis era. UNS Gas is currently rated at Baa3 by Moody's, which is the lowest investment grade rating assigned by

Moody's. [1] It should therefore be readily apparent, based on the absolute level of bond yields, as well as the credit spread between higher quality and lower quality debt securities, that the cost of capital for utilities has increased, particularly for lower-rated utilities like UNS Gas.

Q. Are you saying that the cost of equity capital has increased for public utilities as a result of recent market developments?

A. Yes. An investment in the common stock of a utility is inherently more risky than an investment in the utility's bonds. As evidenced by the widening of credit spreads between public utility bonds and U.S. Treasury bonds, and between A-rated public utility bonds and lower quality Baa-rated public utility bonds, it is apparent that investors in public utility securities are demanding much higher returns for every increment of risk to which they are exposed. Additionally, this increase in investor risk aversion is at least partially responsible, if not entirely, for the large sell-off in public utility common stocks that has taken place since mid-2008. In light of this empirical market evidence, it is reasonable to conclude that the cost of equity capital for public utilities has also increased significantly.

Q. You mentioned the large sell-off in public utility common stocks. Can you provide more information on this recent event and its implications for the cost of equity for utilities?

A. Although utility stocks have fared better than most common stocks, the shares of most publicly-traded utilities have been hit hard since September of 2008. A simple comparison of the average stock price for the gas utility proxy group referenced in Mr. Parcell's Direct Testimony and my own Direct Testimony is very revealing. The stock prices for these ten companies are listed on Exhibit KCG-6 attached to my Direct Testimony and on Schedule 7, page 1, of Mr. Parcell's Direct Testimony. A simple average of the stock prices

[1] Moody's is the only rating agency that issues a credit rating for UNS Gas.

appearing in my Exhibit KCG-6, which is based on pricing data for the month of August 2008, is $35.50. By contrast, the simple average of the stock prices appearing in Mr. Parcell's schedule, which is based on pricing data from February through April 2009, is $31.63. This decline of 11% over a six month time period is quite substantial for an industry that is viewed as being relatively stable when compared with other industries. Although a portion of this stock price decline may be attributable to lower expectations for near-term earnings growth, a much larger factor is the "flight to safety" referenced by Mr. Parcell in his Direct Testimony. Because of this flight to safety and the increased reluctance of investors to expose themselves to risk, the availability of equity capital has decreased while the cost of this capital has increased for utilities and other corporations in general.

Q. Please summarize your concerns with Mr. Parcell's use of the CAPM.

A. In short, while Mr. Parcell used a risk-free rate that reflects the recent "flight to safety" in the capital markets, he failed to adjust his historical market risk premium to also reflect this flight to safety. By failing to adjust his market risk premium to reflect the substantial increase in the cost of bearing risk, he significantly underestimated the cost of equity for the companies included in his proxy groups. The range of 7.3% to 7.7% obtained from his CAPM analysis is so low that it does not even cover the cost of borrowing for most of the utilities used in his proxy groups. As may be seen on page 4 of Schedule 2 attached to Mr. Parcell's Direct Testimony, the required return on Baa-rated public utility bonds has ranged from a low of 7.74% to a high of 8.98% over the period October 2008 through April 2009. In order for Mr. Parcell's CAPM analysis to have any credibility at all, one would have to believe that investors would be willing to accept a negative risk premium to invest in the common stock of a Baa-rated public utility. Such a phenomenon is hard to imagine even during normal times, let alone during times of heightened investor risk aversion.

Q. Mr. Grant, does your CAPM analysis suffer from this same flaw?

A. No, it does not. Because my analysis relied on market data from August 2008, a period of relative stability that preceded the massive flight to quality and increase in required risk premiums, no additional adjustment to my historical-based market risk premium was required.

Q. In his Direct Testimony, Mr. Parcell was critical of your use of arithmetic mean returns in calculating an historical market risk premium. Are his concerns valid?

A. No. Because an arithmetic mean return reflects the mathematical average of historical returns realized over each discrete 12 month period, the use of a risk premium based on arithmetic mean returns is more appropriate when calculating a discount rate (*i.e.*, the cost of capital) that is used for discounting future annual cash flows (*i.e.*, dividends and capital gains). By contrast, the geometric mean return, which equals the compound average return earned over a multi-year period, is appropriate for reporting and comparing returns over historical time periods. Since the geometric mean is always less than the arithmetic mean for any series of data having non-constant annual rates of return, Mr. Parcell's application of the CAPM serves to inappropriately understate the cost of equity capital for the companies he examined.

The use of arithmetic mean returns versus geometric mean returns is specifically addressed by Morningstar, Inc., the publisher of historical financial return data cited in the direct testimony of Mr. Parcell as well as in my own direct testimony. On page 59 of the 2009 Yearbook (Valuation Edition) published by Morningstar, the following commentary is provided:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the

> building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

Q. Mr. Parcell also criticized your use of bond income returns instead of bond returns that also incorporate capital gains and losses. What is your response to that concern?

A. It is a widely accepted practice to use bond income returns instead of bond returns that incorporate capital gains and losses. As explained on page 58 of the 2009 Yearbook (Valuation Edition) published by Morningstar, it is more appropriate to use income returns on bonds when estimating the market risk premium:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation...Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Q. In addition to criticizing your application of the CAPM, Mr. Parcell also found fault with the Bond Yield plus Risk Premium approach described in your Direct Testimony. Do you have any response to his critique?

A. Yes. On page 43 of his Direct Testimony, lines 16-17, Mr. Parcell states his belief that the "upper portion" of my equity risk premium range is not appropriate. He arrives at this conclusion, at least in part, by focusing his review on data from a shorter and more recent time period. However, as pointed out on page 22 of my Direct Testimony, the range of implied equity risk premiums has drifted lower since mid-2007 due in large part to rising bond yields and the regulatory lag inherent in the utility rate-setting process. By focusing on a shorter and more recent time period, Mr. Parcell has accentuated the impact of

regulatory lag in a rising interest rate environment. By contrast, my analysis relied on data from a longer time period, and is therefore less affected by the recent run-up in bond yields and the downward bias in equity risk premiums associated with regulatory lag in a rising interest rate environment.

Q. On page 44 of his Direct Testimony, Mr. Parcell suggests that a 4.0% equity risk premium would be more appropriate, resulting in a cost of equity of about 10.5%. Even if you accept his lower risk premium of 4.0%, do you agree that this would result in a cost of equity of 10.5%?

A. No. As may be seen on page 43 of his Direct Testimony, Mr. Parcell based his 4.0% equity risk premium on the spread over yields on Baa-rated public utility bonds, whereas my analysis was based on the spread over the average yield on public utility bonds having ratings from Baa through Aa. Mr. Parcell's 10.5% cost of equity estimate was derived by adding his 4.0% equity risk premium to the 6.48% average yield on public utility bonds cited on page 23 of my Direct Testimony. To be consistent with his derivation of a 4.0% equity risk premium, Mr. Parcell should have added his 4.0% equity risk premium to the 6.98% yield on Baa-rated public utility bonds as of August 2008. Had he done so, he would have concluded that 11.0% is a more appropriate cost of equity estimate. Additionally, had Mr. Parcell added his 4.0% equity risk premium to the 8.03% yield on Baa-rated utility bonds as of April 2009, he would have obtained an even higher estimate of 12.0%. Page 4 of Schedule 2 attached to Mr. Parcell's Direct Testimony contains a summary of recent yields on Baa-rated public utility bonds.

Q. What comments do you have regarding Mr. Parcell's application of the DCF model?

A. Mr. Parcell used the constant growth version of the DCF model, which assumes that the dividends and earnings of a company grow at a constant rate on a per-share basis over an infinite time period. Therefore, the selection of an appropriate growth rate can have a huge

impact on the validity of the results obtained. Unfortunately, based on a review of the growth rates selected by Mr. Parcell, it is apparent that many of the growth rates he used are unrealistically low, especially when adjusted for inflation. As a result, the cost of equity he determined from his DCF analysis, 9.5% to 10.5%, is much too low.

Q. What has the Commission said about the constant growth version of the DCF?

A. The Commission has often rejected use of the constant growth or single stage DCF when used in isolation. The Commission has recognized that investors do not expect a single, uniform growth rate, explaining that use of the multi-stage DCF "properly recognizes that investors expect both non-constant short-term growth as well as constant long term growth."[2] Thus, the Commission often considers both types of DCF, and averages the results of the two to produce an overall DCF estimate. Staff has proposed, and the Commission has approved, that approach to the DCF in many orders.[3]

Q. Please explain your concern over the growth rates selected by Mr. Parcell.

A. The growth rates used by Mr. Parcell in his DCF analysis can be found in the next to last column of data on page 4 of Schedule 7 attached to his Direct Testimony. These "average" growth rates reflect the numerical average of five growth rates, two of which are based on historical financial data and three of which are forward-looking estimates. If you look carefully at the "average" growth rates used by Mr. Parcell, two things stand out. First, the range of values selected is quite wide, especially for the group of gas distribution utilities labeled as the "Grant Comparable Company Group." Since all of these companies operate within the same heavily regulated industry, and face many of the same threats and opportunities as other firms in this industry, it is unrealistic to believe that investors would expect infinite growth rates ranging from a low of 3.3% to a high of 7.3%. While it is

[2] Decision 66849 at 22.

[3] See e.g. No. 68176 at page 21 (stating Staff's approach) and 26 (agreeing with Staff); Decision No. 68858 at 25, 28; Decision No. 69164 at 23, 26; Decision No. 69440 at 18, 20; Decision No. 70209 at 27, 30.

possible to expect such a wide range of growth rates for period of three to five years, the timeframe typically covered by stock market analyst estimates, a spread that wide is simply unrealistic for the infinite time period assumed in Mr. Parcell's DCF model.

Second, as I mentioned earlier, some of the growth rates selected by Mr. Parcell are unrealistically low, especially when adjusted for inflation. In his electric utility proxy group, referred to as the "Parcell Proxy Group" in his Direct Testimony, three companies have "average" growth rates below four percent, ranging from 2.5% to 3.5%. In the proxy group consisting of gas utilities, referred to as the "Grant Comparable Company Group" in his Direct Testimony, three companies also have "average" growth rates below four percent, ranging from 3.3% to 3.9%. If the inflation rate of 2.0% discussed by Mr. Parcell on page 50 his Direct Testimony is subtracted from these nominal dollar growth rates, a real rate of earnings growth ranging from 0.5% to 1.9% is obtained for the six companies just described. It is simply unrealistic to believe that investors would expect such a low rate of earnings growth, particularly when real growth in the U.S. economy has averaged approximately 3.4% per year over long periods of time spanning numerous economic cycles and periods of both war and peace. Had Mr. Parcell used more realistic expected growth rates for these six companies, it is likely he would have obtained a cost of equity that is much closer to the results I obtained using a multi-stage version of the DCF model.

Q. What results might Mr. Parcell have obtained had he used more realistic growth rates for the companies he examined?

A. Had Mr. Parcell simply added an additional 1.5% to the growth rates for the six companies identified above, the average growth rate for the electric utility proxy group would have increased from 3.9% to approximately 4.5%, while the average growth rate for the gas utility proxy group would have increased from 5.0% to approximately 5.5%. When these still conservative growth rates are added to the adjusted average dividend yields listed on

page 4 of Schedule 7 attached to Mr. Parcell's Direct Testimony, the resulting average cost of equity obtained ranges from 10.1% to 11.1% for the utility proxy groups he analyzed.

Q. Mr. Parcell also relied on a Comparable Earnings analysis to arrive at his recommended cost of equity. Has the Commission rejected this approach in the past?

A. Yes. The Commission rejected the comparable earnings approach in Decision No. 68302 (November 14, 2005), noting that it "has long been discredited for several reasons."[4]

Q. What other comments do you have regarding Mr. Parcell's Comparable Earnings approach?

A. My overall reaction is that Mr. Parcell's analysis should be afforded little, if any, weight. This approach is based on the faulty premise that investors use historical accounting returns on book equity in order to determine the required future returns on common stock investments. Additionally, his conclusions were influenced by an analysis of earned returns for electric utilities, an industry whose historical earnings have been significantly impacted by restructuring efforts and other factors that are not relevant to the gas distribution industry. Finally, assuming the Comparable Earnings approach has any merit at all, Mr. Parcell's extensive commentary on historical market-to-book ratios is inaccurate. The downward adjustment that Mr. Parcell makes to the historically observed returns on equity, due to the presence of market-to-book ratios that are apparently too high - in his opinion, is unwarranted and would be punitive to a company like UNS Gas that must compete for common equity in the capital markets.

[4] Decision No. 68302 at 37-38.

Q. What issues do you have with Mr. Parcell's interpretation of historical market-to-book ratios?

A. First, as stated on page 33 of his Direct Testimony (lines 14-16), Mr. Parcell indicates that in reviewing the realized returns on equity, he evaluated "the investor acceptance of these returns by reference to the resulting market-to-book ratios." Unfortunately, this evaluation of market-to-book ratios is based on an erroneous assumption that market-to-book ratios are somehow indicative of "investor acceptance" of realized returns on equity. The simple fact is that market-to-book ratios for publicly-traded companies are impacted by a wide variety of factors other than historical returns on equity. The numerator of this ratio, the market value of a company's common stock, is driven primarily by forward-looking information and shifting investor preferences, and not by historical or contemporaneous realized returns. Likewise, the denominator of this ratio, the book value of a company's shareholder interest, can be influenced by many factors including changes in accounting guidelines, write-offs of investments, the issuance of new common stock, etc.

The second major flaw in his interpretation of market-to-book ratios is revealed on page 37 of his Direct Testimony, lines 11-13, where Mr. Parcell concludes that "a market price of a utility's common stock that is 150% or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital." In order for this conclusion to have any validity at all, one would have to believe that 90% of the companies in the gas utility proxy group referenced by Mr. Parcell were over-earning for the period 1992-2001, and that 80% of these same utilities were over-earning for the period 2002-2008. As may be seen on page 2 of Schedule 10 attached to Mr. Parcell's Direct Testimony, the average market-to-book ratio for the gas utility proxy group was 179% over the period 1991-2001 and 183% over the period 2002-2008.

Q. What conclusions, if any, can be drawn from Mr. Parcell's Comparable Earnings Approach?

A. Assuming this approach has any validity at all, the unadjusted returns on equity for the gas utility proxy group should be considered in lieu of the adjusted range derived by Mr. Parcell. As may be seen on page 35 of his Direct Testimony, the average unadjusted historic ROE for the gas utility proxy group (identified as the "Grant Group" in his testimony) is shown to be 11.8% to 11.9%. This is consistent with the average ROE of 11.5% to 12.2% referenced on page 5 of my Direct Testimony, which was derived from Value Line reports for the gas distribution industry for the period 2005-2007. Since UNS Gas must compete for capital with gas utilities earning 11.5% to 12.2%, Mr. Parcell's adjusted range of 9.5% to 10.5% would put UNS Gas at a competitive disadvantage in attracting new equity capital and would not provide the Company with an opportunity to earn a reasonable rate of return. Therefore, it must be rejected as a basis for setting the cost of equity in this proceeding.

Q. Based on your review of Mr. Parcell's Direct Testimony, what conclusions can be drawn regarding the cost of equity for UNS Gas?

A. When corrected for the flaws described above, I believe that Mr. Parcell's analysis fully supports the cost of equity of 11.0% proposed by UNS Gas. Assuming his CAPM analysis is afforded little or no weight, which appears to be consistent with Mr. Parcell's reasoning, any conclusions to be drawn from his testimony would be limited to the results obtained from his constant-growth DCF model, his Comparable Earnings approach and his commentary on the Bond Yield plus Risk Premium approach. The table below summarizes the conclusions reached by Mr. Parcell from each of these approaches, as well as the results I obtained by making relatively simple corrections to his analyses as described above:

	Parcell Testimony	As Corrected
Constant-Growth DCF	9.5-10.5%	10.1-11.1%
Comparable Earnings	9.5-10.5%	11.8-11.9%
Bond Yield + Risk Premium	10.5%	11.0-12.0%

Finally, I would note that the results summarized above reflect the cost of equity capital to a proxy group of gas distribution utilities, and are not specific to UNS Gas. As discussed on pages 24-25 of my Direct Testimony, an equity investment in UNS Gas is decidedly riskier than an investment in the proxy group of gas utility companies. As such, it is reasonable to conclude that the cost of equity for UNS Gas is near the high end of the range established for the proxy group of companies.

B. <u>Rebuttal of RUCO Witness William A. Rigsby.</u>

Q. Mr. Grant, please summarize your view of the cost of capital testimony filed by RUCO Witness William Rigsby.

A. Certainly. While Mr. Rigsby has agreed with the Company's proposed capital structure and cost of debt, he has recommended a cost of equity of only 8.61% for UNS Gas. This value is a full 2.39% below the 11.0% cost proposed by UNS Gas, and is well below the cost of equity determined for any U.S. investor-owned gas utility since at least 1990 and probably much longer. Although the results he obtained from his application of a constant-growth DCF model fully support the Company's request, Mr. Rigsby decided to average the results of his DCF and CAPM analyses in arriving at his recommended value of 8.61%. As I discuss below, Mr. Rigsby's CAPM analysis should be disregarded due his selection of an unreasonably low risk-free rate, his use of an unadjusted historical risk premium, and his derivation of a cost of equity that is actually lower than the cost of debt to UNS Gas and the prevailing cost of debt to utilities in the capital markets. If the 5.82% midpoint

value of Mr. Rigsby's CAPM analysis is afforded the proper weight it deserves, this leaves the 11.4% point estimate obtained from Mr. Rigsby's DCF analysis as a more reasonable estimate of the cost of equity for UNS Gas.

Q. What are the main problems with Mr. Rigsby's use of the CAPM?

A. Mr. Rigsby's CAPM analysis suffers from the same flaws discussed previously in response to Staff witness David Parcell. Both witnesses used a risk-free rate that reflects the recent flight to quality in the capital markets. However, both witnesses also failed to adjust their historical market risk premiums to properly reflect this flight to quality. By failing to adjust the market risk premium to reflect the substantial increase in the cost of bearing risk, both Mr. Rigsby and Mr. Parcell significantly underestimated the cost of equity for the companies they examined. However, because of Mr. Rigsby's choice of an unrealistically low risk-free rate, the end result of these flaws is much more pronounced in Mr. Rigsby's testimony.

Q. Please discuss the risk-free rate selected by Mr. Rigsby.

A. As discussed on page 30 of his Direct Testimony, lines 6-9, Mr. Rigsby used an average of recent yields on a 5-year U.S. Treasury security to arrive at his risk-free rate of 1.87%. Due to the upward slope of the U.S. Treasury yield curve, Mr. Rigsby's use of a 5-year Treasury security instead of a longer-dated security served to reduce the risk-free rate to a much lower number than the 3.82% value selected by Mr. Parcell in his CAPM analysis and the 4.53% value used in my CAPM analysis, both of which were based on 20-year U.S. Treasury bond yields.

Q. What rationale did Mr. Rigsby offer for his selection of a 5-year U.S. Treasury security in arriving at a risk-free rate?

A. On page 30 of his Direct Testimony, lines 13-20, Mr. Rigsby offers the following explanation:

> While a shorter instrument, such as a 91-day T-bill, presents the lowest possible risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury instrument closely matches the investment period, or in the case of regulated utilities, the period that new rates will be in effect.

Q. Does this rationale hold any water?

A. No, it does not. Mr. Rigsby has confused the period that "new rates will be in effect" with the "investment period" for a common stock investment. As noted by Mr. Rigsby, a good argument can be made that an instrument that matches the investment period of the asset being analyzed should be used to derive the risk-free rate. In the case of a common stock which has no maturity date, and for which it is assumed that dividends are paid into perpetuity under the DCF model, the relevant "investment period" used by investors to value common stocks is a very long time period. Therefore, in the context of using the CAPM to estimate the cost of common equity capital, the relevant risk-free rate is the yield on long-term U.S. Treasury securities, and not the yield on intermediate-term securities as advocated by Mr. Rigsby.

Q. Please explain how Mr. Rigsby used the results of his CAPM analysis in arriving at his recommended 8.61% cost of equity.

A. As shown on page 32 of his Direct Testimony, Mr. Rigsby came up with a range of 5.26% to 6.39% for the cost of equity using the CAPM. The midpoint of this range, 5.82%, was

then averaged with the 11.4% cost estimate he obtained from the DCF model in arriving at his recommended cost of equity of 8.61%.

Q. Mr. Grant, have you ever been involved in a utility rate case where a witness used a cost of equity estimate as low as 5.82% to arrive at a recommended return on equity?

A. No. I first began working on utility rate cases in the late 1980s. During that period, up until I left the Public Utility Commission of Texas in 1995, I cannot recall ever seeing an estimated cost of equity that low. Additionally, since resuming my direct involvement in utility rate cases in the middle part of this decade, I cannot recall seeing a cost of equity estimate that low. In short, I am shocked that Mr. Rigsby would offer testimony that gives any weight at all to such a low number.

Q. Is it possible that utility equity investors would expect a return that is lower than the prevailing cost of debt for a utility?

A. No. Common shareholders stand behind bondholders in terms of their claims on the cash flows and assets of a company. Consequently, the risk borne by a common shareholder is much higher than that of a bondholder, resulting in a higher cost of equity capital relative to the cost of debt. The difference between the required return on equity and the required return on debt is often referred to the equity risk premium. Although I have read research papers that have contemplated the possibility of a negative equity risk premium, for example during periods of hyper-inflation or other extraordinary circumstances, the presence of such a phenomenon under current capital market conditions is simply implausible.

Q. Do you have any other comments on Mr. Rigsby's cost of equity analysis?

A. No, I do not.

III. ABILITY OF UNS GAS TO EARN ITS COST OF CAPITAL.

A. Rebuttal of Staff Witness David C. Parcell.

Q. What does Mr. Parcell have to say about UNS Gas' ability to actually earn its cost of capital?

A. Mr. Parcell's Direct Testimony does not say much in this regard. However, he makes several references to the importance of allowing a utility to earn a reasonable ROR, and on page 40 of his Direct Testimony, lines 12-14, he states that his cost of capital recommendation "provides the company with a sufficient level of earnings to maintain its financial integrity."

Q. What is the basis for Mr. Parcell's conclusion that his recommendation will result in a sufficient level of earnings for UNS Gas?

A. Mr. Parcell makes reference to a pre-tax interest coverage ratio calculated on Schedule 14 attached to his Direct Testimony. As discussed by Mr. Parcell on page 40 of his Direct Testimony, lines 14-16, he believes the referenced coverage ratio is consistent with a credit rating of BBB or higher. However, if Mr. Parcell's statements are read carefully, it is apparent that he is not offering an opinion as to whether or not UNS Gas will actually be able to achieve the level of earnings and pre-tax interest coverage portrayed on Schedule 14. Instead, he refers to the coverage ratio on Schedule 14 as "the pre-tax coverage that would result if UNS Gas earned my cost of capital recommendation." Importantly, Mr. Parcell *assumes* that UNS Gas will be able earn the 10.0% cost of equity he recommends, but offers no evidence that the Company will actually be able to do so.

Q. Does Mr. Parcell express an opinion regarding the importance of allowing a utility to earn its cost of capital?

A. Yes, based on the numerous statements found throughout his Direct Testimony on this subject, it appears that he attaches great importance to this regulatory goal. For example, on page 5 of his Direct Testimony, lines 15-17, he states that "From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments." Likewise, on pages 5-8 of his Direct Testimony, he devotes considerable attention to a discussion of the Hope and Bluefield decisions rendered by the U.S. Supreme Court, and makes a specific reference to the "end result" doctrine established by the Hope decision. As discussed by Mr. Parcell on page 7 of his Direct Testimony, lines 16-18, this "end result" doctrine maintains that "the methods utilized to develop a fair return are not important as long as the end result is reasonable." On this same page, lines 22-15, he goes on to state that "The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk." Finally, on page 47 of his Direct Testimony, in a discussion of the linkage between rate base and the cost of capital, Mr. Parcell states that "This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility." Based on these statements from Mr. Parcell's Direct Testimony, as well as his conclusion that his cost of capital recommendation "provides the company with a sufficient level of earnings to maintain its financial integrity," it appears on the surface that Mr. Parcell believes that UNS Gas should be provided with an opportunity to actually earn its cost of capital.

Q. Did Mr. Parcell offer any analysis regarding the Company's ability to earn its cost of capital?

A. No. Despite the fact that Staff is recommending a rate increase that is less than 50% of what UNS Gas has requested, and despite evidence presented in my Direct Testimony that the Company requires all of the rate relief requested in order to earn its cost of capital, Mr. Parcell merely assumes the Company will be able to do so.

Q. Has the Company been able to earn its cost of capital since its last rate increase was implemented in December 2007?

A. No. Despite having higher than expected sales due to an unusually cold first quarter, the Company realized an earned ROE of only 9.2% in calendar year 2008, versus an authorized ROE of 10.0% in UNS Gas' last rate case. For the twelve months ending March 31, 2009, the Company's earned ROE dropped to 7.2% as a result of less favorable weather and the impact of the economic recession on customer demands. As reflected on page 27 of my Direct Testimony, at the time of our rate filing the Company anticipated earning a ROE of 7.3% for calendar year 2009. Based on actual results through the first quarter of 2009, as well as a reduced sales forecast, the Company now anticipates earning a ROE of 7.2% in calendar year 2009.

Q. In light of the weakness in sales, has the Company revised its forecast of earnings in 2010 and beyond?

A. Yes. The table below, which is an updated version of the forecast presented on page 27 of my Direct Testimony, shows the projected earnings and ROE for UNS Gas assuming the Company is granted its full rate request and is allowed to implement new rates in December 2009:

($ Thousands)	2008 Actual	2009	2010	2011
Gross Margin	$55,424	$55,532	$64,975	$66,099
Operating Expenses	(34,757)	(37,222)	(40,592)	(42,499)
Operating Income	$20,668	$18,310	$24,383	$23,600
Other Income – Net	150	142	186	418
Interest Expense	(6,640)	(6,391)	(6,332)	(6,556)
Pre-Tax Income	$14,178	$12,061	$18,237	$17,461
Income Tax Exp.	(5,640)	(4,790)	(7,225)	(6,917)
Net Income	$8,538	$7,270	$11,013	$10,544
Ending Common Equity	$96,684	$103,948	$114,961	$120,233
Return on Avg. Equity	9.2%	7.2%	10.1%	9.0%

As my be seen in the table above, UNS Gas now projects that it will earn a ROE of only 10.1% in 2010 even if its rate request is granted in full and is implemented prior to January 2010. Even though the Company has trimmed its forecast of operating expenses and capital expenditures, the reduced sales outlook coupled with the continued use of an historical test year for rate setting purposes will make it very difficult for the Company to earn its cost of capital even if UNS Gas is granted the full rate increase it has requested. Based on this forecast, it should be apparent that the Company requires all of its requested rate increase in order for it to have any opportunity of earnings its cost of capital.

Q. Will UNS Gas have an opportunity to earn its cost of capital if Staff's revenue requirement is adopted?

A. No. The Company estimates that it will be able to earn an ROE of only 6-7% if Staff's revenue requirement is adopted.

Q. How did you arrive at an estimate of UNS Gas' earned ROE under Staff's revenue requirement?

A. This calculation is very straightforward. Since Staff's recommended rate increase is $6.1 million lower than the Company's requested increase, this represents the approximate difference in pre-tax earnings available to UNS Gas in the first full year under new rates. Applying a 39% composite income tax rate to this value produces an after-tax earnings difference of $3.7 million. Subtracting this amount from the forecasted earnings and ending common equity balance in the table above results in forecasted earnings of $7.3 million and an earned ROE of 6.8%, a level comparable to the Company's current level of earnings and the proposed cost of debt in this proceeding.

Q. When estimating the earned ROE resulting from Staff's revenue requirement, should the expenses and capital base of the Company also be adjusted in the forecast?

A. No. In making their reductions to UNS Gas' revenue requirement, Staff assumes that certain expenses and investments are somehow not needed for the provision of retail gas service. However, these expenses and investments do not disappear simply because Staff assumes they are not needed. The other adjustments Staff made to UNS Gas' revenue requirement relating to test year revenues, the cost of equity capital, and the ROR on FVRB also have no bearing on what the Company will be required to spend on operating costs and capital projects in the years to come. In the context of the "end result" test referenced by Mr. Parcell, the adjustments made by Staff to test year expenses and rate base have no relevance except for their impact on future operating revenues. It should be clear that in applying such a results-based test, it is the practical effect of Staff's recommendation on UNS Gas that should be considered, as opposed to a backward-looking analysis that is based on historical data and assumed spending reductions.

Q. Does Mr. Parcell's pre-tax coverage ratio analysis constitute an "end results" test?

A. No. For example, if a utility regulator is too aggressive with expense and rate base adjustments, a utility could be forced into bankruptcy – yet Mr. Parcell's approach would lead one to conclude that the bankrupt utility is financially healthy on an adjusted basis. Indeed, if Mr. Parcell were to apply the same approach he does in his testimony in this case, it appears he would testify that the bankrupt utility was able to attract debt and equity capital at reasonable rates and that it would be able to earn returns consistent with companies of similar risk. A test that shows a bankrupt utility is financially sound is no test at all.

Q. Based on the financial impact of Staff's rate recommendations, do you believe that the adoption of Staff's revenue requirement will result in earnings that are sufficient to support UNS Gas' financial integrity?

A. No, I do not. If Staff's revenue requirement is adopted, it is obvious that UNS Gas will not be provided with a reasonable opportunity to either earn its cost of capital or attract new capital on reasonable terms.

B. <u>Rebuttal of RUCO Witness William A. Rigsby.</u>

Q. What does Mr. Rigsby have to say about UNS Gas' ability to actually earn its cost of capital?

A. Like Mr. Parcell, Mr. Rigsby's Direct Testimony does not say much in this regard, despite making several references to the importance of providing a utility with an opportunity to actually earn its cost of capital. The closest Mr. Rigsby comes to opining on the prospective earnings of UNS Gas is a statement he makes on page 49 of his Direct Testimony, lines 15-22:

> I believe that my recommended cost of equity will provide UNSG with a reasonable rate of return on the Company's invested capital...As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

Mr. Rigsby's statement on page 9 of his Direct Testimony, lines 3-7, also touches on his belief regarding the Company's ability to earn a reasonable ROR:

> The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers.

Q. What financial analysis does Mr. Rigsby offer to support his conclusion that UNS Gas will be provided with a "reasonable rate of return"?

A. None whatsoever. Nowhere does Mr. Rigsby evaluate the Company's ability to actually earn its cost of capital under RUCO's rate recommendation. Instead, all he offers are blanket assurances that the ROR recommended by RUCO will meet the requirements of Hope and Bluefield, and that the Company will be provided with a reasonable ROR.

Q. Will UNS Gas have an opportunity to earn its cost of capital if RUCO's revenue requirement is adopted?

A. No. The Company estimates that it will be able to earn an ROE of only 5-6% if RUCO's revenue requirement is adopted. This ROE is so low that it even falls below the Company's 6.49% cost of debt that Mr. Rigsby recommends as reasonable.

Q. Based on the financial impact of RUCO's rate recommendations, do you believe that the adoption of RUCO's revenue requirement will result in earnings that are sufficient to support UNS Gas' financial integrity?

A. No, I do not. If RUCO's revenue requirement is adopted, it is obvious that UNS Gas will not be provided with an opportunity to either earn its cost of capital or attract new capital on reasonable terms.

IV. RATE OF RETURN ON FAIR VALUE RATE BASE.

A. Rebuttal of Staff Witness David C. Parcell.

Q. What does Mr. Parcell recommend regarding ROR on fair value?

A. Mr. Parcell's primary recommendation is that the Commission apply a 0% return on the portion of FVRB that exceeds the original cost rate base. Mr. Parcell refers to this portion of the FVRB as the "fair value increment." In other words, Mr. Parcell recommends no return at all on the fair value increment. Thus, the revenue requirement is entirely determined by the ROR on original cost. This approach is mathematically equivalent to the now-discredited "backing in" method formerly used by the Commission, where the revenue requirement was determined by applying the weighted average cost of capital to the original cost rate base, with a "fair value rate of return" being determined simply as a fall out number.

Q. Is Mr. Parcell's recommendation consistent with recent Commission decisions?

A. No. Mr. Parcell presented the same recommendation in the "Chaparral City" remand case.[5] The Commission did not adopt Mr. Parcell's recommendation in its remand order, Decision No. 70441. Mr. Parcell also repeated this recommendation in the recent

[5] Docket No. W-02113A-04-0616.

Southwest Gas rate case, and again the Commission did not adopt it in the Commission's rate order, Decision No. 70664. Thus, Mr. Parcell's recommendation has been rejected at least twice by the Commission. Indeed, even Staff seems to concede that this recommendation is inappropriate, as Staff's revenue requirement does not follow Mr. Parcell's primary recommendation.[6]

Q. What approach did Staff use in calculating its revenue requirement?

A Staff used an "alternative" recommendation proposed by Mr. Parcell. Mr. Parcell also presented this alternative recommendation to the Commission in the Chaparral City remand case. The Commission did not adopt his alternate recommendation in that case.[7]

The alternate recommendation being made by Mr. Parcell in this proceeding is also the same as the method he proposed in the recent Southwest Gas rate case. In that case, his proposal was adopted in a modified form by the Commission. However, in doing so the Commission noted that: (1) the Chaparral City remand order (Decision No. 70441) was not issued by the time of the hearing in the Southwest Gas case; (2) no party presented a method similar to the method approved in the Chaparral City case; and (3) the utility agreed to the basics of Mr. Parcell's approach, disputing only the method of determining the risk-free rate.[8] The Commission determined that for these three reasons the method approved in the Chaparral City remand order was not available in the Southwest Gas case.

These three reasons do not apply to this case: (1) the Chaparral City remand order is available for guidance; (2) we are presenting the method approved in that case; and (3) we do not concede the appropriateness of Parcell's alternative recommendation – indeed I strongly disagree with it. Thus, I believe that the Commission should follow the method

[6] See Direct Testimony of Dr. Thomas Fish, Schedule THF-A1, line 6 and footnote *.
[7] See Decision No. 70441 at 36-37.
[8] See Decision No. 70665 at 32-33.

recommended in the Chaparral City remand order, Decision No. 70441, or in the alternative, the method that was refined by the Commission Staff in Docket No. W-02113A-07-0551.

Q. What is your view of Mr. Parcell's alternative recommendation for calculating the ROR on FVRB?

A. First, as described above in Section III of my Rebuttal Testimony, it results in a revenue requirement that is simply too low to support UNS Gas' financial integrity. Second, it represents an unwarranted departure from the calculation methodology approved by the Commission in Decision No. 70441, as well as the modest refinement to that methodology recommended by Staff in Docket No. W-02113A-07-0551. Third, it is based on Mr. Parcell's belief that the fair value of utility property should be given little, if any, weight in setting retail rates. And finally, his choice of a 1.25% cost rate to apply to what he refers to as the "fair value increment" is arbitrary since it represents the midpoint of a fairly wide range of values (zero to 2.50%) and is unsupported by any analysis of the financial impact his recommendation would have on UNS Gas.

Q. What is the impact of Mr. Parcell's recommendation on UNS Gas' revenue requirement?

A. His decision to apply a 6.37% ROR to the Company's FVRB resulted in a substantial reduction to the overall revenue requirement. For example, had Mr. Parcell instead chosen the high end of his range, 2.50%, as the cost rate to apply to the "fair value increment" described in his testimony, he would have derived a ROR on FVRB of 6.70%:

	% of Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	36.56%	6.49%	2.37%
Common Equity	36.55%	10.00%	3.66%
Fair Value Increment	26.89%	2.50%	0.67%
Total	100.00%		6.70%

Alternatively, had Mr. Parcell used the same calculation methodology adopted by the Commission in Decision No. 70441, where the ROR on FVRB was derived by adjusting the cost of equity downward by the expected rate of inflation, he would have obtained a 7.25% ROR on FVRB using his 10.0% cost of equity capital and the 2.0% inflation rate referenced on page 50 of his Direct Testimony:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	8.00%	4.00%
Total	100.00%		7.25%

* Note: Modified cost of equity = 10.0% - 2.0% = 8.0%.

Finally, had Mr. Parcell used the same methodology recommended by Staff in Docket No. W-02113A-07-0551, in which both the cost of debt and cost of equity are adjusted by one-half of the inflation rate, he would have also obtained a 7.25% ROR on FVRB:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	50.01%	5.49%	2.75%
Common Equity	49.99%	9.00%	4.50%
Total	100.00%		7.25%

* Note: Modified cost of debt = 6.49% - 1.0% = 5.49%.
Modified cost of equity = 10.0% - 1.0% = 9.00%.

When applied to Staff's FVRB of $251.5 million, and adjusted by Staff's gross revenue conversion factor, these differences in the ROR on FVRB produce the following impact on UNS Gas' overall revenue requirement:

Difference between 6.70% and 6.37% ROR on FVRB
= $251.5 mil. x 0.33% x 1.6343
= <u>$1.36 mil.</u>

Difference between 7.25% and 6.37% ROR on FVRB
= $251.5 mil. x 0.88% x 1.6343
= <u>$3.62 mil.</u>

Q. Mr. Grant, in your Direct Testimony you proposed a 6.80% ROR on FVRB even though you demonstrated that UNS Gas could have supported a higher value of 7.30%. Is it your position that the ROR on FVRB in this proceeding should be limited to a maximum value of 6.80%?

A. No. This reduction was a voluntary measure. As described on page 30 of my Direct Testimony, the ROR of 6.80% was selected on the basis that this was the minimum value required to produce an overall revenue requirement that would allow UNS Gas an opportunity to earn its cost of capital and maintain its financial integrity. Due to the substantial cuts to the revenue requirement proposed by Staff and RUCO, and the possibility that those adjustments could be adopted by the Commission, the basis for limiting the proposed ROR on FVRB has dissipated. Therefore, the ROR on FVRB should be determined using the method approved in Decision No. 70441, or in the alternative, the method subsequently recommended by the Commission Staff in Docket No. W-02113A-07-0551.

Q. In light of the substantial revenue requirement adjustments recommended by Staff, what ROR would you recommend be applied to UNS Gas' FVRB?

A. I would recommend using a ROR that is consistent with the methodology used by the Commission in Docket No. 70441. As described in my Direct Testimony, this ROR would be equal to 7.30% if the Commission were to approve the Company's proposed cost of capital. Alternatively, as described above, this ROR would be equal to 7.25% if the Commission were to approve Staff's proposed cost of capital.

B. <u>Rebuttal of RUCO Witness Ralph C. Smith.</u>

Q. What is your general impression of Mr. Smith's testimony regarding the ROR on FVRB?

A. I found Mr. Smith's description of the various calculation methodologies and related impacts on UNS Gas' revenue requirement to be helpful. However, I was troubled by his lack of explanation regarding his choice of a 5.38% ROR on FVRB, a value that is only 0.01% higher than the methodology that gives zero weight to the Company's FVRB. As shown on page 1 of Schedule A attached to his testimony, this small increment of return would provides UNS Gas with only $38,000 of additional revenues, despite having a FVRB that is over $70 million higher than its original cost rate base ("OCRB").

Q. What explanation has Mr. Smith offered for his choice of a 5.38% ROR on FVRB?

A. The only explanation I could find is the "Evaluation" listed directly below the overall revenue requirement for each of the calculation methods listed on page 2 of Schedule A attached to his Direct Testimony. These evaluations range from "way too high" for the revenue requirement associated with Mr. Smith's "Calculation 1" methodology, to "too low" for the revenue requirement derived from Mr. Smiths "Calculation 3" and "Calculation 4" methodologies. As described in footnote [a] at the bottom of this same page, Mr. Smith also indicates that the recommended 5.38% ROR on FVRB was selected "based on informed judgment after reviewing OCRB and FVRB calculations." This opinion, rather than a detailed explanation of his analysis, is the only explanation Mr. Smith offered.

Q. In exercising his "informed judgment," did Mr. Smith consider the financial impact of his ROR recommendation on UNS Gas?

A. No, it does not appear that he did. Nowhere in his Direct Testimony, nor that of any other RUCO witness, could I find any analysis of how RUCO's revenue requirement would impact UNS Gas. Although RUCO witness William Rigsby does include a blanket statement in his Direct Testimony indicating that RUCO's recommended ROR on FVRB "meets the criteria" established in the *Hope* and *Bluefield* decisions (see page 9 of his Direct Testimony, lines 3-7), no substantive analysis was presented on this point by Mr. Rigsby or any other RUCO witness.

Q. In the executive summary attached to Mr. Smith's Direct Testimony he states that UNS Gas is effectively requesting a ROE of 12.58% on its OCRB. Is this true?

A. Yes and no. This statement is incorrect in the sense that UNS Gas developed its OCRB revenue requirement using the 11.0% cost of equity recommended in my Direct Testimony. However, this statement is also correct in a certain sense, since the Company's FVRB revenue requirement is higher than its OCRB revenue requirement. When this higher FVRB revenue requirement is expressed on an OCRB revenue requirement basis, the resulting return on equity is indeed higher.

Q. Does this mean that the Company is requesting "an excessive rate of return" as alleged by Mr. Smith in his executive summary?

A. No. This is simply the result of giving some weight to the Company's FVRB, which as discussed earlier is over $70 million higher than its OCRB.

Q. Will the Company have an opportunity to actually earn the 12.58% ROE that Mr. Smith has recommended?

A. No. As described earlier in my testimony, at best the Company can expect to earn a ROE of only 10.1%. This assumes that the Company's requested rate increase is granted in its entirety.

Q. Do you have any other comments regarding the ROR on FVRB that Mr. Smith is recommending?

A. My only remaining comment is that the ROR values obtained from each of his calculation methodologies are based, at least in part, on the unreasonably low cost of equity estimate recommended by RUCO witness William Rigsby. As such, all of the ROR values and associated revenue requirements "evaluated" by Mr. Smith are much too low, irrespective of which methodology is ultimately approved by the Commission.

V. CARRYING COST ON PURCHASED GAS ADJUSTOR BALANCE.

A. Rebuttal of Staff Witness Robert G. Gray.

Q. Mr. Grant, what comments do you have in response to the Direct Testimony filed by Staff witness Robert Gray?

A. My comments are focused only on the interest rate to be applied to balances of under- and over-recovered gas costs under the Company's PGA. Due in part to the lack of readily available published data showing the monthly average for 3-month LIBOR, Mr. Gray has expressed a preference for continued use of the rate on 3-month financial commercial paper published by the Federal Reserve. Although the Company's preference would be to use the 3-month LIBOR rate plus 1.0% to reflect the cost of short-term borrowing for UNS Gas, the Company would also be willing to use the financial commercial paper rate

favored by Mr. Gray plus a 1.0% credit spread. Although 3-month LIBOR has typically been somewhat higher than the rate on 3-month financial commercial paper, this rate differential is typically not very large. Exhibit KCG-16 shows the recent rates for each of these interest rate series, along with the above-referenced cost of short-term borrowing to UNS Gas.

Q. In his Direct Testimony Mr. Gray commented that, contrary to a statement in your Direct Testimony, the Federal Reserve does not publish rates for 3-month LIBOR. Is Mr. Gray's comment correct?

A. Yes. Unfortunately, the statement on page 33 of my Direct Testimony, lines 17-18, should have referred to LIBOR rates published by the British Bankers Association ("BBA") and by the Wall Street Journal, and not the Federal Reserve. And since the BBA data is only published free of charge on a lagged historical basis, the Wall Street Journal would probably be the best source of timely data for 3-month LIBOR rates. If this benchmark rate is ultimately used in the calculation of the PGA interest rate, UNS Gas would be willing to compile the daily rates for 3-month LIBOR and submit them for review by Staff, along with a simple calculation of the monthly average rate and documentation showing that UNS Gas is still subject to a 1.0% credit spread on its revolving credit facility. As mentioned above, however, UNS Gas would also be willing to use the 3-month financial commercial paper rate currently being used, plus the 1.0% credit margin applicable to borrowings under the UNS Gas credit facility.

Q. Do you have any more comments on Mr. Gray's Direct Testimony?

A. My only remaining comment is that by requesting a change to the PGA interest rate, the Company is only trying to recover its reasonable costs. Such a minor change to the PGA interest rate should have no impact whatsoever on the gas procurement practices of UNS Gas.

Q. Mr. Grant, does this conclude your Rebuttal Testimony?

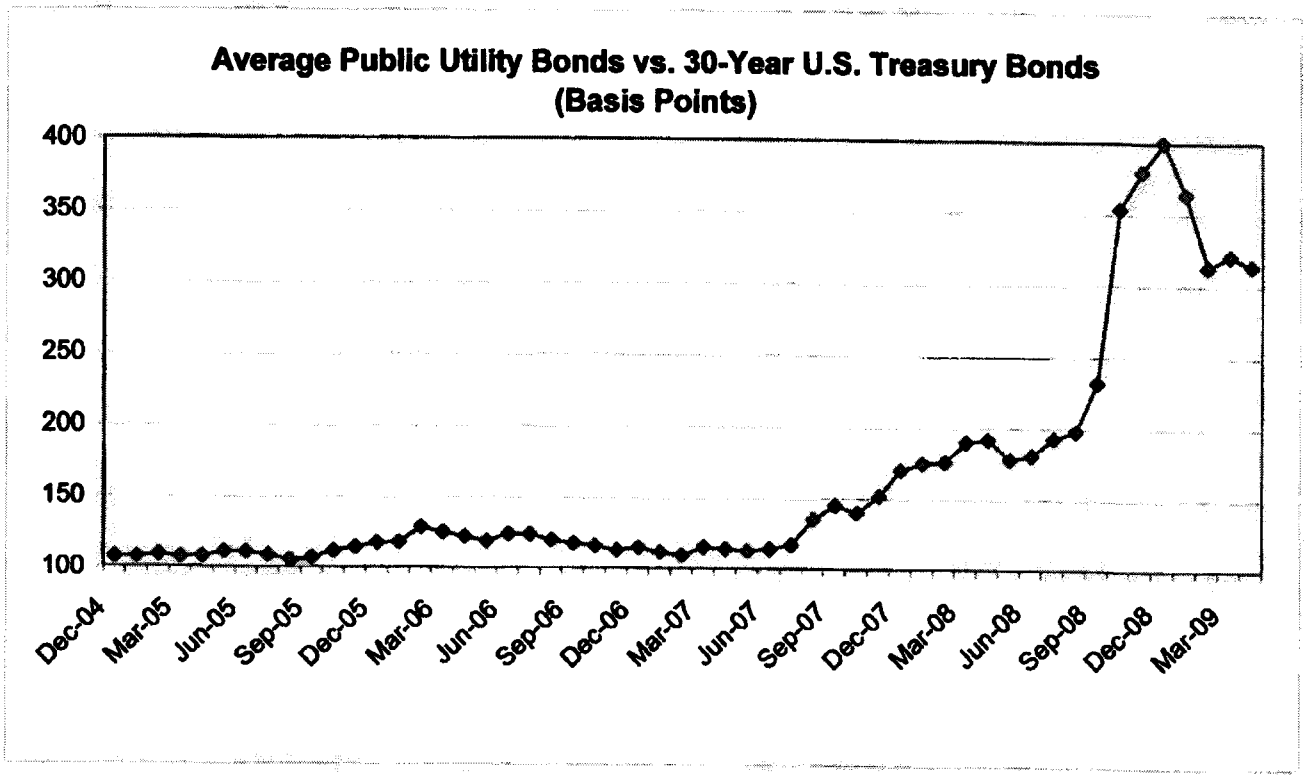
A. Yes, it does.

EXHIBIT

KCG-14

Exhibit KCG-14

UNS Gas, Inc.
Public Utility Bond Credit Spreads



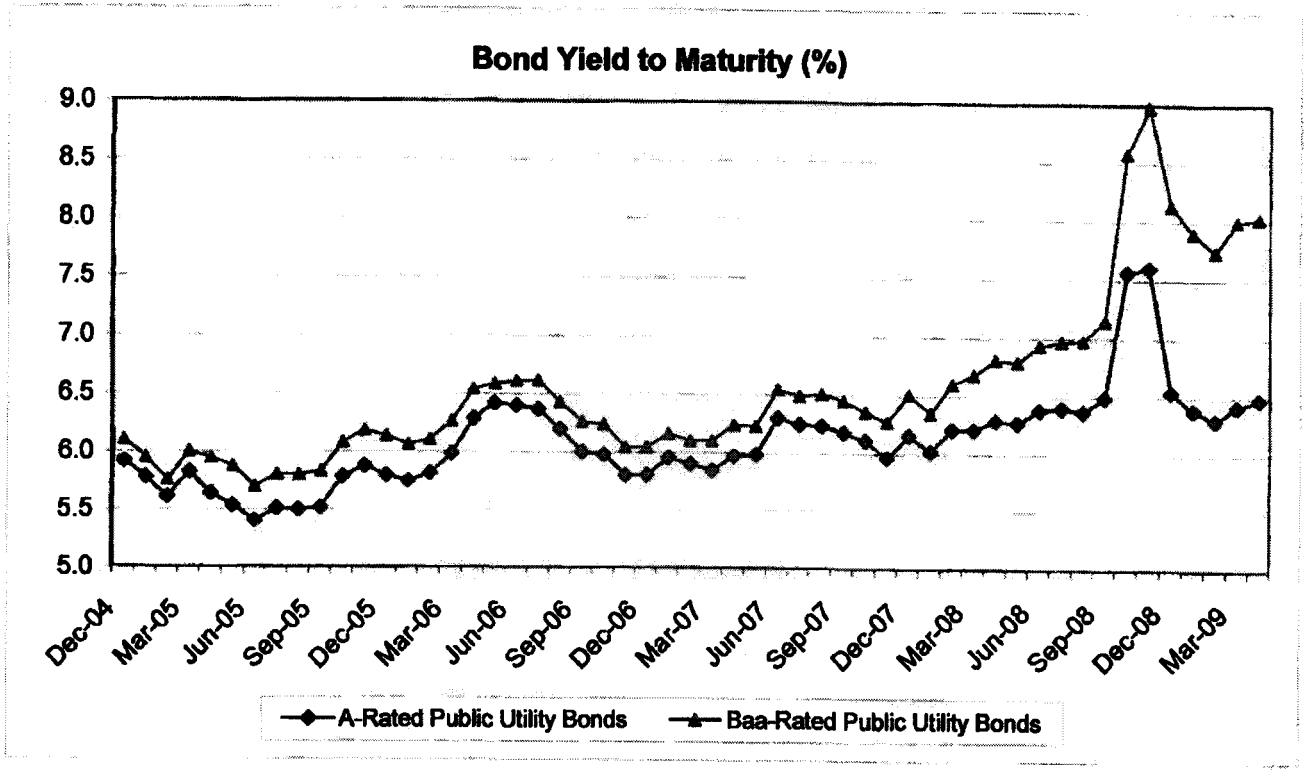
Sources: Public Utility bond yields are from Mergent Bond Record. 30-Yr. U.S. Treasury bond yields are from Mergent Bond Record (Dec 2004 - Jan 2006 data) and the Federal Reserve Board of Governors Web site (www.federalreserve.gov, Feb 2006 - Apr 2009 data).

EXHIBIT

KCG-15

Exhibit KCG-15

UNS Gas, Inc.
Public Utility Bond Yields for A-Rated and Baa-Rated Utilities



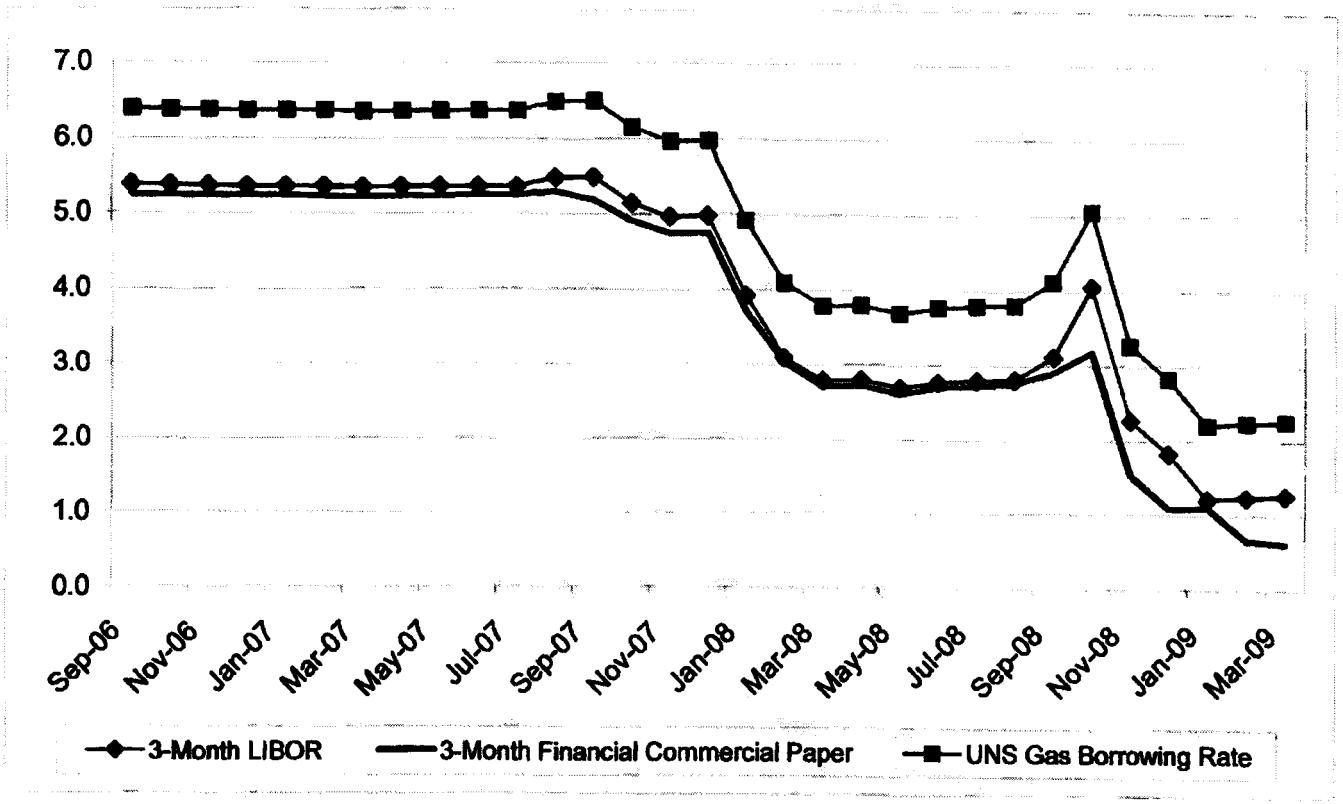
Source: Public Utility bond yields are from Mergent Bond Record

EXHIBIT

KCG-16

Exhibit KCG-16

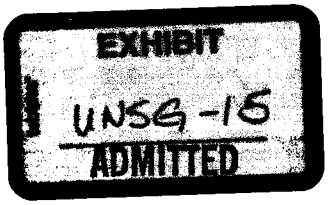
UNS Gas, Inc.
Short-Term Interest Rates (%)



Source: Financial Commercial Paper rates are from the Federal Reserve Board of Governors Web site (www.federalreserve.gov). LIBOR rates are from the British Bankers' Association Web site (www.bba.org.uk).

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

August 5, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona.

Q. Did you file Direct Testimony and Rebuttal Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc.

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

A. The purpose of my Rejoinder Testimony is to respond to portions of the surrebuttal testimony filed by Arizona Corporation Commission Staff ("Staff") witnesses David C. Parcell, Thomas H. Fish and Robert G. Gray, as well as portions of the surrebuttal testimony filed by Residential Utility Consumer Office ("RUCO") witnesses William A. Rigsby and Ralph C. Smith.

II. RESPONSE TO STAFF WITNESS DAVID C. PARCELL.

Q. What aspects of Mr. Parcell's Surrebuttal Testimony will you address in this Rejoinder Testimony?

A. My comments will focus on Mr. Parcell's characterization of recent developments in the capital markets and his assertion that UNS Gas is somehow seeking a guaranteed return on capital.

Q. What does Mr. Parcell have to say regarding recent developments in the capital markets?

A. On page 4 of his Surrebuttal Testimony Mr. Parcell once again makes reference to the recent "flight to safety" that has taken place in the debt and equity markets. However, despite the increase in observed bond yields and large sell-off in common stocks, Mr. Parcell continues to reject the notion that the cost of capital for utilities has increased. Instead, he reiterates his belief that the flight to safety reflects more of an "availability of capital" problem as opposed to a "cost of capital" problem.

Q. Is this a realistic view of the capital markets?

A. No. This view could only hold water if one were to suspend the laws of supply and demand in the capital markets. It is simply unrealistic to believe that the cost of capital for utilities could remain unchanged when the amount of capital made available to utilities has been dramatically reduced through a massive flight to safety. The simple fact of the matter is that required yields on U.S. Treasury securities plummeted while required yields on utility bonds rose dramatically, especially for lower-rated utilities such as UNS Gas. At the same time, even relatively stable sectors such as the gas utility industry suffered large declines in stock prices. Mr. Parcell's decoupling theory, wherein the cost of capital remains unaffected by the "availability of capital," is a phenomenon that is contrary to both basic economic principles and empirical market data.

Q. What does Mr. Parcell have to say with regard to the Company's ability to earn its cost of capital?

A. Not much. However, on page 7 of his Surrebuttal Testimony, he offers the following observation:

> Mr. Grant seems to be taking the position that the cost of capital authorized by a commission should be regarded as a "guarantee" but this is not the case. Utility investors have no more "right" to a guaranteed return than do its ratepayers to a "right" to employment, maintenance of their housing values, and an increasing value of their retirement accounts and other investments.

Q. Is this a fair characterization of your testimony?

A. No, it is not. All the Company is seeking is a reasonable opportunity to earn its cost of capital. Even if UNS Gas' rate proposal were adopted in its entirety, the Company would still be exposed to variability in sales, inflationary cost pressures, changes in tax policies, shifting capital markets, new regulatory mandates and a host of other potential risks to its financial outlook. Additionally, as demonstrated in my Rebuttal Testimony, the Company forecasts that it would still not be able to earn its 11.0% cost of equity even if the Commission were to grant the entire rate increase being sought by UNS Gas. Under the circumstances, I find Mr. Parcell's characterization of my testimony to be very misleading.

III. RESPONSE TO STAFF WITNESS THOMAS H. FISH.

Q. Mr. Grant, what portion of Dr. Fish's Surrebuttal Testimony do you care to address?

A. My comments focus on Dr. Fish's discussion of the Company's working capital requirements, and in particular, the reasonableness of the credit terms that existed between UNS Gas and its sole natural gas supplier, BP Energy, during the test year. Other aspects of Dr. Fish's Surrebuttal Testimony will be addressed by other UNS Gas witnesses.

Q. What did Dr. Fish have to say about the credit terms that existed between UNS Gas and BP Energy during the test year?

A. On page 4 of his Surrebuttal Testimony, Dr. Fish expressed an opinion that the credit terms were "not realistic" and "not representative of normal credit terms." He goes on to state that "UNS Gas has the discretion to obtain more favorable terms and conditions from another supplier," and that UNS Gas customers should not have to bear the incremental cost of these credit terms.

Q. What aspect of these credit terms does Dr. Fish criticize?

A. He criticizes the making of payments to BP Energy twice per month instead of on a monthly basis as is customary. His main problem with the acceleration of payments is that the Company's working capital requirements are higher than they would otherwise be.

Q. Did the Company have any alternatives it could have pursued in lieu of making accelerated payments?

A. Yes, but neither of these alternatives would have been cost effective. One of these alternatives would have involved the posting of cash collateral with BP Energy for an extended period of time. The other alternative would have required the issuance of a bank letter of credit in the favor of BP energy. Both of these alternatives would have been more costly than the accelerated payment plan.

Q. Do you agree with Dr. Fish that UNS Gas had the discretion to obtain more favorable terms from another supplier?

A. No. During the test year, BP Energy was a full-requirements supplier to UNS Gas. Only under very limited circumstances would the Company have been permitted to purchase gas from another provider. Since the expiration of that full-requirements contract in mid-

2008, the Company has started purchasing gas from other suppliers. However, it should be noted that other suppliers are not providing generous amounts of credit to UNS Gas. BP Energy still provides more trade credit to UNS Gas than any of the other gas suppliers the Company is now doing business with.

Q. Do you agree with Dr. Fish that the credit terms extended by BP Energy were "not realistic" and "not representative of normal credit terms"?

A. No. As stated above, BP Energy has extended more trade credit to UNS Gas than any other supplier. Credit terms are negotiated between a buyer and seller as part of the contracting process. Since BP Energy was the Company's sole gas supplier during the test year, and since UNS Gas' credit profile is weaker than most gas utilities, it should not be surprising that UNS Gas would bump up against this credit limit during peak periods of gas usage. While the acceleration of payments to third party providers is not a very common practice, in the case of UNS Gas is was a cheaper alternative relative to posting cash collateral or providing a letter of credit.

Q. Do you agree with Dr. Fish that the Company's customers should not be responsible for the incremental cost of providing credit support?

A. No. The Company makes no profit on the sale of natural gas procured in the wholesale market for retail customers. Since the Company is providing a valuable gas procurement service that benefits its retail customers with no mark-up, it is hard to understand why Dr. Fish believes that credit support costs incurred for gas procurement should not be recouped by the Company.

IV. RESPONSE TO STAFF WITNESS ROBERT G. GRAY.

Q. What comments do you have in response to the Surrebuttal Testimony filed by Staff witness Robert Gray?

A. Mr. Gray cites the same reasons discussed in his Direct Testimony for denying the Company's proposal to change the interest rate on bank balances under the Puchased Gas Adjustor ("PGA") rate mechanism. However, on page 2 of his Surrebuttal Testimony, he also implies that under the Company's proposal, the proposed interest rate would somehow be applied differently to under- and over-recovered balances of purchased gas costs.

Q. Is the Company proposing to apply a one interest rate to over-recovered PGA bank balances and a different interest rate to under-recovered PGA bank balances?

A. No. Under UNS Gas' proposal, the same rate would be applied to both under- and over-recovered bank balances. And since the proposed interest rate is higher than the rate currently in place, customers would actually benefit from this proposal at the present time due to the presence of an over-recovered PGA bank balance at UNS Gas.

V. RESPONSE TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. What comments do you have on the Surrebuttal Testimony filed by RUCO witness William Rigsby?

A. I will confine my comments to Mr. Rigsby's use of the Capital Asset Pricing Model ("CAPM") to derive an estimate for the cost of equity capital. In his Surrebuttal Testimony, Mr. Rigsby continues to defend his use of the CAPM, which resulted in a ridiculously low cost of equity estimate of 5.26% to 6.39%. He also goes on to provide an alternative CAPM analysis that produces an even lower range of 4.91% to 6.25%.

Although Mr. Rigsby makes many technical arguments in support of his analysis, the end result produced by his CAPM analysis is simply unrealistic.

Q. Please explain why the results obtained from Mr. Rigsby's application of the CAPM are unrealistically low.

A. This point was initially addressed on page 20 of my Rebuttal Testimony, where I described how it is unrealistic to expect the cost of equity capital to be lower than the cost of debt for any given company. As described in his Direct Testimony, Mr. Rigsby agrees with UNS Gas that the Company's embedded cost of debt is 6.49%. He also points out on page 17 of his Surrebuttal Testimony that required returns on Baa/BBB rated utility bonds were recently quoted at 6.85%. Therefore, using either the embedded cost of debt for UNS Gas or the current market rate of debt for similar rated utilities, the CAPM results obtained by Mr. Rigsby would imply the presence of a negative equity risk premium (i.e., a cost of debt that exceeds the cost of equity).

Q. Does Mr. Rigsby's Surrebuttal Testimony address the feasibility of a negative equity risk premium?

A. Yes. Page 16 of his Surrebuttal Testimony, lines 18-23, contains the following question and answer:

> 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 UNS Gas.

Based on Mr. Rigsby's own testimony regarding the cost of debt and the lack of a negative equity risk premium, it is apparent that the results he obtained from the CAPM are unrealistically low and should therefore be afforded zero weight in determining the Company's cost of equity.

VI. RESPONSE TO RUCO WITNESS RALPH C. SMITH.

Q. What aspects of Mr. Smith's Surrebuttal Testimony will you respond to?

A. My comments are focused on his discussion of the appropriate rate of return ("ROR") on fair value rate base ("FVRB"). In particular, I will respond to his statements regarding the appropriate use of financial forecasts in a rate proceeding, and his assertion that UNS Gas' rate proposal represents an unwarranted burden on the Company's customers.

Q. How does Mr. Smith characterize your use of financial forecasts in this proceeding?

A. On page 12 of his Surrebuttal Testimony, lines 10-12, he infers that I am using financial forecasts as "some kind of a surrogate for a future test year" or as "some kind of test of the reasonableness of the parties' differing recommendations."

Q. Is this characterization accurate?

A. No. Although I am using the results of a financial forecast to gauge the reasonableness of the rate increases recommended by each of the parties to this proceeding, I am certainly not using the forecast as a "surrogate" for a future test year.

Q. Please explain.

A. As discussed by Mr. Smith as well as Staff witness David Parcell, the Commission has some discretion in setting the ROR on FVRB. In recognition of this discretion, the rates of return on FVRB recommended by the witnesses in this proceeding vary widely. In order to gauge the reasonableness of these widely divergent rates of return, and the end result arising from each party's revenue requirement, it is important to examine the financial impact these recommendations will have on UNS Gas. The only meaningful way do this, given that new rates will not be in place until late 2009 or early 2010, is to examine a financial forecast for the period that new rates will be in effect. That is the

reason I included a financial forecast for UNS Gas in both my Direct and Rebuttal Testimony. Without this information, I am not sure what basis the Commission would have for adopting one value over another in its determination of a reasonable ROR on FVRB. Alternatively, the Commission could adopt the same calculation methodology approved for Chaparral City Water Company in Decision No. 70441. However, it is apparent that there is no agreement between the Company, Staff and RUCO on what would constitute a reasonable ROR on FVRB in this proceeding.

Q. On pages 3 and 4 of his Surrebuttal Testimony, Mr. Smith discusses the criteria that he believes should be applied in determining a reasonable ROR on FVRB. Do you agree with the criteria applied by Mr. Smith?

A. No, I do not. While the Company is certainly sympathetic to the plight of its customers in such a tough economic environment, the basis for Mr. Smith's recommendation is clearly one-sided. No consideration is given to the Company's need to recover its cost of providing service and the opportunity to earn a reasonable rate of return on its capital investment. Instead, Mr. Smith refers to any increment of revenue requirement over and above that produced by an original cost rate base as a "fair value difference" and an "extra revenue increase" that should be as close to zero as possible. He goes on to characterize the "fair value difference" derived from the methodology adopted in Decision No 70441 as "burdening" to ratepayers and resulting in a rate increase that is "not warranted" for UNS Gas. In short, the only criteria being applied by Mr. Smith in selecting a ROR on FVRB is the minimization of rates to UNS Gas customers.

Q. Is the requested ROR on FVRB and corresponding rate increase "unwarranted" as Mr. Smith claims?

A. No, it is not. The Company's cost of service is clearly higher than the revenues produced under current rates. Although the current economic environment is indeed very

challenging, and a rate increase would likely be viewed as an unwelcome burden by many of the Company's customers, the simple fact of the matter is that UNS Gas shareholders have also been burdened by below-market rates of return on their capital, even during periods of relative economic prosperity. The approach being advocated by Mr. Smith is decidedly asymmetrical. Under his approach, during poor economic times such as these, it is perfectly acceptable for a public utility to earn less than its cost of capital. However, during more prosperous times, the best a utility can expect to do is to earn its cost of capital, and not a penny more. Such a policy would clearly not be in the long-term best interest of UNS Gas or its customers, as it would serve to reduce the amount of capital and credit made available to the Company, and increase the cost of whatever capital and credit that is made available.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

EXHIBIT
UNSG-116
ADMITTED

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABL E 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-____

Direct Testimony of

Dallas J. Dukes

on Behalf of

UNS Gas, Inc.

November 7, 2008

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is One South Church Ave., Tucson, Arizona, 85702.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Manager of Rates and Revenue Requirements for Tucson Electric Power Company ("TEP" or the "Company"). As Manager of Rates and Revenue Requirements, I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UniSource Energy Corporation ("UniSource Energy"), including UNS Gas, Inc. ("UNS Gas" or the "Company").

Q. Please describe your background and work experience.

A. I hold a Bachelors of Science degree in Accounting from Indiana University. I am also a Certified Public Accountant. I have over seventeen years experience as an accountant within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for

approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your Direct Testimony?

A. I am supporting the Company's request for a rate increase by sponsoring Schedules A-1, A-2, and A-5, Schedules B-1, B-2, B-3, B-4 and B-5, and the pro forma accounting adjustments on Schedule B listed below:

(i) Acquisition Discount;

(ii) Griffith Power Plant Facilities ("Griffith Plant");

(iii) Build-Out Plant Write-Down;

(iv) Golden Valley Pipeline;

(v) Post Test Year Non-Revenue Producing Plant;

(vi) Customer Advances Adjustment

(vii) Working Capital.

I am also sponsoring Schedules C-1, C-2 and C-3, and the pro forma accounting adjustments reflected on Schedules C listed below:

(viii) Griffith Plant Operations;

(ix) Golden Valley Pipeline Operations;

(x) Purchased Gas Cost and Gas Cost Revenue;

(xi) Negotiated Sales Program ("NSP") Revenue and Gas Cost;

(xii) Payroll Expense;

(xiii) Payroll Tax Expense;

(xiv) Pensions and Benefits;

(xv) Incentive Compensation;

(xvi) Rate Case Expense;

(xvii) Bad Debt Expense;

(xviii) Miscellaneous Expenses;

(xix) Normalize Outside Legal Expense;

(xx) CARES Expense;

(xxi) CARES Regulatory Asset Amortization; and

(xxii) Y2K Amortization;

(xxiii) DSM Revenue & Expense.

Q. Please describe the information contained in summary Schedule A-1?

A. Schedule A-1 provides a summary of the increase in revenue requirement that UNS Gas is seeking through a rate increase in this case. Lines 1 through 8 of Schedule A-1 present the data utilized in determining the Company's revenue requirement. The data is presented pursuant to three valuation methodologies: (1) original cost; (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value. Fair value is determined by adding together the original cost and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods when determining the fair value amount. This method of determining the fair value is consistent with prior Commission practice.

The test-year that the Company utilized for this rate case is the twelve months ending June 30, 2008. As set forth in Schedule A-1, the original cost rate base is $182 million and the RCND rate base is $329 million. Under standard Arizona Corporation Commission ("Commission") practice, the fair value rate base is considered to be $256 million.

Schedule A-1 supports a finding that UNS Gas presently has an operating income deficiency of $5.8 million and is requesting an increase in revenues of $9.5 million. This

results in an average 6% increase to a customer's total bill compared to test year revenues, inclusive of gas costs. The effect on the fixed monthly and delivery charges on an average customer's bill will be an increase in those components of approximately 19% compared to test year revenues, excluding gas cost recovery. However, this 19% increase is only associated with a portion of the customer's total bill. Therefore, assuming the remaining portion of a customer's bill, the gas cost, is equivalent to test year levels, the customer will see an average overall increase of approximately 6% to his total bill. Lines 11 through 18 of Schedule A-1 present how the revenue increase would be allocated among UNS Gas' customers by class.

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the reasonable and prudently incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test-year that reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that are expected to exist during the time that resulting rates may be in effect. The revenue requirement calculation also contains a component that is intended to afford the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the respective regulatory authority.

Pro forma adjustments are made to recorded test-year amounts that are not required for the provision of service or that are not representative of the levels expected to occur during the period in which the new rates will be in effect. Such adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Annualization adjustments are made to reflect the full, twelve-month revenue or expense level of certain components of operating income. They are typically computed using end-of-test-year quantities and the most current known and measurable prices and rates. Examples in this case include restating test-year operating revenues to reflect customer levels at the end of the test-year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test-year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test-year.

Normalization adjustments reflect that the recorded test-year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test-year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a test-year level of revenues or expenses is not representative of what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of outside legal expense.

Q. Were the pro forma adjustments that you are sponsoring in your Direct Testimony prepared by you or under your supervision?

A. Yes, they were.

III. RATE BASE ADUSTMENTS.

i. Acquisition Discount.

Q. Please explain the Acquisition Discount adjustment.

A. Effective August 11, 2003, UniSource Energy acquired from Citizens Communications Company ("Citizens") its remaining gas assets located in Arizona. The Commission approved this acquisition in Decision No. 66028 (July 3, 2003) pursuant to a Settlement Agreement. This adjustment is necessary in order to properly reflect the discount, or negative acquisition premium, authorized by the Commission when UniSource Energy acquired Citizens. Decision No. 66028 calls for the use of a $30.7 million "negative acquisition premium" (see page 8, lines 17 through 22 of the Decision) in the calculation of rate base for ratemaking purposes to reflect this lower purchase price.

Q. Is an acquisition adjustment normally appropriate?

A. No. Normally original cost rate base is just that "original cost" and under Commission rules, the original cost of utility property is the cost "at the time it is first devoted to pubic service."[1] In the case of an asset sale, the assets will have been devoted to service before the sale. Thus, the sale does not affect the original cost of the assets, either positively or negatively. In other words the relevant cost is the "cost of [the] property to the person first devoting it to public service."[2] Thus, an acquisition adjustment is normally not appropriate. However, UniSource Energy did agree to the specific negative acquisition

[1] Arizona Administrative Code ("AAC") R14-2-102.A.6
[2] A.A.C. R14-2-103.A.3.e

adjustment noted above (*i.e.* the acquisition discount adjustment). This pro forma adjustment is necessary so that the acquisition adjustment is limited for ratemaking purposes to the specific value agreed to by the Company and approved by the Commission.

Q. Please explain further.

A. UniSource Energy actually paid $50.1 million less than the original cost for the gas assets acquired from Citizens. In accordance with United States Generally Accepted Accounting Principles ("GAAP"), this amount had to be shown on the Company's books as a negative acquisition adjustment. This GAAP acquisition discount is larger than the acquisition discount approved by the Commission as described above. Normally, an acquisition discount would not be considered for ratemaking purposes at all. However, in this case, the discount agreed to by the Company must be recognized. Essentially, this pro forma adjustment takes the GAAP discount and reduces it to the value of the discount authorized by the Commission. Put another way, the GAAP discount must be reduced for ratemaking purposes, which increases rate base.

Q. Please explain the accounting details further.

A. When I say the "value" of the agreed upon discount, I mean the $30.7 million figure stated in the 2003 Settlement Agreement, less amortization. The amortization has been calculated through June 30, 2008. Amortization reflects the fact that the assets which were purchased do not have an infinite life. Pursuant to the Settlement Agreement approved by the Commission, the amortization rate is the same as the depreciation rate for corresponding plant accounts. According to Commission and the Federal Energy Regulatory Commission ("FERC") directives, the acquisition adjustment was a credit to accumulated depreciation.

Q. Is the Acquisition Discount adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas rate case order, Decision No. 70011 (November 27, 2007) (hereinafter sometimes referred to as "the last UNS Gas Rate Order").

ii. <u>Griffith Plant.</u>

Q. Please explain the Griffith Plant adjustment.

A. This adjustment removes from Plant in Service the cost of facilities that connect the Griffith Plant with the El Paso Natural Gas and Transwestern Pipeline Company interstate pipelines. Such facilities were constructed by and are owned by UNS Gas. The Griffith Plant costs are recovered pursuant to a specific contract between UNS Gas and the owners of the Griffith Plant. The facilities, revenue and expenses relating to the Griffith Plant are excluded from rate base and revenue requirements for the purposes of general retail ratemaking.

Q. Is the Griffith Plant adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

iii. <u>Build-Out Plant Write-Down.</u>

Q. Please explain the Build Out Plant Write-Down adjustment.

A. In Decision No. 66028, the Commission approved a Settlement Agreement which included "an additional $10 million permanent disallowance to gas rate base … to

recognize excessive costs associated with Citizens' Build-Out Program." (See page 8, lines 21-22 of the Decision.) This adjustment takes the required adjustment to December 31, 2001 rate base and separates that adjustment into components for gross plant in service and accumulated depreciation. Then the adjustment also quantifies additional depreciation provided through June 30, 2008, – removing the respective plant and accumulated depreciation from rate base.

Q. Is the Build Out Plant Write-Down adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

iv. <u>Golden Valley Pipeline.</u>

Q. Please explain the Golden Valley Pipeline ("GVP") adjustment.

A. This adjustment removes from Plant in Service the majority of the cost of the GVP facilities that connect the Black Mountain Generating Station ("BMGS") with the Transwestern Pipeline Company interstate pipeline. Such facilities were constructed by and are owned by UNS Gas. The majority of the GVP costs are recovered pursuant to a specific contract between UNS Gas and the owner of the BMGS.[3] This portion of the facilities, revenue and expenses relating to the GVP, in accordance with the agreements approved in Decision No. 70186, (February 27, 2008), are excluded from rate base and revenue requirements for the purposes of general retail ratemaking.

[3] The BMGS is currently owned by UniSource Energy Development Company ("UED"), a subsidiary of UniSource Energy.

Q. What amount of the facilities, revenue and expenses related to GVP is being included in rate base and revenue requirements?

A. Per the agreement between the owner of BMGS and UNS Gas, approximately **REDACTED%** of the costs are being recovered from the owner of BMGS and thus only **REDACTED%** is being included in rate base and revenue requirements in this proceeding. This amount is being included for capacity made available to serve UNS Gas retail customers in the area of the pipeline.

Q. Are there retail customers currently being served by the GVP?

A. Yes. The Kingman prison is currently being served by the distribution line and is providing for partial recovery of the annual estimated cost of the GVP included in rate base, and thus the Company's proposed revenue requirements. It is also expected that the prison will essentially double its consumption in the 1st quarter of 2010 with the completion of its expansion. In addition there is a factory that is expected to connect to the distribution line within the next few months.

Q. Are there provisions in the contract that allow for the allocation of cost to be recovered from UED to be re-evaluated and adjusted?

A. Yes. The contract includes a provision that in five years from the date of the agreement, the allocation will be re-evaluated. Any cost not being recovered from new retail customers taking service from the GVP distribution line will be re-allocated to the owner of the BMGS. Essentially, if the new customers do not hook-up, then those cost will be recovered from the owner of BMGS for the remainder of the contract and the retail customers of UNS Gas will be held harmless.

v. **Post Test Year Non-Revenue Producing Plant.**

Q. Please explain the Post Test Year Non-Revenue Producing Plant adjustment.

A. This adjustment is being made to aid the Company in having a more reasonable opportunity to earn its authorized return by accelerating the recovery of investments made prior to the end of the test year into plant that will not produce additional revenues beyond the test year adjusted amount. These investments were not in service by the end of the test year, but will be in service when rates established in this case go into effect. These are investments in items like transportation equipment, general plant, replacements and relocations of existing facilities.

Q. Is the Company advocating that the Commission should allow the recovery of and on plant investment expended by the end of the test year, but not in service?

A. Yes. The Commission should allow UNS Gas to recover such costs. The Company has made investments to serve existing customers and will not see any additional revenue directly related to these investments until the time the investments are reflected in rate base within a rate proceeding. The inclusion of post test year non-revenue producing plant in rate base will help the Company to begin recovering its investment and an opportunity at earning a reasonable return in a more equitable time frame. If this current case follows an expected course, new rates will go into effect in December 2009 at the earliest. Based upon the circumstances of this matter in which Staff required at least six months of actual rates billed within the test year - a new rate case could not be filed until October of 2010, with rates most likely not effective until January 2012. So the recovery of and on investments actually made prior to the end of the test year, but not technically in service, will not produce additional revenues until January 2012, in other words, over 3 ½ years after the investments were made to serve existing customers.

vi. **Customer Advances Adjustment.**

Q. Please explain the Customer Advances Adjustment.

A. This adjustment is made to more accurately and properly reflect the actual circumstances of the Company for the amount of customer contributed capital available as of the end of the test-year. At the end of the test-year, UNS Gas had customer advances totaling $11.8 million, and of those advances, $0.6 million had already been "spent" on projects not in service as of the end of the test year. The Company is proposing that the test-year reduction to rate base for advances be reduced by the $0.6 million for the amount of advances already spent on projects not included in rate base and thus no longer available to the Company as zero cost customer contributed capital. Because those specific projects are not reflected in rate base as of the end of the test-year, the Company is being denied the return on and return of investments it actually has made in plant in service as of the end of the test year based on a false general assumption that customer advances as of the end of the test year are directly related to plant in rate base and/or represent zero cost capital available to the Company. And because (i) those projects are not reflected in rate base and (ii) and the contributed capital for those investments is no longer available to the Company, the Company's opportunity to earn a reasonable return is reduced by such treatment.

vii. **Working Capital.**

Q. What is Working Capital?

A. Working Capital is generally viewed as investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service.

Q. What are the items of Working Capital for which the Company requests a return?

A. The components of Working Capital that the Company is requesting be included in rate base are:

(i) Materials and Supplies;

(ii) Prepayments; and

(iii) Cash Working Capital.

As more fully explained later in my Direct Testimony, the amounts requested for rate base inclusion for the materials and supplies and prepayments are based on test-year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of the Lead-Lag Study Methodology, to be covered in-depth later herein.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, it is indicative that there is an additional investment for which a return is warranted, and thus, the amount is added to rate base. If the computation produces a negative result, there is an implicit non-investor funding of Cash Working Capital, requiring a rate base deduction.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two pieces. First, as indicated on page 2 of Schedule B-5, the recorded end-of-test-year balances for Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases.

Second, Working Capital is adjusted for the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested working capital amounts in rate cases.

The focal point of all lead-lag studies is the "point of service." That is the instant in time at which customers receive service and, coincident therewith, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" if the payment occurs after the cost benefit). Cash Working Capital

reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As may be seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted test-year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item. Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. How was the average revenue lag computed?

A. The revenue lag is comprised of three distinct parts: the service lag, the billing lag, and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under twelve monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed

based on actual meter read dates and bill mailing schedules used by UNS Gas during the test-year.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. That lag was determined by computing the average accounts receivable turnover for six months during the test-year. The accounts receivable turnover measures the average time during which a balance remains in accounts receivable and is computed by dividing the sum of the daily ending balances of accounts receivable by the sum of revenues billed and charged to accounts receivable during the study month.

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall result of the lead-lag study?

A. The study showed that there was negative cash working capital and a corresponding decrease was made as a pro forma adjustment to rate base.

<u>CARES Regulatory Asset.</u>

Q. Please explain the CARES Regulatory Asset.

A. There is no specific adjustment on Schedule B for a CARES regulatory asset; the amount is within the test year opening balance. In Decision No. 70011, the Commission ordered that UNS Gas cease the deferral of costs related to the CARES program upon approval of the new rates established in that Decision. However, the Decision did not address the recovery of deferred CARES costs already incurred by UNS Gas and not yet recovered.

Prior to the Commission's order to cease deferral accounting, the actual discounts given to customers and other allowable CARES program costs were deferred. This leaves only the portion actually recovered in existing rates recognized as an expense. This left the difference between the amount spent and the amount being recovered on the balance sheet as a regulatory asset. In that particular case, the deferred CARES cost included in rate base as a regulatory asset was $107,477 as of December 31, 2005.

The balance of those deferred CARES program costs (as of the elimination of the deferred accounting process) is now $492,590, as of June 30, 2008. The Company is requesting the recovery of these costs incurred for the CARES program, deferred per Commission Decision No. 59875 (October 31, 1996) and reaffirmed in subsequent Commission Decisions until Decision No. 70011 ordered the Company to cease the treatment.

IV. OPERATING INCOME ADJUSTMENTS.

viii. Griffith Plant Operations.

Q. Please explain the Griffith Plant Operation's adjustment.

A. This adjustment removes the revenues and expenses associated with serving the Griffith Plant. The Griffith Plant costs are recovered pursuant to a specific contract between UNS Gas and the owners of Griffith Plant. This special contract was approved by the Commission in Decision No. 61835 (July 21, 1999). Pursuant to that Decision, the plant, revenue, and expenses are excluded from rate base and revenue requirements for the purpose of general retail ratemaking.

ix. **Golden Valley Pipeline Operations.**

Q. Please explain the Golden Valley Pipeline Operation's adjustment.

A. This adjustment removes the revenues and expenses associated with the GVP. The GVP costs are recovered pursuant to a specific contract between UNS Gas and the owners of BMGS. This special contract was approved by the Commission in Decision No. 70186 (February 27, 2008). Pursuant to that Decision, the plant, revenue, and expenses are excluded from rate base and revenue requirements for the purpose of general retail ratemaking.

x. **Purchased Gas Cost and Gas Cost Revenue.**

Q. Please explain the Purchased Gas Cost and Gas Revenue adjustment.

A. This adjustment removes the base cost of gas charged to the customers, PGA rates charged to the customers and approved surcharges charged to customers during the test-year. This adjustment has zero impact on operating income as there is no profit associated with the recovery of purchased gas expenditures.

xi. **Negotiated Sales Program Revenues and Gas Cost.**

Q. Please explain the Negotiated Sales Program Adjustment.

A. The Negotiated Sales Program ("NSP") allows the Company to participate in the competitive bidding process of its transportation customers who are seeking to purchase gas supplies for their own use in accordance with a transportation tariff. The Company, in accordance with Decision No. 59399 (November 28, 1995), credits the PGA bank account for 50% of the sales margin, unless the NSP customer is a transportation

customer who was a bundled sales customer any time during the most recent three-year period. In that case, the Company credits the PGA bank 100% of the sales margin.

The test-year income statement reflects revenues received and the gas cost incurred to serve NSP customers excluding the sales margin recorded into the PGA bank. The adjustment removes all remaining revenues and purchased gas expense from the sale of natural gas to NSP customers. This is necessary because the remaining sales margin is the portion to be retained by the Company.

Q. Is the Negotiated Sales Program Revenue and Gas Cost adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

xii. <u>Payroll Expense.</u>

Q. Please explain the Payroll Expense adjustment.

A. The Payroll Expense adjustment is intended to reflect in operating expenses an annualized level of salaries and wages based on current rates of pay and the number of employees on the UNS Gas payroll at the end of the test-year. That annualized level is then adjusted for the known pay rate increase that will go into effect January 1, 2009 and the estimated pay rate increase that will go into effect January 1, 2010. The pay rate increase as of January 1, 2010, will be known prior to the close of the record in this proceeding and prior to rates going into effect based on a decision in this proceeding. If necessary, the rate can be updated if it varies significantly from the estimate.

Q. Is the Payroll Expense adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas rate order with the exception of the request for the 2010 pay rate increase. However, that treatment is consistent with the treatment approved in the last two Southwest Gas rate filings, (Decision Nos. 64172 (October 30, 2001) and 68487 (February 23, 2006)), UNS Electric's last rate filing (Decision No. 70360 (May 27, 2008) and the settlement agreement in the current Tucson Electric Powers Company's rate filing.

xiii. <u>Payroll Tax Expense.</u>

Q. Please explain the Payroll Tax Expense adjustment.

A. The Payroll Tax Expense adjustment was computed in a manner similar to, and consistent with, the payroll adjustment. An annualized level of payroll taxes was computed using current payroll tax rates, the same end-of-test-year employee levels and current salary rates that were used in the payroll adjustment.

Q. Is the Payroll Tax Expense adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

xiv. **Pension and Benefits.**

Q. Please explain the Pension and Benefits adjustment.

A. The Pension and Benefits adjustment is intended to reflect in operating expenses a level of pension and benefits expense reflecting the end-of-test-year work force, current pension and benefit costs, and a normal level of business activity. The employee benefits covered by this adjustment include pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs.

Q. Is the Pension and Benefits adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

xv. **Incentive Compensation.**

Q. Please explain the Incentive Compensation adjustment.

A. Incentive compensation is an integral part of the Company's compensation and benefits program. The Company's incentive compensation program is calculated on specific corporate performance, and is designed to award non-union employees for their contributions to the Company. The goals evaluate many facets of the organization, including several customer or core goals, an operational cost containment goal, and a financial performance goal, all of which ultimately benefit UNS Gas' customers. The customer or core goals include measurements of system reliability, customer response time, and safety. The goals of financial performance and operational cost containment ensure employees are focused on the bottom line and encourage employees to manage costs that they can control by gaining efficiencies or by realizing synergies.

These Company wide goals are pushed down to the individual non-bargaining employee level and put into individual performance plans that provide measurable incentives for employees and put a portion of their individual pay at-risk. The amount of dollars available is determined based on Company wide results, but individual payments are determined based on individual accomplishments, thus those that perform at the highest levels can be rewarded accordingly. Payments are made to employees either late in the first quarter or early in the second quarter of the following year.

The adjustment is calculated by taking the average of the incentive compensation expense for the past three years and adjusting the amount reflected in test-year operating expenses to that level. Since the incentive compensation payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes thereon.

Q. Does this cash based incentive compensation program result in employee salaries and wages in excessive of market?

A. No. When combined with the employees' base salaries, the total cash compensation is actually below the median of market, based on the most recent benchmark studies.

Q. Is the Incentive Compensation adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in a similar manner as was "partially" approved by the Commission in the last UNS Gas Rate Order.

Q. What do you mean by "partially" approved in the last Rate Order?

A. The cash-based short-term incentive plan expense that was approved in the last rate case was 50% of the pro forma expense amount proposed by the Company. The Commission

ruled that the program benefited shareholders and customers equally and therefore the expense should be shared equally.

Q. Do you agree with the Commission's prior decision to reduce the cash based incentive plan of UNS Gas by 50%?

A. No, I do not. The Commission did *not* rule that the costs themselves or the program were imprudent or that they did not benefit the customers of UNS Gas. If the Commission finds that the costs are prudent and that the program benefits customers, it should allow *full* recovery of the cost based on the adjustment proposed by the Company.

xvi. <u>Rate Case Expense.</u>

Q. Please explain the Rate Case Expense adjustment.

A. The Rate Case Expense adjustment addresses the outside costs already incurred, and expected to be incurred, in connection with this rate case. This amount is an estimate of the anticipated final cost and will be updated before this proceeding concludes. The adjustment amortizes the balance to expense over three years. This is the approximate time period between when UNS Gas filed this rate case and when the next rate case will likely occur. The adjustment also reflects the collection of the anticipated remaining balance of rate case expense allowed to be recovered in Decision No. 70011. That remaining balance will also be amortized over the anticipated life of rates in this case.

xvii. <u>Bad Debt Expense.</u>

Q. Please explain the Bad Debt Expense adjustment.

A. Bad Debt Expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized test-year operating revenues, and the average

percentage of actual account write-offs experienced during the past three years. This method of calculating bad debt expense is consistent with past Commission accepted practice.

Q. Is the Bad Debt Expense adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

xviii. <u>Miscellaneous Expenses.</u>

Q. Please explain the Miscellaneous Expense adjustment.

A. This adjustment removes test-year expenses that should not be included in revenue requirements because they are for out-of-period activity, not reflective of test-year activity and/or should not be recovered from customers. Also included in this adjustment is an increase to test year postage expense to reflect the postage rate increase that went into effect May 12th, 2008.

xix. <u>Normalize Outside Legal Expense.</u>

Q. Please explain the adjustment to Normalize Outside Legal Expense.

A. This adjustment is being made to reflect a three-year average of outside legal costs. Legal costs by their nature are for primarily "individual" non-recurring activities. In this case, the test year activity is actually fairly reflective of a normal and recurring level, prior to adjustment, but the test year contained $310,000 in outside legal costs related to the last UNS Gas rate case filing that were disallowed recovery of and thus written off within the test year. Once that adjustment is made the test year level is only $84,000,

which is not reflective of normal and recurring levels. In 2005, 2006 and 2007 the Company spent $488,000, $439,000 and $242,000 respectively, on outside legal costs, excluding UNS Gas rate case activity. That results in a three-year average of $390,000 which is reflective of normal and recurring levels and is consistent with expected spending levels.

Q. Is the Normalization of Outside Legal Expenses adjustment consistent with the last UNS Gas rate case, Docket No. G-04204A-06-0463?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Gas Rate Order.

xx. <u>CARES Expense.</u>

Q. Please explain the CARES Expense adjustment.

A. The CARES Expense adjustment is necessary to remove the activity in the test-year based on the prior deferred accounting treatment. As I discussed earlier, the deferred accounting treatment ceased as of December 1, 2007, along with the implementation of the rates, pursuant to Commission Decision No. 70011. The proper revenue levels for CARES activity are adjusted through the Rate Case Revenue Annualization adjustment, sponsored by Company witness, D. Bentley Erdwurm. To reflect the impact of that event in this rate filing, it is also necessary to remove the test-year CARES amortization expense. By doing these things, the test-year is adjusted to reflect the currently approved CARES accounting treatment to insure that revenue requirements do not include the recovery of discounts to CARES customers as an expense and test-year revenues properly reflect the actual billings to customers net of the CARES discounts.

However, it is necessary to add back to test-year expenses an amount reflective of normal and recurring advertising expenses associated with the program. In the past, these expenses were deferred as incurred and only passed through the income statement based on the recovery rate approved in rates charged to customers. Since that is no longer the method of recovery or accounting, it is proper to reflect it in test-year adjusted expenses.

xxi. <u>CARES Regulatory Asset Amortization.</u>

Q. Please explain the CARES Regulatory Asset Amortization adjustment.

A. The CARES Regulatory Asset Amortization adjustment is necessary to allow the Company to recover costs incurred prior to the change in accounting treatment for the CARES program. The Company is requesting recovery of the deferred costs over the life of the rates to be set in this proceeding, and estimated to be three years.

xxii. <u>Y2K Amortization.</u>

Q. Please explain the Y2K Amortization adjustment.

A. The Y2K Amortization adjustment is to remove the test-year amortization expense for recovery of Y2K costs that will be fully recovered by the time rates set in this proceeding go into effect.

xxiii. <u>Demand-Side Management ("DSM") Revenue & Expense.</u>

Q. Please explain the DSM Revenue & Expense adjustment.

A. This adjustment excludes from test year revenue and expenses the activity directly related to the DSM adjustor mechanism approved in Commission Decision No. 70011 (November 27, 2007).

V. SUMMARY OF SCHEDULES.

i. A Schedules.

Q. Have you described Schedule A-1 earlier in your Direct Testimony?

A. Yes. Again, Schedule A-1 is a summary of the increase in revenue requirement that UNS Gas is seeking as a rate increase in this case.

Q. Please describe the information contained in Schedule A-2.

A. Schedule A-2 presents a summary of the results of operations for the test-year and two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 set forth the summary of operations for the years ending December 31, 2006 and December 31, 2007, and the test-year ending June 30, 2008. Schedule A-2 also presents projected results of operations for the year ending June 30, 2009 under the headings "present rates" and "proposed rates".

Q. Please describe the information contained in Schedule A-5.

A. Schedule A-5 presents statements of changes in financial position for the years ending December 31, 2006 and December 31, 2007, the test-year ending June 30, 2008 and the projected year ending June 30, 2009.

ii. B Schedules.

Q. Please describe the information contained in Schedule B-1.

A. This schedule summarizes the elements of UNS Gas' rate base on both a net recorded original cost and RCND basis as of June 30, 2008, along with the pro forma adjustments to rate base. Rate base is comprised of net utility plant, certain regulatory assets, and

working capital, with deductions from rate base for ADIT, customer advances for construction and customer deposits.

Q. What is shown on Schedules B-2, B-3and B-4?

A. Schedule B-2 shows the pro forma adjustments to the original cost rate base. The information presented includes the actual per-books balances at the end of the test-year, pro forma adjustments, and the adjusted balances. Schedule B-3 provides the same detail by functional account classifications as shown in Schedule B-2, except that it is shown on an RCND basis. Schedule B-4 shows the plant in service accounts on an RCN and RCND basis.

Q. Please explain Schedule B-5.

A. This schedule summarizes the various elements of working capital that the Company is requesting for inclusion in rate base in this rate case.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

iii. <u>C Schedules.</u>

Q. Please describe the Company's "C" Schedules in its filing.

A. Schedules C-1 through C-3 present the development of the net operating income component of revenue requirements submitted for Commission consideration in this rate case filing.

Q. Please explain Schedule C-1.

A. Schedule C-1 shows the actual Income Statement for the twelve months ending June 30, 2008, the test-year in this case. It also summarizes the effect of the proposed pro forma adjustments to recorded operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedule C-2?

A. Schedule C-2 presents the detailed pro forma adjustments that reflect the full annual impact of operating changes, annualizations, normalizations, and other adjustments made to revenues and expenses.

Q. What is the purpose of Schedule C-3?

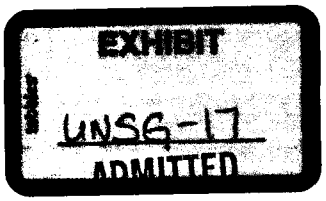
A. Schedule C-3 contains the development of the Gross Revenue Conversion Factor. That factor is used to convert the computed test-year return deficiency to an equivalent annual revenue increase amount. It effectively recognizes that there will be additional bad debt expense and income taxes associated with any adjustment to annual revenue levels.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rebuttal Testimony of

Dallas J. Dukes

on Behalf of

UNS Gas, Inc.

July 8, 2009

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Exhibits:

DJD-1 Comparison of the Parties' Position regarding Revenue Requirement

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Dallas Dukes. My business address is One South Church Avenue, Tucson, Arizona.

Q. Did you file Direct Testimony in this proceeding?

A. Yes

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Gas, Inc.

Q. Which Commission Staff and/or Intervener testimony do you address in your Rebuttal Testimony?

A. I address certain adjustments that Staff Witness Dr. Thomas H. Fish ("Dr. Fish") recommends in his Direct Testimony. I also address several adjustments that Residential Utility Consumer Office ("RUCO") witness Mr. Ralph C. Smith ("Mr. Smith") proposes in his Direct Testimony. While I agree with some of their adjustments, a significant number of adjustments made by Staff and RUCO are inappropriate and other adjustments are not supported by the evidence in this case. In this testimony, I explain why the Commission should reject these Staff and RUCO adjustments as they would not result in just and reasonable rates. I further explain why UNS Gas' revenue requirements, expenses, and adjustments are reasonable based on the evidence presented in this matter.

Q. Have you revised any of the adjustments that you sponsored in your Direct Testimony?

A. Yes, I have. I have made the following changes to the following adjustments that originally appeared in my Direct Testimony:

Working Capital: This adjustment to rate base is revised from $97,967 to $2,183,948 to reflect the correct purchased gas payment lag for the primary purchased gas vendor of UNS Gas and to reflect other pro forma adjustments. As a result of Staff's analysis, it came to light that UNS Gas was paying its primary purchased gas vendor twice a month because of credit limitations as opposed to its previous practice of only once a month. The Company revised its lead lag study to reflect that fact. Because of this change in payment terms for such a material portion of the Company's operating cost, the Company is actually paying vendors in advance of receiving the funds from its customers. This results in a positive working capital adjustment as opposed to the essentially neutral balance originally filed by the Company.

Rate Case Expense: This adjustment to operating expenses is revised from $200,000 to $141,667. The revised adjustment now matches Staff's proposed adjustment.

Fleet Fuel Expense: This adjustment to operating expense is revised from $0.00 to $(51,258) to reflect a three year average for Fleet Fuel Expense. This adjustment is necessary to normalize the test year level of expense using fixed, known and measurable information. The test year reflected and average cost of about $3.35 per gallon and the three year average is $3.06 per gallon which is more representative of current prices being incurred by UNS Gas and the expected cost to be incurred over the life of the rates established in this case.

Income Taxes: This adjustment to operating expense is revised from $(824,391) to $(808,257) to reflect the other pro forma adjustments.

Other than those adjustments (and the flow through impacts of those revisions), I reiterate the adjustments in my Direct Testimony.

Attached to my Rebuttal Testimony is Exhibit DJD-1, which is a spreadsheet that sets forth a comparison of the positions of the parties on the Revenue Requirement and their related adjustments. The spreadsheet also identifies the Company's revised position on its proposed adjustments.

Q. How do those revisions affect the Revenue Requirement?

A. Given these revised adjustments, our revenue requirement could increase as much as $145,766 on an original cost basis above the amount requested in the Application. However, as indicated in Exhibit DJD-1, the Company is not requesting a revenue requirement higher than proposed in its Application.

II. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Post Test Year Non Revenue Plant in Service.

Q. Do any of the parties disagree with the Company's inclusion of Post Test Year Non Revenue Plant in Service within rate base?

A. Yes. Both Staff's witness, Dr. Fish, and RUCO's witness, Mr. Smith, objected to including Post Test Year Plant in rate base.

Q. What is the basis for Dr. Fish and Mr. Smith's removal of the Company's Post Test Year Non Revenue Plant in Service adjustment?

A. Both Dr. Fish and Mr. Smith assert that the investment in the Post Test Year Plant must have been made to improve the system, thus reducing operating expenses. Mr. Smith also argues that the plant will be used to serve additional customers. Mr. Smith further asserts that the inclusion of Construction Work in Progress ("CWIP") requires compelling reasons to stray from Commission's normal practice of excluding CWIP. However, UNS Gas has not proposed including CWIP, so Mr. Smith's comments on CWIP are not relevant.

Q. Do you agree with Dr. Fish or Mr. Smith's adjustments that remove the Company's Post Test Year Non Revenue Plant in Service from rate base?

A. No. UNS Gas is requesting the inclusion in rate base of investments made as of the end of the test year in transportation equipment, general plant, replacement of services, and replacement of mains and relocation of facilities as that plant is now in service. Further, the purpose of these investments is to serve existing customers and these investments are made regardless of any additional customers ever being added to the system. And previous Commission decisions have included non-revenue producing post-test year plant in rate base, including Decision Nos. 65350, 66849, 67279, 68176 and 68864.

In the prior UNS Gas rate case, (Decision No. 70011 (November 27, 2007)), the Commission rejected UNS Gas' request for post-test year plant, noting that we made no attempt to segregate revenue-producing plant from non-revenue producing plant. In this case, we directly responded to this concern by limiting our request for post-test year plant to non-revenue producing plant. However, Staff and RUCO now both imply that because any investment in plant would result in reduced expenses, without citing any empirical evidence to support that assertion, any investment in plant simply cannot be considered "non-revenue producing." Under their analysis, non revenue producing Post Test Year

Plant would never be included in rate base, which is simply inconsistent with prior Commission decisions. Staff and RUCO provide no data or analysis to support their speculative allegations of reduced expenses.

Q. How did UNS Gas determine which plant was revenue-neutral?

A. The Plant accounting group and operational personnel of UNS Gas reviewed the projects and indentified investments that had been made in projects that would not produce additional revenue and that would have been invested in regardless of customer growth.

Q. What plant is included in the Company's proposed Post Test Year Plant?

A. For example, we included communication equipment, vehicles, tools, power equipment and natural gas detector equipment, which are all necessary to serve the existing customer base. We also include service and main replacements to ensure safe and reliable service to our existing customers.

Q. When did the Company make the investments in these projects?

A. The Company completed its investments in these projects before the end of the test year. The projects were simply not in service by the end of the test year – but they are, or will be, in service when rates resulting from this proceeding become effective.

B. <u>Customer Advances.</u>

Q. What is the basis for Dr. Fish and Mr. Smith's removal of the Company's Customer Advances adjustment?

A. Their primary arguments for exclusion of the Company's adjustment is that Customer Advances are non-investor supplied capital and that is the required treatment based on the sample schedule B-1, Commission rule A.A.C R 14-2-103.

Q. Do you agree with Mr. Smith's statement that customer advances are non-investor supplied capital?

A. Yes. That is exactly why they should be deducted from rate base at some point – so that the Company does not earn a return on investments it does not make. In other words, advances should neither increase nor decrease rate base – the net impact should be zero.

However, Staff and RUCO recognize the advances (the deduction from rate base) much earlier than the addition to plant in service (the addition to rate base). It is this mismatch that I disagree with. Under Staff's and RUCO's approach, because the advances are recognized too soon, and the result is that pre-existing rate base is reduced by the amount of the advance. Thus, Staff's and RUCO's rate bases doe not accurately reflect UNS Gas' level of investment.

Q. Can you provide an example?

A. Yes. Assume a utility has a rate base of $100,000,000 at a point in time ("Day One"). On Day Two, the utility receives an advance of $10,000,000 for new plant for a new development. One year later (i.e., on Day 367), the utility spends the full amount of the advance on the new plant. The new plant facilities are then placed into service following another year (i.e., on Day 732). The utility adds no other plant between Day One and Day 732. Under Staff's and RUCO's approaches, at Day One, the utility's rate base is $100,000,000. On Day Two, the utility's rate base drops to $90,000,000 – even though the utility's investment in rate base has not changed. Ten million dollars in existing rate base is just wiped out. This $10,000,000 reduction to pre-existing investment remains in place until the plant funded by the advances is placed into service on Day 732. At that point, the utility's rate base finally goes back to $100,000,000 – where it should have been all along.

Q. In your example, wouldn't the Company have the use of the $10,000,000 from Day 2 through Day 367 as non-investor capital?

A. Yes. And during that period it would be appropriate to recognize the portion to the advance not used as "zero" cost capital or even as a reduction in rate base to assure that the non investor supplied capital is being properly recognized. But the Company is requesting differing and fair treatment for the period between Day 367 and Day 732. A test year established in that period is where the mismatch takes place. The advance is already spent, so there is "NO" zero cost capital and the new facility is not in rate base. That is when the Utility is only getting rate base treatment for $90,000,000 when it should properly be getting rate base treatment for $100,000,000.

Q. Can't the Company avoid this problem by selecting a different test year?

A. No. In the simplified example above, the utility could avoid the problem only by selecting a test year ending after Day 732. But in reality, UNS Gas is constantly receiving advances, investing those advances in specific projects, and adding related plant. In other words, the receipt of advances is not a one-time event – it is a constant flow. Thus, there is no test year that UNS Gas could select that would avoid this problem.

Moreover, any suggestion that UNS Gas could avoid the problem by selecting its test year ignores the fact that Staff rejected UNS Gas' originally proposed test year and then allowed UNS Gas to use the current test year instead.

Q. Is there support in Commission decisions for the Company's approach?

A. Yes. In Decision No. 69914 (Sept. 27, 2008)(at page 29, lines 7-13), the Commission allowed Arizona-American Water Company similar treatment for contributions associated with hook-up fees pertaining to a specific surface water treatment plant.

C. Cash Working Capital.

Q. Did any of the parties propose changes to the Company's cash working capital calculation?

A. Yes. Dr. Fish reduced cash working capital based on his review of certain payment lags. He identified certain purchased gas payment lags for an individual vendor that were approximately half the payment cycle time of the other payments made by that vendor. Dr. Fish assumed these shorter payment lags were an anomaly and he adjusted the payment lags associated with those particular certain purchased gas payments to reflect a payment period of 35 days. Staff believed — incorrectly — that the 35 day pay period is more reflective of expected pay cycles based on historical payment patterns.

Q. Was Dr. Fish correct in his assumption?

A. No. The payment lag is actually much shorter then the 35 days used by Staff. In fact, the payments made to that vendor early in the test year were not reflective of payment terms later in the test year or of the current payment terms. The Company's payment terms were altered during the test year because of credit limitations. The vendor now requires the Company to make payments twice a month and those payment requirements continue today and for the foreseeable future. Therefore, Dr. Fish's adjustment to payment lags is factually incorrect and should not be adopted.

Q. Have you revised your Cash Working Capital adjustment?

A. Yes. In the Company's original filing, the new payment terms were only partially reflected in the Company's lead lag study. The changed payment schedule remains in place and is therefore a "known and measurable" change. Thus the Company is making an alternative adjustment in its rebuttal filing to fully reflect all purchased gas payments to that vendor with the proper payment lags.

D. Reconstruction Cost New Depreciated ("RCND").

Q. Do you have any comments on the RCND study discussions by Staff and RUCO?

A. Staff recommends the use of the Company's RCND study as submitted. Dr. Fish incorrectly implies in his Direct Testimony (at page 13, lines 1-11) that the Company took an extremely conservative approach in deriving its RCND study in the last rate case to keep the value of the RCND down. In fact, if the present RCND study was done in this case consistent with the prior case, the Company would have presented an RCND value of approximately $16 million greater than the one filed in my Direct Testimony. Therefore, the Company took a more conservative approach in this filing when compared to the previous filing.

RUCO did not object to the Company's RCND study, but did object to the Company's RCND value calculated for the adjustment "Post Test Year Non Revenue Plant in Service". The Company agrees with RUCO on that point and has revised its RCND calculation to reflect it.

III. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Payroll and Payroll Tax Expense.

Q. Did Staff or RUCO object to the Company's payroll adjustments?

A. Staff did not object to the Company's payroll adjustments in their Direct Testimony. RUCO proposed the exclusion of a portion of the Company's payroll adjustment. Mr. Smith (at page 56) took exception to the Company increasing test year annualized payroll for the wage increase that will take effect January 2010.

Q. What are Mr. Smith's reasons for excluding the January 2010 increase from the adjustment?

A. Mr. Smith believes that the increase is too far from the end of the test year and not known at this time. He essentially is making the same argument that RUCO witnesses made in each of the last three Southwest Gas filings that were ultimately rejected by the Commission.

Q. Do you agree with Mr. Smith's rationale?

A. No. The rates in this case are not likely to go into effect until January of 2010 at the earliest and will be in effect for the 2010 calendar year. The increase is being applied to employee levels as of the end of test year and therefore is not creating any mismatch of revenue and expenses. At this time we know the increases attributable to the portion of the workforce that are classified and have contracts in place. As for the unclassified employees, 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.

Q. Has such requested treatment been approved by this Commission?

A. Yes. For example, this treatment is consistent with the last UNS Electric rate case, Decision No. 70360 (May 27, 2008), and the most recent Southwest Gas Rate Case, Decision No. 70665 (December 24, 2008).

B. Incentive Compensation Expense.

1. Performance Enhancement Program ("PEP").

Q. Did Staff or RUCO reduce the pro forma PEP cost contained within the Company's requested revenue requirements?

A. Yes. Both Dr. Fish and Mr. Smith proposed that the pro forma level of PEP expense be reduced by half on the basis that the program benefits both shareholders and customers and thus should be shared equally.

The Company strongly disagrees with the "who benefits" analysis as a tool for what percentage of recovery to be afforded to the Company. That same type of analysis could be applied to any number of expense items. For example, payroll expense for operation personnel – the customers clearly benefit from employees operating and maintaining the system to provide safe reliable service – but the shareholders benefit as well as employees keep the system operational so the business can generate sales and make a profit for the owners. Should the payroll cost of operational employees be proportioned based on who benefits?

The decision to allow recovery should be based on whether the costs are prudently incurred, reasonable and if the costs are incurred to provide reliable service to customers. If those criteria are all met, then the cost should be fully recoverable, not partially. Neither Staff nor RUCO contend that the overall compensation, including the PEP is unreasonable or imprudent. To allow only partial recovery based on proportion of benefit only assures a much greater possibility that the income generated by the Company will not yield the return it is authorized to earn.

Q. Are Staff and RUCO's adjustments consistent with prior Commission orders?

A. Yes and no. The Commission's position on the recovery of incentive compensation program cost has varied, somewhat inconsistently, based on the nature of the incentive compensation. UNS Gas' incentive compensation is a cash-based incentive program available to all non-union employees. The Commission allowed full recovery of a similar program for Arizona Public Service Company ("APS") in Decision No. 69663 (June 28, 2007). However, I acknowledge that the Commission previously allowed only 50% recovery of the PEP in the last UNS Gas and UNS Electric rate cases, relying primarily on how it treated the Southwest Gas Management Incentive Program in the Southwest Gas rate cases. UNS Gas continues to believe that given the nature of its PEP, it should be allowed full recovery of the PEP expense.

Q. Does the Commission's position in the recent APS rate case support your position?

A. Yes. The Commission provided for full recovery of APS' Cash-based Incentive Compensation plan expenses in Decision No. 69663 (page 37) stating:

> APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)

Q. Can you provide more detail as to why you disagree with Staff and RUCO?

A. Certainly. The evidence I discuss below shows that UNS Gas' total employee compensation including the PEP program is reasonable and to deny recovery is to ensure that UNS Gas will not have a reasonable opportunity to recover its operating cost. Again, neither Staff nor RUCO assert that the total employee compensation including PEP is unreasonable. In effect, UNS Gas is being penalized simply for its compensation structure.

I believe the PEP program costs are actually a net savings to customers. I also believe the program provides a valuable management tool to promote increased earnings, to promote additional cost savings, to motivate individual employees, to encourage groups of employees to work together to impact specific goals, and to aid in the retention of the higher-performing employees. All of these are ultimately benefits passed on to customers.

The goals or targets of the current PEP program are also heavily weighted toward providing benefits to customers. The program uses operational cost containment, customer service goals and financial performance measures in setting the PEP level. The benefits of the current program goals and objectives merit full recovery of the expense as it provides benefits to the customers and doesn't provide for unreasonable salary and wage expense.

No party disputes that the PEP program actually reduces the ultimate cost passed on to customers in the form of reduced payroll and benefits cost. It is counter-intuitive to penalize the Company for having an employee compensation program that reduces the ultimate costs passed on to the customers, that promotes increased safety, increased customer service, the reduction of operating costs and increases the financial soundness of the Company and does not result in unreasonable or imprudent employee compensation levels.

Similar to the APS Plan, the PEP rewards certain performance if the desired results, which are based on objective criteria, are achieved. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture.

Q. Please further explain the PEP and some of the benefits to customers, the Company and to employees.

A. A more accurate description of that program would be "a portion of an individual's fair and reasonable compensation put "at risk" to encourage and enhance group and individual performance". The at-risk compensation portion is used on an individual basis to reward specific performance and provides management with an additional tool to encourage further cost savings, motivate individuals and to encourage employees to impact goals.

If the PEP program is eliminated, there would be considerable increased pressure on base compensation. Employee base compensation would eventually have to be increased toward market to allow the Company to compete in attracting and retaining a skilled workforce. It is not reasonable to assume that the Company would be able to continue to attract employees at compensation rates well below the market median, without the PEP. So, Staff's recommendation will drive base compensation upward so that little to no compensation is variable or at risk. If that result came to fruition, then UNS Gas employees would not be as incentivized to meet performance based criteria that directly benefit UNS Gas customers.

Q. Are there advantages to the PEP versus just paying base compensation?

A. From the Company's and the customers' perspectives, there are many advantages to using a program like PEP, rather than just paying median market wages as non-variable base

compensation. The most direct savings result because PEP is not part of base compensation; therefore employee costs such as vacation pay, sick pay, long term disability, 401K matching, pension expense and other post-retirement benefits that are based on base pay are all reduced. The impact of reduced compounding wage increases that would be based on a higher base pay total is another benefit. Additionally, the benefits produced from the specific goals are tied to a portion of the employees' compensation, which allows management to have greater flexibility to distinguish and reward high-performers, to attract and retain more talented employees, and to mitigate the costs of training new employees by retaining key ones. Neither Staff nor RUCO dispute these facts and that the PEP brings added flexibility at reasonable cost.

From the employee perspective, the proper mix of base wages and incentive pay has benefits. Individual employees are rewarded for contributing to the overall success of the organization and are allowed to directly participate in corporate success with a clear line of sight to goals. Employees can be acknowledged and rewarded for making a difference by exhibiting extra effort, working more hours on the job (for professionals not eligible for overtime pay), or supporting the program goals. Also, payment to individual non-union employees is discretionary, so talented and high-contributing employees can earn more through the program, which can be a motivating factor and can also lead to higher retention rates for more talented employees. Rather than being an over-inflated program, the PEP provides direct benefit to UNS Gas customers economically. Neither Staff, nor RUCO for that matter, have presented any evidence to demonstrate that the compensation and benefit packages of the UNS Gas employees (including incentive compensation) are not prudent or reasonable.

Q. Mr. Smith also refers to the Commission's treatment of Southwest Gas' Management Incentive Program to support its position. Is UNS Gas's PEP the same as Southwest Gas' Management Incentive Program ("MIP")?

A. No. Southwest Gas' MIP program appears limited to management personnel. UNS Electric's PEP is for all non-union employees. Further, Southwest Gas' MIP appears specifically related to return on equity targets and customer to employee ratios. The Company's PEP is based on broader and more wide-ranging factors, of which financial performance is only a part of the consideration.

Q. You mention the PEP is for all non-unions employees. Why are union employees not eligible for PEP compensation?

A. The union employees wage rates are collectively bargained and up to this time the union members have not been receptive to putting any portion of an individual's pay at-risk and/or allowing equivalent grade employees to earn differing pay levels based on performance.

2. <u>Stock Based Compensation.</u>

Q. Did either Staff or RUCO reduce the stock based compensation cost contained within the test year?

A. Yes. RUCO excluded 100% of the compensation expense contained in the test year related to differing types of stock compensation. Staff did not expressly address this issue.

Q. What is Mr. Smith's basis for this exclusion?

A. Mr. Smith cites the recent APS and UNS Electric rate case decisions in which the Commission denied recovery of stock based compensation. In the APS decision, the Commission expressed a concern that the program could promote inappropriate short-term

management decision making. However, I believe the exact opposite is true. Stock-based compensation or equity compensation is primarily awarded in the form of stock options, which vest over a period of years and whose ultimate value is based on the *future* strength and performance of the Company. As such, the stock based compensation strongly promotes long-term employee and director retention and long-term sustainable performance activities.

Q. Why do you believe full recovery of the stock based compensation is appropriate in this case?

A. 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 program, like PEP, is designed to put individual employee's compensation at risk. However, this program focuses on creating incentives for long term planning and the long term success of the Company. Clearly customers benefit from the long term planning and success of the Company. Indeed, the Commission itself recognizes the benefits of long term planning through its Integrated Resource Planning, Energy Efficiency Standards, Renewable Energy Standards and Renewable Transmission planning dockets – all are focused on the long term service provided to customers.

3. <u>Supplemental Executive Retirement Plan ("SERP").</u>

Q. Did Staff or RUCO take exception to the SERP expense contained within the test year?

A. Yes. Both parties removed 100% of the SERP expense allocated to UNS Gas, asserting that SERP expense is simply an excess benefit provided to select executives. The Company strongly opposes this representation as misleading and incorrect. This expense

and program is not an "excess" benefit or cost. It is the cost required to keep retirement benefits equal as a percentage of compensation for eligible employees.

Q. Do you agree with their adjustments to remove 100% of the SERP expenses allocated to UNSG?

A. No, I do not. They both have relied upon recent Commission decisions that disallowed the recovery of SERP expenses. The SERP program is a portion of the compensation and benefits package made available to UniSource officers. The level of compensation, incentives and benefits are all determined by the Compensation Committee of the Board that is comprised of independent Board members.

The reason a program like SERP is necessary is because of funding deductibility limits defined within the Internal Revenue Code. And those funding limits are set based on tax revenue collection needs, not on the point at which it is no longer fair to provide retirement benefits. They are not a guideline for how much is fair and reasonable as part of an employee benefit program. The evaluation of that should be the reasonableness of the compensation and the executive benefit package itself. All UNS Gas is asking for here is to allow executives to have the same proportion or level of retirement benefits as for other Company employees

Q. Is SERP an excess benefit?

A. No. It simply keeps those individuals whose compensation level exceeds deductibility levels equal to those individuals whose compensation does not. The intention of the plan is to keep them equal.

Q. Do you have any additional comments on Staff's SERP adjustment?

A. Yes. Staff incorrectly pulled an amount from the lead lag study as the SERP expense and the amount they used is actually the test year PEP expense for UNS Gas.

C. Rate Case Expense.

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Dr. Fish (at page 29) proposes an adjustment to Rate Case Expense based on the Company's response to Staff Data Request 6.88. UNS Gas agrees with that adjustment and Exhibit DJD-1 reflects that change in the Company's Rate Case Expense pro forma adjustment.

RUCO reduced the Company's proposed rate case expense. Mr. Smith (at page 50-51) proposes an allowance of a normalized level of $100,000 on an annual basis in expense for rate case expense based on the $300,000 rate case expense recovery over three years provided in the last UNS Gas rate case.

Q Do you agree with RUCO's recommendation of a normalized annual allowance of $100,000?

A. No. To the date of this testimony UNS Gas has already incurred over $400,000 in external rate case cost through the use of substantial TEP employee time (which is allocated to UNS Gas) and outside counsel. The final cost will be in excess of UNS Gas' initial $500,000 estimate. These costs are the incremental real cost associated with filing a rate case by a utility that does not have its own regulatory counsel or rates group on hand and built into base rates.

Q. Do you have any other comments on this issue?

A. Yes. RUCO is recommending an annual allowance of $100,000 for rate case expense. Putting that amount in some context, it would not even cover the cost of UNS Gas (with almost 150,000 customers) employing one attorney on staff full time as regulatory counsel considering salary, benefits and overhead. It is just not a reasonable level of recovery. Also, if RUCO wants to establish a normalized level of rate case expense, it should be based on actual cost and the expected level to be incurred. RUCO's position, if adopted, would penalize UNS Gas for efficiently outsourcing its regulatory needs by disallowing prudently incurred costs. UNS Gas contends that its use of TEP employees and outside counsel is more cost effective than hiring more employees to staff an entirely separate regulatory division at UNS Gas. RUCO's position would have the effect of encouraging the Company to reevaluate this cost effective system in favor of more costly, but necessary, options, including the hiring of regulatory counsel and staffing a regulatory division.

Q. Are there other problems with RUCO's reduction?

A. Yes. If Staff's and RUCO's recommendations and the returns they will generate are adopted by the Commission, it is very likely that UNS Gas will need to quickly file another rate case. There is no basis for RUCO to assume a three year amortization period under such a scenario. Based upon the most recent evidence in which UNS Gas has filed serial rate cases, RUCO should be recommending an 18 month amortization period. If their $300,000 artificial limit is approved, then the annualized or normalized annual expense would be $200,000 to reflect the short period the rates in this case are likely to be in effect, and to give the Company a reasonable opportunity to recover some portion of its allowed rate case expense.

D. Membership Dues Expense - American Gas Association ("AGA").

Q. Did Staff or RUCO reduce the Company's pro forma membership dues expense?

A. Yes. Both Staff and RUCO proposed adjustments to AGA dues expense.

Q. Does the Company agree with their proposals?

A. No. First, Staff is recommending the same reduction (3.5%) of the AGA dues as the last rate case. However, UNS Gas already agreed to follow the approach from the last rate case, and therefore UNS reduced the AGA dues expense by 4.0% in its Application. Staff's adjustment is unnecessary and essentially double-counts the reduction.

Second, RUCO is recommending the normal and recurring core dues associated with the AGA be reduced well beyond the portion identified as lobbying expense by the AGA. This reduction is based on a 2001 NARUC study that is based on 1999 data. Not only is this analysis stale, but it is not relevant. The Company has provided substantial and compelling support of and for the many benefits provided by the membership and the expense sought for recovery is reasonable and should be recoverable.

E. Call Center Expense.

Q. Did either Staff or RUCO reduce the Company's Call Center expense?

A. Yes. Staff reduced the Call Center expense being allocated to UNS Gas from TEP. TEP's Call Center serves UNS Gas, UNS Electric and TEP. Dr. Fish asserts that the increase in the expense level being allocated to UNS Gas is not commensurate with an increased service level and therefore is inappropriate. Dr. Fish adjusted test year expense back to the level approved in the last rate case, which is based on a 2005 test year.

Q. What was the basis for Dr. Fish's assertion?

A. Dr. Fish argues that while the costs increased, the number of "service orders" did not substantially increase from 2005 to the test year.

Q. Do you agree with Dr. Fish's adjustment to reduce the test year expense for the Call Center?

A. No. Service orders are a poor measurement of Call Center use; in fact UNS Gas customers have substantially increased use of the Call Center. Moreover, assuming expense levels established using a 2005 test year are appropriate for rates going in to effect in 2010 without any adjustment for inflation, wage increases or equipment additions is unreasonable. The Call Center has seen the magnitude of call volume and call duration for UNS Gas grow by approximately 150% over the 2005 levels. Service orders are only a minor portion of the services provided by the Call Center to UNS Gas. UNS Gas is using more of the Call Center's capacity (as one of the three affiliates) then it was in 2005. In addition, the overall annual operating cost of the Call Center has increased 22% from 2005 to 2008. The overall capital investment in the facility, computers, and phones will continue to increase as the company ensures that customers have a mechanism to access the Company.

Q. You state that UNS Gas customer usage of the Call Center has increased. What data do you have to support this assertion?

A. From the last test year (2005) through 2008, call volume has increased steadily. In 2005, the Call Center received 352,330 calls for UNS Gas; in 2006, the Call Center received 483,026 calls; in 2007, the Call Center received 514,689 calls; and in 2008, the Call Center received 526,156 calls. This amounts to an increase of 150% from 2005 to 2008. In 2006, the Call Center spent approximately 16.5% of its time handling UNS Gas calls, while in the first half of 2009 that number had increased to almost 22%.

Q. If present service levels were handled independently by UNS Gas, would the cost be higher?

A. Absolutely. UNS Gas as an independent company would need a facility, phone lines, computer systems, phone systems, Call Center employees, supervisors, a manager and so forth. By joining with its affiliates TEP and UNS Electric, UNS Gas realizes economies of scale that it could not achieve as a stand-alone customer. It is more cost effective to share the significant fixed cost with two other utilities. UNS Gas should not be denied full recovery of the reasonable cost to serve the demands of its customers. Adoption of Staff's recommendation would encourage the Company to reevaluate this cost effective system against implementing a standalone Call Center for UNS Gas.

Q. Why invest in the Call Center?

A. The Call Center is the primary vehicle in which customers have human contact with the Company. The Company values our customers, and wants to ensure that customers have a way to get answers to questions they may have regarding their service. As a result, we continue to invest in the Call Center. In 2007, a new billing system was implemented. In 2009, we are making other technology improvements to ensure that customers obtain the information they desire. While the 2009 expenses are not included in this rate case, these investments can fortunately be shared by three affiliates serving over 600,000 customers as opposed to UNS Gas having to make these investments on its own. Furthermore, upon acquiring the gas assets from Citizen's in 2003, the access customers had in calling the Call Center was inadequate, as evidenced by many customers not even able to get into the system, let alone talk to a customer service representative. We will continue to invest in a reasonable level of technology in our Call Center to give our customers a reasonable customer service experience.

Q. How are Call Center costs allocated today?

A. Call Center costs are allocated based on the talk time that the Call Center experiences by customers of TEP, UNS Electric, and UNS Gas. However, in three districts (Kingman, Havasu, and Nogales) there is combined talk time for both UNSE and UNSG, and, as a result, the system cannot distinguish between talk time for a particular company, so in these three districts talk time is split by customer count.

Q. Why is Dr. Fish's adjustment incorrect?

A. Dr. Fish bases his adjustment on the declining service orders per month. As I noted above, service orders are only one small contributor to talk time. If customers only called for a hook up for new service, we would have a significantly smaller Call Center. Furthermore, in spite of declining service orders per month, inbound call volume, and the costs associated with that call volume, has continued to increase. Often, we have to explain the bills, make billing arrangements, discuss credit terms, discuss a disconnect or reconnect due to a past due bill, etc. Answering our customers' questions and providing them the information they desire takes time, and time on the telephone is an appropriate and more rationally related way to allocate costs than an allocation based solely on one aspect of customer service, the service order.

The specific talk time for UNS Gas customers has increased over time: in 2006, the average talk time was 16.6% of the total for the three affiliates; in 2007, 23.6%; in 2008, 20.4%.

Q. What other factors contributed to the increase?

A. The other contributing factor is that costs have increased in the Call Center over time. On average in 2005, total monthly Call Center costs before allocations were roughly $415,000. In the test year, July 2007 to June 2008, the monthly costs averaged about

$507,000, a 22% increase over more than three years. In that time, wages and on-going costs continue to increase, and we continue to offer new services to our customers that are included in these costs. For example, UNS Gas customers now have credit card processing and on-line bill presentment. These new services cost money that increase our costs but ultimately provide the customer with better options and a better service level experience. However, increasing talk time at UNS Gas, was the largest contributor to the allocated Call Center costs, not increased Call Center costs.

F. <u>Bad Debt Expense.</u>

Q. Did Staff or RUCO reduce the Company's pro forma bad debt expense?

A. Yes. Staff reduced the pro forma expense level based on Dr. Fish's assertion that the Company has recorded too much expense for bad debt the last three years based on his assertion that the Company is over reserved for bad debt.

Q. Do you agree with Dr. Fish's assertion that the Company is over reserved and his corresponding assertion that bad debt expense has been overstated?

A. No. Dr. Fish has performed some analysis of the change in the Allowance for Bad Debt ("allowance") account that has taken place from the years 2005 and 2006 in comparison to the current levels and asserts that it is over stated by approximately 100%. The allowance account is a contra asset account that reduces the Accounts Receivable ("A/R") account on the Company's balance sheet so that the net of the two reflects the reality that not all of those accounts will be fully collected. This account is reconciled on a quarterly basis by the accounting department of TEP and is audited annually by an independent accounting firm to insure that it is materially accurate. To say that it is overstated by that magnitude is to assert error on the part of the accounting professionals. This is something to which I take considerable exception and that is blatantly incorrect.

Q. Can you tell us how the Company evaluates the allowance account?

A. Yes. Primarily this is achieved by looking at the aged accounts receivable reports and the historical recovery levels of these aged assets. A hypothetical example would be that you have $10 million of A/R and $1 million of that is over 120 days unpaid – historically the Company only collects 10% of accounts that delinquent. In that example, you would have an allowance account balance of $900,000 until you actually wrote the accounts off and removed them from A/R. What Dr. Fish did not discover in his analysis was that the allowance account grew substantially in 2007 because of the conversion of the Customer Billing System. Upon this conversion the normal process and timing of A/R write offs was essentially put on hold.

Q. What was the impact of putting the normal A/R write off process on hold?

A. When you do that the A/R balance becomes overstated, you have not cleared accounts out that are just not collectible any more. Correspondingly, the allowance account grows so as to reflect the proper "net" A/R balance. This holding on write-off processing also impacted the historical net write-off information. So if you look at net write-offs historically there was also a significant decrease in 2007 and that information would skew any normalization if you used an average of net write-offs including that period.

Q. So what does this mean in relation to Dr. Fish's adjustment to bad debt expense?

A. It means that Dr. Fish was looking at only one side of the equation and came to an incorrect conclusion. Bad debt expense is the accrual based expense to match expected net write-offs with revenue as it is recorded. Now this is not a perfect process, it is done by continually looking at your historical levels of recovery and looking at the allowance account versus the aging of your A/R and monitoring other items like large customer bankruptcies. That is why for ratemaking purposes the preferred method is to take net write offs (or bad debt expense) as a percentage of retail revenue over a long period of time

and use that normalized relationship to apply to pro forma retail revenue to calculate pro forma bad debt expense. That is why the Company's calculation of 4.87% of pro forma retail revenues is a proper reflection of expected bad debt levels based on the historical levels of bad debt expense and net write-off levels. The allowance account is at an appropriate level balance given the accounts in A/R and the company as expensed the proper level for the three year period in question. As such, the Company's adjustment should be accepted.

G. <u>Outside Legal Expense.</u>

Q. Did either Staff or RUCO reduce the Company's pro forma outside legal expense?

A. Yes. Both Staff and RUCO reduced UNS Gas's pro forma outside legal expense. Staff chose to eliminate the Company's adjustment entirely and did not give any substantive reason for the elimination. RUCO reduced the adjustment by about two-thirds with the primary reason being that the Company's normalization included cost associated with the Company's intervention, in support of its customers, in El Paso Natural Gas Company ("EPNG") rate case before FERC. Both Staff and RUCO fail to provide an allowance for normalized, on-going costs of legal services, based on either historical or projected costs.

Q. Do you agree with RUCO's significant reduction of the Company's normalized outside legal cost?

A. No. The basis for Mr. Smith's adjustment is to exclude the cost to monitor and participate in the EPNG rate case that was incurred in the years 2005-2007 in calculating his normalized outside legal cost. UNS Gas has been involved in monitoring all, and participating in many, of the interstate pipeline filings made by EPNG and Transwestern Pipeline ("TW") at FERC each and every year since UES has owned the Company. Since July 2007, there have been approximately thirty filings, in addition to general system-wide

rate case filings, made by EPNG and TW at FERC. UNS Gas has intervened in and monitored these filings, and has participated in and litigated some of these cases because the filings could result in changes to the EPNG and TW pipeline tariffs, which in turn could affect the rates and terms and conditions under which UNS Gas receives services from those pipelines and ultimately affect the services and rates of UNS Gas' core customers. UNS Gas has no indication that this level of intervention on behalf of the customers of UNS Gas will be reduced. EPNG filed a Natural Gas System Wide Rate Case on June 27, 2008 (Docket No. RP08-426-000). This rate case is currently progressing toward litigation and is not likely to be resolved until first quarter 2010. If EPNG is not satisfied with the rate case order handed down by FERC, they could appeal it to the Court of Appeals. Additionally, TW will most likely file for a system-wide rate case in 2011. Both EPNG and TW file rate cases regularly and frequently; there is no basis to assume that UNS Gas will not incur legal costs in these cases, unless RUCO and Staff are suggesting that UNS Gas simply stop participating in FERC cases thereby ensuring that UNS Gas customers' interests will not be represented in those matters.

In the last UNS Gas rate case, , the Commission allowed the Company to recover outside legal expenses related to FERC rate cases (Decision No. 70011 at page 20). It should do so here, as well. If the Commission now eliminates the historical level of cost recovery of intervention in these cases from base rates – the unequivocal message to UNS Gas is that UNS Gas customers' interests should not be represented in FERC cases in the future.

H. <u>Fleet Fuel Expense.</u>

Q. Did Staff or RUCO reduce the Company's pro forma fleet fuel expense?

A. Yes. Both Staff and RUCO proposed to reduce the Company's pro forma expense to reflect the reduced cost of fuel currently being incurred by the Company.

Q. Do you agree with either Staff or RUCO's proposed adjustments to reduce fleet fuel expense?

A. No. I can agree that the test year level of expense may need to be adjusted given the extreme volatility of fuel expense, but I do not agree with the adjustments proposed by either.

Q. Please explain your concerns with Staff's proposed adjustment.

A. Staff has applied a forward looking estimate of the average cost of fuel per gallon from the Energy Information Administration ("EIA") of $1.96 per gallon. As of the time this testimony was prepared the average cost of gasoline published by the EIA for the West Coast (excluding California) was $2.82 per gallon. So clearly the price estimate in Dr. Fish's adjustment is not reflective of current known price levels.

Q. Please explain your concerns with RUCO's proposed adjustment.

A. Mr. Smith applied a couple techniques to normalize fuel expense. He used the last three years fuel consumption levels to calculate an average level of fuel purchased and then applied an estimated fuel cost of $2.28 per gallon derived from www.arizonagasprices.com. Although the Company does not concede that the Commission should grant any evidentiary weight to a website that chronicles fuel prices throughout the State of Arizona, especially where the Company has presented evidence of fuel costs it incurred in its particular service territory, as of the time this testimony was prepared the average cost of gasoline as published by www.arizonagasprices.com was $2.58 per gallon. Based upon Mr. Smith's reliance on this website, at a minimum, his adjustment must be increased significantly. This significant change in price in such a short period of time is further evidence of why the Commission should not afford any weight to a website that simply chronicles daily fuel prices. This method produces volatile and

misleading data regarding fuel expense, especially when compared to UNS Gas' proposal, which averages fuel costs actually incurred in its service territory over a period of years.

Q. Are there other issues with Staff and RUCO's adjustments?

A. Yes. RUCO inadvertently had an additional amount in their schedules and actually reduced fuel cost by $471,000 in its revenue requirements. The amount they intended to reduce it by was $241,000. Also both Staff and RUCO relied upon data provided by the Company and labeled as fuel expense, but it was actually fuel cost. Fuel cost exceeds fuel expense because a portion of fuel cost is capitalized. The fuel cost data used by Staff and RUCO does not provide an accurate measure of fuel expense. The amounts spent to obtain fuel for UNS Gas, and the a per gallon data is correct, but the actual expense is only 73.4% of that cost, the other 26.6% of that cost went to capital projects. Fuel cost as identified goes into a transportation clearing account and then is charged out as vehicles are used along with other cost like insurance, and maintenance. 26.6% of those costs actually go to capital projects and thus the fuel expense is only 73.4%.

Q. What does the 73.4% mean to Staff and RUCO's adjustments?

A. It means that only 73.4% of Staff's and RUCO's reductions should actually be applied to revenue requirements if either were to be accepted.

Q. What is the Company's suggestion for adjusting test year fuel expense?

A. Fuel prices are highly volatile. The Company recommends using the three year average to normalize the cost based on recent actual cost incurred by UNS Gas. UNS Gas' primary service territories are not located in Arizona's major urban communities and as such UNS Gas' actual fuel cost tends to be higher than Tucson and Phoenix. The average price per gallon of fuel incurred by UNS Gas over the past three years in its service territory is $3.05 per gallon. This amount is known, measurable and provides compelling evidence of UNS

Gas' fuel expense, especially when compared to statewide internet cost projections or National or even Regional statistics regarding fuel prices as presented by Staff and RUCO. By applying the three year average cost to the three year average consumption the Company is suggesting a $51,258 reduction in test year fuel cost. If this three year average is not used, then the actual test year expenses should be used as reflected in UNS Gas' original Application. In no event should Staff's and RUCO's internet cost projections be used, as they are simply not known and measurable.

I. <u>Postage expense.</u>

Q. Do you agree with the postage expense adjustment proposed by Staff?

A. Yes. Staff proposes an adjustment based on the known and measurable increase in postage rates that has occurred. However, this adjustment would then need to be corrected to reflect the correct annualized number of customers, as discussed in Mr. Erdwurm's testimony.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT

DJD-1

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	RUCO As Filed 6/8/09	UNSG Revised 7/8/09	Summary	UNSG Witness
Original Cost Rate Base - Unadjusted	$176,153,570	$176,153,570	$176,153,570	$176,153,570		Dukes
Rate Base Adjustments						
Acquisition Adjustment	32,852,425	32,852,425	32,852,425	32,852,425	No change	Dukes
Southern Union Acquisition Adjustment	(16,145,381)	(16,145,381)	(16,145,381)	(16,145,381)	No change	Dukes
Griffith Plant	(4,942,600)	(4,942,600)	(4,942,600)	(4,942,600)	No change	Dukes
Build-Out Plant	(7,896,628)	(7,896,628)	(7,896,628)	(7,896,628)	No change	Dukes
Golden Valley Plant	(4,393,096)	(4,393,096)	(4,393,096)	(4,393,096)	No change	Dukes
Post-Test Year Non-Revenue Plant in Service	1,527,588	-	-	1,527,588	Staff disallowed CWIP-Post Test Year Plant (THF-B-5, pg 14-16). RUCO disallowed CWIP-Post Test Year Plant (B-1, pg 13-18).	Dukes
Customer Advances Adjustment	589,152	-	-	589,152	Staff disallowed Customer Advances (THF-B6, pg 16-17). RUCO disallowed Customer Advances (B-2, pg 18-20).	Dukes
Accumulated Deferred Income Taxes	4,450,108	4,411,114	4,253,852	4,450,108	Changes are recalculations based on proposed pro forma adjustments. Staff disallowed SERP expense (THF-B9, pg 18-19). RUCO disallowed specific items (Div Equivalents, Restricted Stock, Stock Options, Vacation & Pension) from the ADIT Calculation (B-6, pg 23-24).	Kissinger
Working Capital	97,967	(1,530,037)	2,296	2,183,948	Staff adjusted cash working capital for a change in the purchased gas payment lag and for the impact of the other proposed adjustments to operating revenue and expense (THF-B7, B8 & B10, pg 17-18). RUCO disallowed the 13-month average adjustment of $92,671 for Prepaids (B-3, pg 20-21). UNSG adjusted cash working capital as a result of other pro forma adjustments/changes and to reflect the corrected purchased gas payment lag.	Dukes
Total Adjustments	6,139,535	2,355,797	3,730,868	8,225,516		
Pro Forma OCRB	182,293,105	178,509,367	179,884,439	184,379,086		
Proposed Rate of Return	8.75%	8.24%	7.55%	8.75%	Staff ROE 10%; RUCO ROE 8.61%, Company ROE 11%	Grant
Required Operating Income	$15,950,647	$14,709,172	$13,581,275	$16,133,170		

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	RUCO As Filed 6/8/09	UNSG Revised 7/8/09	Summary	UNSG Witness
Original Operating Income - Unadjusted	$13,447,491	$13,447,491	$13,447,491	$13,447,491		Dukes
Operating Income Adjustments						
Operating Revenue Adjustments						
Griffith Plant Operations	(865,152)	(865,152)	(865,152)	(865,152)	No change	Dukes
Golden Valley Rev & Exp	(2,148,778)	(2,148,778)	(2,148,778)	(2,148,778)	No change	Dukes
Gas Cost Rev & Purchased Gas Cost	(90,472,202)	(90,472,202)	(90,472,202)	(90,472,202)	No change	Dukes
NSP Revenue & Gas Cost	(17,165,706)	(17,165,706)	(17,165,706)	(17,165,706)	No change	Dukes
Rate Case Revenue Annualization	1,448,476	1,797,514	1,448,476	1,448,476	Staff's adjustment differs because they assumed additional customers for the entire year based on 12/31/2007 customer levels increased by 1.25%.	Erdwurm
Customer Annualization	(516,003)	655,768	-	(516,003)	Staff adjusted revenue reflect additional customers based on 12/31/2007 customer levels increased by 1.25%. RUCO argues we are a growing system and that a negative annualization made no sense so they reversed our adjustment.	Erdwurm
Weather Normalization	(882,453)	(903,889)	(882,453)	(882,453)	Staff's adjustment reflects the additional assumed customers.	Erdwurm
DSM Revenue & Expense	(130,917)	(130,917)	(130,917)	(130,917)	No change	Dukes
Service Fees & Late Fees	239,235	239,235	239,235	239,235	No change	Dukes
Total Adjustments to Operating Revenues	(110,493,500)	(108,994,127)	(109,977,497)	(110,493,500)		
Operating Expense Adjustments						
Griffith Plant Operations	(160,390)	(160,390)	(160,390)	(160,390)	No change	Dukes
Golden Valley Rev & Exp	(1,763,947)	(1,763,947)	(1,763,947)	(1,763,947)	No change	Dukes
Gas Cost Rev & Purchased Gas Cost	(90,472,202)	(90,472,202)	(90,472,202)	(90,472,202)	No change	Dukes
NSP Revenue & Gas Cost	(16,696,668)	(16,696,668)	(16,696,668)	(16,696,668)	No change	Dukes
DSM Revenue & Expense	(130,917)	(130,917)	(130,917)	(130,917)	No change	Dukes
Payroll Expense	362,018	362,018	136,278	362,018	RUCO removed the 2010 pay increase, stating it is not known & measurable, but allows the 2009 increase (C-12, pg 55-56)	Dukes
Payroll Tax Expense	2,557	(9,182)	(22,325)	2,557	Staff adjusted payroll tax expense to reflect the proposed reduction for incentive compensation expense but used an overall rate of 10%, which is incorrect (THF-C16, pg 28). RUCO is removing the Payroll Tax associated with the 2010 pay increase disallowed. RUCO did not excluded the Capital portion in their Payroll Tax calculation. Should have been incrementally adjusted by $17,354 instead of $24,882. (C-12, pg 55-56)	Dukes
Pension and Benefits	77,544	77,544	77,544	77,544	No change	Dukes
Incentive Compensation (Staff & RUCO Adj)	30,930	(86,463)	(121,581)	30,930	Staff adjusted based on allowance of 50%, but appears to have incorrect expense amounts (THF-C14, pg 27-28). RUCO disallowed 50% of the Incentive Comp in the TY (TY total is $280,968/2 = $140,484 disallowed & $24,054/2 = 12,027 disallowed for taxes), RUCO's adjustment was not done incremental and is including the as filed adjustment as well (C-3, pg 29-35).	Dukes

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	RUCO As Filed 6/8/09	UNSG Revised 7/8/09	Summary	UNSG Witness
Rate Case Expense (Staff & RUCO Adj; UNSG Adj.)	200,000	141,667	41,667	141,667	Staff adjusted test year rate case expense to reflect the correction of the error in the original pro forma as provided in response to Staff Data Request TF 6.68 (THF-C17, pg 29). RUCO allows only $300,000/3 for $100,000 per year and is removing the $58,333 prior year rate case expense still included in the TY. ($100,000 allowable - $58,333 included in test year = $41,667 adjustment) (C-9, pg 50-53). UNSG is adjusting expense in accordance with the corrected pro forma as presented in response to Staff Data Request TF 6.68.	Dukes
CARES Expense	(25,983)	(25,983)	(25,983)	(25,983)	No change	Dukes
CARES Regulatory Asset Amort.	164,197	164,197	164,197	164,197	No change	Dukes
Y2K Amortization	(76,753)	(76,753)	(76,753)	(76,753)	No change	Dukes
Miscellaneous Expenses (Staff Adj for AGA dues & postage expense; RUCO Adj for AGA dues)	(827,301)	(779,380)	(844,063)	(827,301)	Staff adjusted postage expense for the postage increase of $.02 effective in 5/11/09 using Staff's annualized customers in THF-C4 and the incremental postage cost based on the $.02 increase and UNSG actual customers per Schedule H2 (THF-C8, pg 25), but the final adjustment was incorrect do to an addition error. Staff adjusted AGA dues expense to reflect the same disallowance in the prior rate case (THF-C10, pg 25), but the AGA dues and the percentage disallowed are incorrect and UNSG already removed 4% of AGA dues in the original pro forma. RUCO disallowed 40% of the AGA dues in TY (C-6, pg 43-48).	Dukes
Normalize Outside Legal Expense	305,984	-	88,310	305,984	Staff disallowed the UNSG adjustment to normalize test year legal expense (THF-C11, pg 26) arguing that the adjustment was related to prior rate case expense, when the pro forma was to normalize the test year ignorring the large write-off related to prior rate case expense. RUCO disallowed a majority of El Paso legal costs in the normalization calculation (C-7, pg 48-49).	Dukes
Bad Debt Expense	63,211	(123,416)	63,211	63,211	Staff adjusted Bad Debt Expense (THF-C7, pg 23-24) to reflect the uncollectible rate used in the prior rate case, arguing that UNSG over-accrued the Allowance for Doubtful Accounts in the last three years and thus our three-year average overstates test year expense.	Dukes
Depr & Property Tax - CWIP-Post Test Year (RUCO Adj)	-	-	(95,042)	-	Staff did not adjust depreciation expense for the CWIP removed from rate base. RUCO adjuted Depr. & Property taxes for remove of the *CWIP-Post TY for rate base above* (C-2, pg 28-29).	Dukes
Stock-Based Compensation Exp (RUCO Adj)	-	-	(266,399)	-	RUCO disallowed 100% of the Stock Base Comp Expense in TY (C-4, pg 35-39).	Dukes
SERP (Staff & RUCO Adj)	-	(310,412)	(101,021)	-	Staff disallowed 100% of SERP expense (THF-C15, pg 28) but used the incorrect amount of SERP expense. RUCO disallowed 100% of SERP expense (C-5, pg 40-43).	Dukes
Fleet Fuel Expense (Staff & RUCO Adj; UNSG Adj.)	-	(294,599)	(471,826)	(51,258)	Staff adjusts Fleet Fuel Expense (THF-C8, pg 24) to reflect an average price per gallon of $1.96 for 2009. Staff's adjustment has an error in the result of the fuel cost of $1.96 per gallon multiplied by the total gallons used; the total Staff cost of $450,747 should be $437,027. In addition, Staff does not reflect the transportation allocation capitalization rate of 26.6% to Capital and 73.4% to O&M. RUCO normalizes Fleet Fuel Expense (C-8, pg 49-50). There is an error is RUCO's number: 1) the $471,826 includes $230,913 too much because the property tax adjustment is picked up twice; and 2) an adjustment needs to be made for the amount of fleet fuel that would be capitalized through the transportation allocation - 26.6% goes to Capital and 73.4% stays in O&M. UNSG is adjusting operating expense to reflect a 3-yr average fuel expense.	Dukes
Call Center (Staff Adj)	-	(484,798)	-	-	Staff is allowing allocation of call center cost based on our prior rate filing amount because request for service agreements have not increased substantially (THF-C12, pg 26-27).	Smith, Dukes

UNS GAS, INC.

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2008

	UNSG	ACC	RUCO	UNSG		
	As Filed	*As Filed*	*As Filed*	*Revised*		UNSG
	11/7/08	6/8/09	6/8/09	7/8/09	Summary	Witness
Synchronized Interest (Staff Adj)	-	54,906	-	-	Staff adjusted synchronized interest related to interest on debt as a separate expense instead of including it in the income tax adjustment.	Dukes
Depr. & Amort. Exp. Annualization	(227,976)	(227,976)	(227,976)	(227,976)	No change	Kissinger
Property Tax	1,354,074	1,354,074	1,123,161	1,354,074	RUCO adjusted the Property tax rate from 8.1359 to 7.6127 to reflect a different assesment rate period (C-11, pg 54-55).	Kissinger
Income Taxes	(824,391)	397,788	161,937	(808,257)	Changes are recalculations based on other pro forma adjustments.	Kissinger
Total Adjustments to Operating Expense	(108,646,013)	(109,090,892)	(109,620,788)	(108,739,470)		
Total Net Adjustments	(1,847,487)	96,765	(356,709)	(1,754,030)		
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		Grant
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		Kissinger
Increase in Gross Revenue Requirement	$9,480,876	$3,395,423	$841,000	$9,480,876		

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rejoinder Testimony of

Dallas J. Dukes

on Behalf of

UNS Gas, Inc.

August 5, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Dallas J. Dukes. My business address is One South Church Avenue, Tucson, Arizona.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc.

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

A. The purpose of my Rejoinder Testimony is to address certain adjustments that Staff Witness Dr. Thomas H. Fish ("Dr. Fish") discusses in his Surrebuttal Testimony. I also address several adjustments that Residential Utility Consumer Office ("RUCO") witness Mr. Ralph C. Smith ("Mr. Smith") discusses in his Surrebuttal Testimony.

Q. Did you file Direct and Rebuttal Testimony in this proceeding?

A. Yes

II. REJOINDER TO RATE BASE ADJUSTMENTS.

A. Post Test Year Non Revenue Plant in Service.

Q. Do Staff and RUCO still disagree with the Company's inclusion of Post Test Year Non Revenue Plant in Service within rate base?

A. Yes. Staff's witness, Dr. Fish, and RUCO's witness, Mr. Smith, continue their objection to including post test year plant in rate base.

Q. Has the basis for Dr. Fish's or Mr. Smith's removal of the Company's Post Test Year Non Revenue Plant in Service adjustment changed from that of their direct filings?

A. No. Dr. Fish and Mr. Smith continue to argue that post-test year plant should not be included in rate base with out conclusive proof that it is necessary to preserve the financial health of the utility and complete assurance it is revenue-neutral, expense-neutral, prudent, and necessary.

Q. With that list of criteria in mind, do you believe UNS Gas would ever be allowed to include Post Test Year Non Revenue Plant within rate base?

A. Given the requirement to meet each of the standards as defined by Staff and RUCO, it is unlikely that UNS Gas would ever qualify for inclusion of post test year plant. But the Commission has approved post test year plant in a number of cases.

Q. Do you agree with this standard?

A. No. UNS Gas does not believe the Commission's discretion and judgment to include post test year plant should be limited by Staff and RUCO's proposed standard. In Arizona we use historical test years to set rates and we see at least a three year lag from the end of the test year in one proceeding till new rates go into effect for the next proceeding. That is why UNS Gas believes the Commission should consider the inclusion of post test year non revenue producing plant in rate base as a reasonable adjustment. If Staff's and RUCO's recommendations are adopted, the Company believes it will be necessary to file another rate case in the near future.

Q. Has the Commission required such a showing in past cases?

A. No. Staff and RUCO have made similar arguments in the past – and they have been rejected. For example, in the Bella Vista water rate case, the utility requested inclusion of numerous system improvement projects into rate base as post test year plant. Staff and

RUCO argued that the plant should be excluded, because the plant "may improve system reliability resulting in lower expenses and increased revenues."[1] The Commission rejected this argument, noted that while plant constructed to serve existing customers could have some impact on revenues or expenses, the evidence did not show a **material impact** on revenues and expenses.[2]

Along similar lines, in an Arizona Water Company rate case the Commission explained that "inclusion of post test year plant always causes some mismatch between revenues and expenses, even if the post test year plant is revenue neutral."[3] The Commission nevertheless included the post test year plant in rate base. The Commission emphasized materiality again in a Rio Rico rate case, noting that "there would not be a material impact on revenue or expenses."[4]

Q. Will any impact on revenue and expenses be material?

A. No. The post test year plant we are requesting in rate base will not have a material impact on revenue or expenses.

Q. Did Staff or RUCO provide any evidence regarding increased revenue or decreased expenses?

A. Staff simply makes an unsubstantiated assumption that revenue or expenses will be impacted. Mr. Smith, for RUCO, points to UNS Gas's Response to RUCO data request 11.28.[5] UNS Gas stated that expenses "could" be reduced. The Response does not state that a reduction is likely, or that it would be material. Moreover, Mr. Smith fails to mention UNS Gas' response to RUCO 11.18.b, which notes that overall expense levels

[1] Decision No. 65380 (Nov. 1, 2002) at 9:15.
[2] Decision No. 65380 (Nov. 1, 2002) at 10.
[3] Decision No. 68176 (Sept. 30, 2004) at 5:12-13.
[4] Decision No. 67279 (Oct. 5, 2004) at 7.
[5] Smith Surrebuttal at 12.

have increased since the test year. Notably, neither Staff nor RUCO have testified that any impact to revenue or expenses would be material – as required by prior Commission decisions.

Q. What else do Staff and RUCO point to?

A. They argue that post test year plant should only be approved in "compelling"[6] or "very compelling"[7] circumstances. But the Commission has rejected such arguments before. For example, in Decision No. 65350, the Commission stated that "We do not agree with Staff and RUCO that the Commission has always required extraordinary circumstances to allow post test year plant."[8]

Q. What criteria has the Commission established?

A. The Commission summarized its past cases as follows: "In the past, the Commission has allowed the inclusion of post test year plant in circumstances where the new plant is revenue neutral and there is no evidence of a material mismatch between revenue and expenses and where the post test year plant is required for system reliability or to provide adequate service."[9]

Q. Does UNS Gas's requested post test year plant satisfy these criteria?

A. Yes. The post test year plant is plant that whose primary purpose is to serve existing customers and which would have been replaced regardless of customer growth.[10] As I have explained, there will not be a material impact on revenue or expenses.

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[6] Fish Surrebuttal at 2:19.
[7] Smith Surrebuttal at 17:9.
[8] Decision No. 65350 (Nov. 1, 2002) at 11:21-23.
[9] Decision No. 67279 (Oct. 5, 2004) at 6:7-10.
[10] See UNS Gas Response to RUCO 11.30.c (Attached to Smith Surrebuttal Testimony).

Q. What else does RUCO argue?

A. Mr. Smith argues that UNS Gas is not a water company, and past examples of post test year plant have been for water companies. True, but water company rates are set by the same principles and methods – matching, prudence, rate base, operating expenses, return on equity, etc. And many of the decisions involve large, sophisticated "Class A" water companies like Arizona-American, Arizona Water, and Chaparral City. All three of those companies are part of multi-state utility holding companies. Clearly, allowing post test year plant is not a policy limited to small, financially fragile water companies.

B. <u>Customer Advances.</u>

Q. Has the basis for Dr. Fish and Mr. Smith's removal of the Company's Customer Advances adjustment changed?

A. No. Their arguments continue to be that that Customer Advances are non-investor supplied capital and that is the required treatment based on the sample schedule B-1, Commission rule A.A.C R 14-2-103.

Q. Do you agree with Dr. Fish and Mr. Smith's position that customer advances are non-investor supplied capital?

A. Yes. That is why I have included all of the customer advances as of the end of the test year as **reduction** of rate base except for the small portion already expended by the end of the test year on projects not included within rate base. I am only asking that the Commission allow that small portion of cash advances not be deducted from rate base. Throughout the testimonies of Dr. Fish and Mr. Smith they speak of matching, but they fail to follow that principle for these advances. As I explained in my Rebuttal Testimony, Dr. Fish's and Mr. Smith's approach creates a mismatch between when plant-in-service is measured, and when the advances are measured. And this mismatch has the result of

eliminating from rate base pre-existing plant funded by investors. It's simply a mismatch to reduce rate base for these advances relating to plant that, as of the end of the test year, is not in service or in rate base. Staff's and RUCO's method amounts to reducing the return on and of investor-supplied capital.

Q. Do the Commission's rules forbid UNS Gas's request?

A. No. Staff and RUCO suggest that Rule 103 (A.A.C. R14-2-103) compels a ruling in their favor. In the past, Staff and RUCO have made similar arguments about post test year plant – that it is forbidden by Rule 103. The Commission has repeatedly rejected such arguments, finding that the Commission can approve adjustments to rate base notwithstanding Rule 103.[11]

Q. What about Mr. Smith's concern that UNS Gas does not reduce CWIP by Customers Advances prior to calculating AFUDC?

A. UNS Gas is not arguing for advances to be excluded as a reduction in rate base – UNS Gas is arguing for recovery of and on rate base properly invested in by the Company to serve customers. The projects funded by the advances UNS Gas is asking to exclude are not in rate base, not accruing AFUDC and historically over 80% of all advances are returned to the developers and never become contributions at all. The very minor amount of AFUDC that was accrued on the advance portion of these projects during their short construction period is only a fraction of the lost return on and of rate base being denied to UNS Gas.

[11] Decision No. 66849 (March 19, 2004) at 4:18-20; Decision No. 65350 (Nov. 1, 2002) at 10:10-12.

C. **Cash Working Capital.**

Q. Do the other parties still disagree with the Company's cash working capital calculation?

A. Yes. Dr. Fish argues that the payment terms agreed to by the Company with its largest natural gas supplier are not reasonable or representative of normal credit terms.

Q. Do you agree with Dr. Fish?

A. No. The necessity and prudency of the payment terms is being addressed by the Mr. Grant's Rejoinder Testimony.

Q. Did Mr. Smith address your revised Cash Working Capital adjustment in his Surrebuttal testimony?

A. Yes. Mr. Smith contends that the Company's proposed change to the purchased gas payment lag reaches outside of the test year and that we have not demonstrated that the change is permanent.

Q. Would you like to address Mr. Smith's contentions?

A. Yes. The altered payment terms began during the test year and my adjustment is essentially an annualization of that change – which is not really any different than annualizing for any other change that happens either to reduce or increase cost of service. The change happened during the test year, and then again the following winter. And according to those within the Company that manage the credit and payment terms, the change will be true again this winter. As far as being permanent – I am not sure that it is possible to deem any expense item or cost as permanent. But, by all reasonable standards it is recurring, known and measureable.

D. Reconstruction Cost New Depreciated ("RCND").

Q. Do you have any comments on the RCND study discussions by Staff in its Surrebuttal?

A. Yes. After re-evaluating our analysis, I need to revise my discussion on RCND. It appears that we did not properly alter the trend rate in our comparison of our present method with the study in the prior filing. If we alter the trend rate appropriately to be consistent with the prior study the RCND value in our present study would come down. Therefore, Dr. Fish is correct in his contention that the RCND value in this case is representatively higher in this filing versus the prior filing. If the Mains category were re-stated to reflect cast iron trend values the RCND would be $19.6 million less than the original filed amount.

Q. If the RCND value in your filing were adjusted to reflect the more conservative value would it impact the requested increase of UNS Gas?

A. No. As UNS Gas has limited its requested increase to $9.5 million, although we could support a greater request.

III. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Payroll and Payroll Tax Expense.

Q. Did RUCO continue its objection to the Company's payroll adjustments in its Surrebuttal filing?

A. Yes. Mr. Smith argues that there are compelling circumstances in the context of the current UNSG rate case, including the poor economic climate that warrant differing treatment then Southwest Gas, UNS Electric and TEP were afforded in their last rate cases.

He also offers some information on a few utilities in other states that have forgone or limited non-bargaining employee wage rate increases.

Q. Would you like to comment on Mr. Smith's assertion that perhaps UNS Gas should not be allowed recent Commission treatment for pay rate increases because of the present economic conditions?

A. Yes, I would. UNS Gas understands that this is a difficult time. We are sympathetic to our customers. That is why we have proposed limiting our rate increase to $9.5 million when we could justify a larger increase. And that is why we proposed exempting our low income customers from the base rate increase.

We took these actions due to the concern for low income customers. Such explicit measures are preferable to artificially pretending that certain necessary costs will not occur. The employee levels as of the end of the test year are known, as are the wage increases.

Further, the present process usually benefits the customers in that rates are set based on historical information and payroll costs generally increase. For example, the present rates in effect were set based on a calendar year 2005 adjusted for a 2006 pay rate increase. The customers have benefited from not having wage increases reflected in rates attributable to the increased payroll cost paid by the Company in 2007, 2008 or 2009.

Q. What about Mr. Smith's contention that some other utilities are forgoing at least some portion of wage increases in rate filings in other jurisdictions?

A. Without a complete understanding of the circumstances in each of those rate filings and specific ratemaking treatment in those other jurisdictions, it would be difficult to weigh the relevance of the examples he cites. We just don't know the specific circumstances.

Moreover, as noted above, UNS Gas has taken a number of steps to protect our customers, especially our low income customers.

B. <u>Call Center Expense.</u>

Q. Did Staff address its Call Center expense adjustment?

A. Yes. Staff witness Dr. Fish reiterated his assertion that UNS Gas test year call center expense had increased by to much relative to the amount approved in the last filing. Dr. Fish asserts that UNS Gas has not substantiated the increased cost.

Q. Do you agree with Dr. Fish's assertions?

A. No. In my Rebuttal Testimony I provided substantial information regarding the fact that call center cost had only increased 22% since 2005 despite continual additions of services and new equipment. In Dr. Fish's own Surrebuttal testimony he states, "The issue is really not the allocation method, but that the call center costs seem to be increasing at an alarming rate." Well as I point out in my Rebuttal Testimony, the cost of the call center is not the driver of the increase to UNS Gas – it is cost allocation. Simply put, the customers of UNS Gas are using substantially more of the call center resources then were allocated to them in the last UNS Gas rate case. As I explained in my Rebuttal Testimony, call volume from UNS Gas customers has increased, as has call duration. Further, the call center has added additional services for our customers, such as credit card processing and on-line bill presentment. It is not reasonable to limit UNS Gas to 2005 call center expense levels, when call volume, call duration and services have all increased.

C. **Bad Debt Expense.**

Q. Did Staff address pro forma bad debt expense in Surrebuttal?

A. Yes. Dr. Fish reiterated the Commission's position that allowance for doubtful accounts had increased from $366,000 to $1,220,000, which is an increase of 300 percent. He then goes on to misconstrue my Rebuttal testimony by saying that, "Mr. Dukes suggests that he takes offense that Staff might question the appropriateness of the reserve for bad debt, but he believes it is reasonable to fail to recognize losses in a timely manner."

Q. Do you have any additional comments to make on the bad debt expense testimony of Dr. Fish?

A. Yes. Dr. Fish wants you to focus on one side of the ledger and ignore the other. My comment in Rebuttal of taking offense is not based on the balance of the allowance account, but the assertion that Dr. Fish is making that we have "overstated bad debt expense" in the neighborhood of $700,000 sometime in the last three years. His argument to reduce pro forma bad debt expense **only** makes sense if he is arguing that we over expensed in the last three years, thus overstating our allowance account and thus our historical write-off percentage being applied to pro forma revenue – which in turn would overstate pro forma bad debt expense.

The problem with that whole argument is that it simply ignores the facts and the information I provided in my rebuttal testimony and in response to data requests. The allowance account is not overstated because of the over expensing of bad debt. The allowance account is higher to reflect the fact that accounts receivable has a higher amount of uncollectible accounts that have not been written off. When you write off uncollectible accounts there is no impact on the income statement – the expense impact was recognized when the revenue was recorded. When you write off uncollectible accounts you simply

reduce accounts receivable and reduce allowance for doubtful accounts by equal amounts. That is why these two accounts are not mutually exclusive; the true accounts receivable balance is the net of accounts receivable and allowance for doubtful accounts.

In December 2005, the accounts receivable balance of UNS Gas was just over $12 million, and only $181,514 in accounts over 90 days were past due. But in June 2008, the accounts receivable account was just over $7 million, but had over $1,216,156 in accounts 90 days past due included within it. That is why the allowance account is so much higher – not overstated bad debt expense.

D. <u>Outside Legal Expense.</u>

Q. Did Staff address pro forma outside legal expense in their Surrebuttal?

A. Yes. Staff witness Dr. Fish stated that I provided no substantive reasons for the high level of legal expenses being requested in our filing.

Q. Do you agree with Dr. Fish's assessment?

A. No. UNS Gas provided significant support for its request. Besides the fact that my adjustment is based on actual historical expense levels and the information I provided in my Rebuttal testimony, UNS Gas provided responses to a multitude of data requests providing additional support for its requested level of expense. Those responses included projected legal costs that are much closer to UNS Gas's proposed expense level than the artificially low, anomalous levels proposed by Staff.

Q. What about RUCO?

A. Mr. Smith continues to oppose the pro forma level of outside legal cost being requested by UNS Gas. Mr. Smith essentially argues that the level of outside legal expenditures has

declined since the last rate case and that circumstances have changed with some additional level of expenditure sharing in EPNG FERC cases with TEP. He offers a significantly reduced level of pro forma expense $171,865, which is $88,310 more than the level proposed by Staff, but $217,674 less than the Company's request which is based on historical spending levels.

Q. Do you agree with Mr. Smith's assessment?

A. No, but Mr. Smith has raised a valid issue with the sharing of cost of EPNG application monitoring with TEP. But this issue will not have as great a near term impact because the cost sharing with TEP does not apply to Transwestern (including is upcoming rate case) because TEP is not a customer of Transwestern. However, the sharing of the cost for EPNG monitoring should be considered as a potential reduction of future outside legal cost levels for UNS Gas.

Q. So do you believe that your pro forma outside legal cost should be reduced?

A. At this time I do not have any known and measureable information to support a reduction to the historical average level, however if the Commission were to compromise between RUCO's position and the Company's I could support such a proposal and we would monitor closely how the sharing impacts future cost levels and adjust accordingly in our next rate filing.

Q. What about the issues not addressed in this rejoinder testimony?

A. All those issues remain the same as stated in my rebuttal testimony, and UNS Gas has not changed is position on any of those issues.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Moody's Investors Service

Global Credit Research
Credit Opinion
23 JUL 2009

EXHIBIT
UNSG-19
ADMITTED

Credit Opinion: UNS Gas, Inc.

UNS Gas, Inc.

Tucson, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Senior Unsecured	Baa3
Ult Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

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Opinion

Rating Drivers

Stable regulated operations with in historically challenging regulatory environment

Limited non-regulated exposure and ring-fencing

Strong credit metrics

Cross-support within UES family

Corporate Profile

UNS Gas, Inc. (UNSE: Baa3 senior unsecured (guaranteed), stable) is local distribution utility serving approximately 146,000 retail customers in Arizona. UNSG and UNS Electric, Inc. (UNSE: Baa3 senior unsecured (guaranteed), stable), a regulated electric utility in Arizona, are both subsidiaries of UniSource Energy Services (UES) which is the guarantor. UES is a wholly owned subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of certain subsidiaries), stable), whose largest subsidiary is Tucson Electric Power (TEP: Baa3 senior unsecured, stable), a regulated electric utility in Arizona.

SUMMARY RATING RATIONALE

The Baa3 rating assigned to UNSG's senior unsecured notes reflects the interdependence that currently exists between the company and its affiliate UNSE as a result of their shared credit facility and parental guarantee from UES. The rating reflects our view of the consolidated credit quality of UES, which guarantees the debt of both UNSG and UNSE. On a stand-alone basis, UNSG has a credit profile moderately better than its rating as evidenced by metrics that map to rating levels within the LDC gas utility methodology that are somewhat stronger than its rating category.

DETAILED RATING CONSIDERATIONS

Regulated operations in historically challenging environment

Virtually all of UNSG's operations are regulated. Moody's generally views a significant percentage of regulated

operations as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the regulatory environment of Arizona, which Moody's generally ranks below average for U.S. regulatory jurisdictions in terms of expectation of timely recovery of costs and predictability of rate decisions. Moody's also notes that three new commissioners began their term in January 2009 and it is not clear how or whether this might impact Moody's perception of the regulatory environment in Arizona over time.

Regulatory lag continues although moderating capital expenditures are a mitigant

UNSG's last fully litigated rate case was resolved in approximately 16 months with new rates in place reflecting a historic test year that ended two years before the decision. This level of regulatory lag makes adequate and timely recovery difficult to achieve. UNS Gas filed a general rate case in November 2008 requesting a $10 million rate increase (6%) premised on an 11% ROE and 50% equity ratio using a June 2008 test year end. A decision is expected by late 2009 or early 2010. Moody's expects further need for rate cases over the medium-term due to regulatory lag and on-going capital expenditures. The utility is not expected to earn its 10% allowed ROE during this time unless it receives adequate rate relief.

Capital expenditures were above $22 million annually from 2005-2007 but are expected to generally remain below $20 million over the near-term. Moderating capital expenditures reduces the need for regulatory relief though lag is expected to continue.

Effective recovery of purchased gas costs

UNSG has a gas cost recovery mechanism that appears to be functioning adequately. The Purchased Gas Adjustor mechanism may be changed monthly based on a comparison of rolling twelve-month average actual gas cost and gas costs in base rates, though there are limits to the levels of adjustments over a twelve month period. UNSG may also request a surcharge to recover deferred balances. As of March 31, 2009, UNSG had a $6 million over recovered purchased gas costs balance included as a current liability.

Due to the traditionally challenging regulatory environment in Arizona, as well as the uncertainty surrounding the impact of new commissioners, the regulatory supportiveness factor has been scored in the Ba range in the LDC methodology framework.

Non-regulated exposure and ring-fencing within UES is limited

Although UNSG's risk of exposure to non-regulated activities is considered quite modest as both UNSG and UNSE are fully regulated, there is significant interdependence between the UES subsidiaries in the form of a shared credit agreement and parental guarantee. Services are also shared with UniSource's primary regulated utility TEP. UNSG contributed approximately 63% of consolidated UES' EBIT and 14% of consolidated UNS' EBIT.

The Arizona Corporation Commission (ACC) has not restricted UNSG's ability to pay dividends to its parent; however, the utility has not paid a dividend over the last several years. There are dividend restrictions under the company's notes and credit agreement, but UNSG is well within the limits imposed by these documents. Overall, ring-fencing at UNSG maps within the Baa criteria outlined in the LDC Methodology.

Cross support of debt within UES constrains rating

The rating also recognizes the position of UNSE and UNSG as indirect subsidiaries of UNS through UES. UES is an intermediate holding company with no operations or debt. Debt at UNSE and UNSG is guaranteed by UES, which creates cross-support. UES has not historically received any dividend payments from its utility subsidiaries, and none are anticipated for the foreseeable future. UNS has periodically contributed equity to UNSG in support of its capital program and to strengthen its balance sheet.

Improved metrics provide credit support for weaker regulatory environment

Credit metrics overall reflect on-going regulatory lag issues as well as the benefits of cost controls, and a modest debt profile.

ROE, EBIT/Customer and EBIT/Interest

UNSG's average ROE, EBIT/Customer and EBIT/Interest have historically mapped to the lower Baa/high Ba level. In 2008, metrics improved moderately due to the impact of the base rate increase in late 2007 and slowing customer growth; however, they continue to map to the high Ba/low Baa level. UNSG's metrics could improve moderately within the Baa rating range if regulatory lag is reduced or the company receives better than anticipated rate relief.

RCF/Debt, Debt to Capitalization and FCF/FFO

UNSG's cash flow and debt-related credit metrics have historically mapped to the upper Baa/low A level. Retained and free cash flow have improved as UNSG has not paid dividends to its parent recently and capital expenditures have begun to decline. This has allowed retained earnings to increase equity capitalization and also reduce the need for new debt financing. Continued moderating levels of capital expenditures are expected to increase free cash flow and debt financing is expected to be minimal over the near-term. Beyond 2010, free cash flow is expected to once again become negative unless rate relief is better than anticipated. Over time, these metrics could improve to the low A range.

Liquidity Profile

UNSG's cash flow profile has generally been stable with operating cash flow approximately covering capital expenditures; however, in 2008, cash from operations of $2.8 million were significantly below capital expenditures of approximately $16 million. Cash on hand was used to meet the shortfall as cash flow was significantly impacted by collateral postings and refunds from over-recovered purchased gas costs. Over the near-term, capital expenditures of $19-21 million annually are expected to continue to be funded roughly by cash flow from operations.

UNSG has two $50 million issues of senior unsecured notes outstanding, one maturing in August 2011 and one maturing in 2015. UNSG's short term liquidity needs are supported by a joint UNSG/UNSE $60 million credit facility which matures August 2011. Either borrower may borrow up to a maximum of $45 million, so long as the combined amount does not exceed $60 million. As of March 31, 2009, there were no amounts drawn on the facility but UNSE had $17 million of letters of credit outstanding and UNSG had $5 million of letters of credit outstanding which reduced availability under the facility.

The UNSG/UNSE credit facility contains two financial covenants applicable to each borrower: for UNSE a maximum debt to capital ratio of 65% and a minimum interest coverage ratio of 2.25 times, for UNSG a maximum debt to capital ratio of 67%, and a minimum interest coverage of 2.25 times. As of March 31, 2009, the ratios were 54% and 4.01 times at UNSE and 50% and 4.02 times at UNSG. The credit facility requires a material adverse change (MAC) representation at each new borrowing. In Moody's opinion, the requirement of a MAC representation significantly increases the risk that the credit facility may not be available when liquidity needs are greatest.

Moody's assumes that UNSG will manage the amount of its near term obligations within the limits of its available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook for UNSG reflects our expectations of continued stable or modestly improved cash flows resulting from expected rate case decisions, an assumption that any increases in the cost of gas will continue to be recovered on a relatively timely basis, and our understanding that future capital expenditures will be financed in a manner intended to maintain UNSG's current level of financial strength and flexibility.

What Could Change the Rating - Up

UNSG's rating is currently constrained by its interdependence with UNSE and our view of the consolidated credit quality of UES. In the event this interdependence was reduced while UNSG retained its similar credit profile, the rating or outlook could be revised upward. Alternatively, if there were to be an improvement in the consolidated credit quality of UES, this could result in positive rating action for UNSG.

What Could Change the Rating - Down

A downward revision could occur if there is deterioration in the credit quality or ratings of UES or UNSE or UNSG credit metrics decline to the low Baa/high Ba range, for example, RCF/Debt below 10% or EBIT / Interest coverage of less than 2x, or if regulatory support significantly worsens, then there could be a downward revision in the rating or outlook.

Rating Factors

UNS Gas, Inc.

Local Gas Distribution	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Sustainable Profitability (20%)							

a) Return on Equity (15%)				X			
b) EBIT to Customer Base (5%)				X			
Factor 2: Regulatory Support (10%)							
a) Regulatory Support and Relationship					X		
Factor 3: Ring Fencing (10%)							
a) Ring Fencing				X			
Factor 4: Financial Strength and Flexibility (60%)							
a) EBIT/Interest (15%)				X			
b) Retained Cash Flow/Debt (15%)			X				
c) Debt to Book Capitalization (excluding goodwill) (15%)				X			
d) Free Cash Flow/Funds from Operations (15%)			X				
Rating:							
a) Methodology Model Implied Senior Unsecured Rating				**Baa2**			
b) Actual Senior Unsecured Equivalent Rating				**Baa3**			

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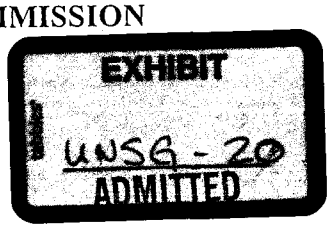
BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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JEFF HATCH-MILLER
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GARY PIERCE

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-____

Direct Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

November 7, 2008

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Exhibits

Exhibit DBE-1 Subsidy of Warmer Districts by Cooler Districts
Exhibit DBE-2(a) Clean version of Tariffs
Exhibit DBE-2(b) Redlined version of Tariffs

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm and my business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP") as a Lead Analyst in the Pricing and Economic Forecasting department. In this role I prepare cost-of-service studies and rate design proposals. I also perform these functions for UNS Gas, Inc. ("UNS Gas").

Q. Please describe your background and work experience.

A. I earned my Master of Science in Economics from Texas A&M University, and my Bachelor of Arts in Economics from the University of Dallas. I have over 25 years of utility experience in the areas of cost allocation and rate design, forecasting, valuation and fair market value determination, and utility mergers and acquisitions. I have testified before state regulators in Arizona, Texas and Alabama on these issues. I testified on behalf of Tucson Electric Power Company ("TEP") in general rates cases during the 1990's on cost allocation, rate design and unbundling to facilitate direct access. I have also provided testimony in the most recent general rates for UNS Gas (2006), UNS Electric, Inc. (2006), and TEP (2007).

Q. What is the purpose of your Direct Testimony?

A. I am sponsoring Schedules G and H, which summarize the class cost-of-service study, rate design and proof of revenue for this filing. I also will sponsor, and my testimony will explain: (i) the weather normalization pro-forma adjustment; (ii) the year-end

customer annualization pro-forma adjustment; (iii) the class cost-of-service study; and (iv) rate design, including phased-in residential customer charge increases. The Weather Normalization and Year-End Customer Annualization pro-forma adjustments are shown in Schedule C-2. Additionally, I will discuss the Company's proposal to meet with interested stakeholders to discuss equitable and effective ways to mitigate the impact of the proposed rate increase on low-income customers and to expand the eligibility of low-income assistance programs.

Q. Could you please summarize your Direct Testimony?

A. First, I am proposing weather normalization and customer annualization adjustments to reflect test-year billing determinants (customer count and usage) under normal weather and year-end customer levels. Commission-approved methodologies were used for both adjustments.

Second, I discuss the Company's class cost-of-service study. As in UNS Gas' last general rate case,[1] I allocated mains and regulators (a substantial component of non-commodity costs) on proportional responsibility and customer costs on weighted customers; these methods were approved in that last general rate case. The cost-of-service study follows the traditional "functionalize, classify, and allocate" structure previously approved in the Company's prior rate cases.

Third, I discuss the Company's rate design proposals. To enhance revenue stability and geographic equity among weather-sensitive customers (including residential customers), the Company is proposing modest customer charge increases for each customer class. These higher customer charges help shield cost recovery from the uncertainties of fluctuating weather-sensitive therm usage, which is appropriate because costs (except for

[1] Docket No. G-04204A-06-0463; Decision No. 70011 (November 27, 2007).

the commodity cost of gas) are largely fixed. Weather fluctuations result in a mismatch between utility expenditures – which are not significantly weather sensitive - and receipts – which under the current rate design are highly weather sensitive. The Company proposes that residential customer charges be increased in three phases to smooth the transition to more cost-based customer charges. Phase 1 ($8.50 to $10) will begin when rates go into effect pursuant to the order in this case, and will continue for one year. Phase 2 ($10 to $12) begins at the one year mark and continues for an additional year, and Phase 3 ($12 to $14) follows – beginning two years after the initial Phase 1 implementation. There would be a corresponding revision to the volumetric charge for each phase to achieve revenue neutrality.

Finally, I will discuss the Company's proposal to meet with interested stakeholders to try to reach a consensus on the modification and expansion of low-income assistance programs.

II. WEATHER NORMALIZATION.

Q. What is the purpose of a weather normalization adjustment?

A. A weather normalization adjustment is performed to represent test-year sales, revenues and costs under normal weather conditions. Energy consumption for several UNS Gas customer classes is weather sensitive. For instance, a significant portion of energy usage in the winter comes from space heating. Some winters, however, are cooler than normal and the Company receives more revenues, and incurs more costs, as a result. This is because it takes more energy for customers to warm their homes and businesses when the average temperature is lower during the winter months. But a warmer than normal winter can result in the Company receiving less revenue and incurring less cost, because less energy is needed to heat homes and businesses. Hence, the purpose of weather

normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues and incur as costs during a particular year. In other words, the weather normalization adjustment quantifies the change in therm sales, revenue and costs that would have occurred if the weather in the test-year had been typical.

Q. How is annual usage normalized based on the weather in order to make this adjustment?

A. The industry uses a variable known as heating degree days ("HDD") to measure the severity of weather. Gas heating requirements are small when average daily temperatures are greater than 65 degrees Fahrenheit. In other words, customers will generally have no need for heating when temperatures are at or above 65 degrees Fahrenheit. Therefore, a HDD is measured by subtracting 65 degrees from the average of the maximum and minimum temperature for that day. Negative results for HDD calculations are set to zero.

Actual HDDs for the UNS Gas service area are then compared to what the typical or normal weather has been in those areas. The normal weather for each calendar month is then determined as the average of monthly HDDs that have been recorded over the last ten years.

Q. Please explain further the weather normalization calculation.

A. To quantify how much gas usage changes in response to weather deviating from normal, the statistical technique of linear regression analysis was used. Regression analysis is used to estimate how much a dependent variable "y" (*e.g.*, average use-per-customer ("UPC")) changes in response to some change in an independent variable "x" (*e.g.*, HDD). This estimate, the slope coefficient (rise over run), represents the change in "y" divided by the change in "x." Specifically, the analysis focused on the consumption

behavior of a single average customer – on this customer's UPC. Regression models estimate how much gas UPC changed in response to a change of one HDD. To put it another way, regression estimates the change in an average customer's monthly gas usage associated with a one degree (Fahrenheit) change in each hour of a single day's temperature (a one HDD change).

This analysis is conducted by month, by class, and by geographical area. A monthly analysis recognizes that the impact on UPC of HDD varies by month. UNS Gas has six distinct geographical areas (referred to in Company documents as "Trend Areas") - Flagstaff, Kingman, Nogales (Santa Cruz county), Prescott, Verde, and Show Low.

When regression is used for weather adjustments, one multiplies the slope coefficient (change in UPC/change in HDD) by the deviation from normal weather (*i.e.*, the difference in normal and actual HDD (which is: HDDN – HDDA)). Note that when actual HDD ("HDDA") is greater than normal HDD ("HDDN"), the calculated difference is negative. A negative adjustment here is indicative of a colder than normal month. To normalize UPC, a negative adjustment is added to actual UPC and a normalized UPC lower than the actual UPC results. In this case, we can say that weather was more extreme than normal (i.e., cooler in the winter), on average.

Likewise, when HDDA is less than HDDN, the calculated difference is positive. A positive adjustment here is indicative of a warmer than normal month. To normalize UPC, a positive adjustment is added to actual UPC and a normalized UPC higher than the actual UPC results. In this case, we can say that weather was less extreme than normal (*i.e.,* warmer (less cold) in the winter), on average.

The result of this calculation is the weather adjustment in therms per customer. To obtain the total weather adjustment, the weather adjustment per customer is simply multiplied by number of customers. Since the number of customers should be positive, a negative weather adjustment per customer must result in a negative overall weather adjustment. And a positive weather adjustment per customer must result in a positive overall weather adjustment.

Q. Is a weather normalization adjustment performed for all classes?

A. No. Weather normalization calculations were performed only for weather sensitive classes, as identified through regression analysis. The weather sensitive classes for UNS Gas are residential, commercial, and public authority. Regression analysis revealed no statistically significant relationship between the industrial class' usage and weather; therefore, no industrial weather adjustment is proposed.

Q. What did your calculations show?

A. Overall, weather was more extreme than normal during the test year (*i.e.*, colder in the winter, on average). Therefore, sales were slightly higher than normal resulting in a "negative" adjustment to sales volumes (therms).

Q. What was the effect of weather adjustments on test-year sales volumes?

A. Because sales were slightly higher than normal, it is necessary to make negative adjustments to reflect a "normalized" level of sales. The net result of these weather normalization adjustments was to adjust the total actual sales volumes downward. The weather adjustment was a negative 2,896,863 therms, approximately 2% of sales.

III. CUSTOMER ANNUALIZATION ADJUSTMENT.

Q. What is the purpose of a customer annualization adjustment in the rate-making process?

A. Customer annualization adjustments should restate the number of test-year bills and volumes to be *consistent with* (but not necessarily *equal to*) the number of customers on the system at the end of the test-year. Customers should expect a positive customer adjustment on a growing system. A positive customer adjustment typically entails additions to both customers and therms.

Q. Is your customer annualization adjustment positive given that the UNS Gas system is growing?

A. No, the adjustment is negative. The customer annualization adjustment, exclusive of an adjustment for a specific industrial customer, is a negative 837,517 therms. This adjustment follows the simple methodology that was supported by both the Staff and RUCO in the Company's last general rate case, and approved in Decision No. 70011. This approved adjustment methodology must now be applied consistently and uniformly to avoid biasing the customer annualization adjustment results.

Q. Why is the customer annualization adjustment negative?

A. Under the methodology approved in Decision No. 70011, the monthly customers during the test year are brought equal to the year-end customer count levels. Assuming that customers grow by a positive amount each and every month, there will be a positive customer annualization adjustment for each month, and therefore a positive overall customer annualization adjustment. Customer counts in early months of the test-year would need to be adjusted upward (a positive adjustment) to bring them to test year-end levels.

However, customer counts on the UNS Gas system often follow a more cyclical, seasonal pattern, with the customer count falling during the summer months. If the test-year ends during the summer (as in this case in June 2008), the test-year-end customer count may be less than some of the monthly customer counts during the previous eleven months of the test year. If months prior to test-year-end have customer counts greater than test year-end levels, the approved annualization methodology will lead to negative annualization adjustments for these months. A negative annualization adjustment means that a month's customer count would need to be adjusted downward to the lower customer count prevailing at test-year end.

In this proceeding, there are enough negative monthly adjustments to tip the net customer annualization adjustment (the sum of all annualization adjustments across months and across classes) negative, even for the growing UNS Gas system. Because the Company's proposal in the last general rate case to adjust for cyclicality in the customer count was rejected by the Commission, I am supporting the proposed negative annualization adjustment on the grounds that it is calculated using the Commission-approved methodology. Had the Company's adjustment for cyclicality been employed in this proceeding's customer annualization, the customer annualization adjustment would have brought monthly adjusted customers to levels adjusted for cyclicality and *consistent* with test-year-end levels – not simply to levels *equal* to year-end levels.

Q. What was the effect of customer annualization adjustments on test-year sales volumes?

A. Adding the negative 837,517 therm adjustment discussed above to a negative customer annualization adjustment of 2,290,881 therms attributable to one of the Company's industrial customers yields a total customer annualization adjustment of a negative 3,128,398 therms.

Q. Please discuss the negative 2,290,881 therm adjustment attributable to the specific industrial customer.

A. One of the Company's industrial customers has dual fuel capability, and used significantly more gas during the test year than during the previous four years. In fact, this industrial customer's usage was over twice as large in the test year than the average over the four years prior to the test year. There is no reason to expect this significantly increased usage to persist during coming periods. In fact, the customer is eliminating a production line at its facility and making job cuts. The negative 2,290,881 therm customer annualization adjustment was calculating by subtracting this customer's test year purchases from average annual purchases for the past five years (with the high consumption test year being the last year in the five year period).

Q. How does the customer annualization adjustment affect test-year customers and sales?

A. Negative customer annualization adjustments affect customers and therms. This means that adjusted billing determinants, both customers and therms, will have been "on average" adjusted downward. I say "on average" because some classes may effectively see customer and/or therm decreases, while other classes may see the opposite. The customer annualization adjustment's customer count varies by class; however, the net effect is as if there is a reduction in "average" customers.

IV. CLASS COST-OF-SERVICE STUDY.

Q. What is the purpose of a class cost-of-service study?

A. The ultimate purpose of a class cost-of-service study is to assign each cost component to the respective classes in order to determine an appropriate total cost to serve each class. An additional purpose is to assign each component a cost "classification" such as demand-related, energy-related or customer-related. A cost component may be one of

three things: (1) an individual rate base or expense account as defined in the FERC Uniform System of Accounts; (2) a portion of a single FERC account (e.g., the "demand-related" portion of an account), or (3) some composite of accounts. Using composites of accounts helps reduce the physical size of the model.

Q. What are the steps in designing a class cost-of-service study?

A. There are three basic steps involved in developing a class cost-of-service study. Those steps are functionalization, classification, and allocation. Functionalization involves grouping cost components by purpose or function. Some examples of functions include distribution mains, distribution regulators, and metering. The class cost-of-service study presented by the Company in this proceeding identifies over twenty different functions. The next step, classification, involves identifying each function as demand-related, energy-related or customer-related. The final step, allocation, involves apportioning each cost component to the classes of service (*e.g.*, residential, commercial and industrial).

Q. Please describe how costs are classified for purposes of the class cost-of-service study.

A. Costs classified as demand are most affected by capacity requirements at the time of maximum (peak) consumption. These demand-classified costs are either coincident, meaning that they occur at the same time, or non-coincident, meaning they occur at times that may vary. Coincident demands tend to be more correlated with the costs of "upstream" facilities (i.e., common facilities serving all customers or the bulk of the customers). Non-coincident demands become more correlated with cost of facilities as we move downstream though the distribution system to the end-users. Non-coincident demands are more localized.

Costs classified as energy are most affected by therm sales by class. Finally, costs classified as "customer" are based on class customer counts – either non-weighted counts or weighted counts. Weighted counts take into account not just the number of customers but the level of costs imposed by the customers. In dealing with billing costs, for example, a residential customer may be defined as one "weighted customer" and an industrial customer that costs 20 times as much to bill would count as 20 "weighted customers."

Q. Please describe the allocation step in designing a class cost-of-service study?

A. As I stated above, allocation involves assigning each cost component to the different classes of service, including residential, commercial and industrial. Each function has a single allocation factor that applies to all cost components in that function. The allocation factor should be based upon an equitable method that harmonizes the cost-causation with the functional cost being considered. In other words, the allocation should be done in a way where the cost-causation for the functional cost considered is properly identified.

Q. Please describe the class cost-of-service study model used in this proceeding.

A. The model, created in Microsoft Excel, starts with cost components by function, known as functionalized costs. The model presents functionalized and classified costs vertically (*i.e.*, in rows down the spreadsheet) and the allocation of costs to rate classes horizontally (*i.e.*, in columns across the spreadsheet). Each functionalized and classified cost is then fully allocated to the customer classes. The percentage of a given cost allocated to a specific class will depend on the function and its associated allocation factor. A cost associated with billing customers, for example, should be allocated so that it reasonably approximates the cost of billing the customers by class. As mentioned above, a weighted

customer basis would be used to derive a factor that reflects both the number of customers by class and the level of costs each customer class imposes.

Q. Are there different types of allocation factors?

A. Yes. Some allocation factors used are "external" allocation factors. External allocation factors are determined independent of the magnitude of specific costs in the class cost-of-service study (i.e. the external allocation factor is developed in an analysis separate from the study). An example of an external allocation factor is distribution mains ("DISTMAIN") listed in the class cost-of-service study as a demand-related factor used for the allocation of distribution mains. This factor is based on the Proportional Responsibility method discussed below.

Q. Are there internal allocation factors?

A. Yes, an internal allocation factor is calculated within the class cost-of-service study model and is dependent on the cost components found therein. For example, Accumulated Deferred Income Taxes are allocated based on Total Plant in Service ("PLANT"). Total Plant in Service is a composite of different plant categories (*e.g.*, intangible, transmission, distribution, and general). To the extent that plant categories are allocated differently, the Total Plant in Service allocator will vary based on the level of different plant types. Total Plant in Service, like all internal allocation factors, is a weighted average of other allocation factors. The relative size of cost components determines the weights in the weighted average.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7. As shown, some factors are "customer-related." Studies on metering, services and meter reading provide the basis for

the customer-related factors. Additionally, there are factors based on labor costs, throughput or internal factors based on individual or aggregate costs.

Q. Please describe the Proportional Responsibility method?

A. The Proportional Responsibility method is based on the respective class' share of total load in each of the twelve months for the test-year. The peak load months are more heavily weighted under Proportional Responsibility. A class' share of total load in low load months has only a small impact on the factor. Several allocation factors, including DISTR, DISTMAIN, DISTREG and TRANS are based on proportional responsibility. Factors such as DISTR, DISTMAIN, DISTREG and TRANS are external factors because the Proportional Responsibility method is based on class loads, and is calculated independently of the magnitude of any cost components. The Proportional Responsibility method drives many significant costs in the class cost-of-service study model.

Q. Has the Proportional Responsibility method been used in a previous general rate case filing?

A. Yes. This method was used and approved in Docket No. G-01032A-02-0598, Decision No. 66028 (July 3, 2003), when the Commission approved the Citizens Communications Company ("Citizens") Settlement Agreement, and in UNS Gas' last general rate case, Docket No. G-04204A-07-0643, Decision No.70011 (November 27, 2007).

Q. Have you allocated your proposed revenue by class so as to generate an equalized return by class, as indicated by your class cost-of-service study?

A. No. Revenues by class were set so that the percentage revenue increases were close to the system average revenue increase, exclusive of gas costs and other operating revenue. This helps mitigate the adverse rate impact on any class. Revenue by class is provided in the G Schedules.

V. RATE DESIGN.

Q. What are the Company's objectives in rate design?

A. The Company has two primary objectives in rate design: i) to more equitably collect the Company's fixed costs; and ii) to expand programs for our low-income customers in collaboration with interested stakeholders.

Q. Please summarize your rate design recommendations.

A. First, UNS Gas proposes an increase in monthly customer charges to levels that better match the true customer-related costs, as indicated by the class cost-of-service study. Under the class cost-of-service study, the "bare bones" monthly customer charges are calculated to be $18.15 for residential service, approximately $19.00 for small commercial/industrial customers and approximately $220.00 for large commercial/industrial customers. "Bare-bones" customer charges restrict the customer classification to metering, meter-reading, service (service drop) to the specific customer, customer service and billing. No demand-related distribution mains or distribution regulators are included, as they may be under a minimum system or zero intercept approach. The "bare-bones" approach leads to relatively low customer charges. However, we do not propose increasing monthly customer charges all the way to the charges suggested by the class cost-of-service study.

For residential service, the increases will be phased-in over two years. Phase 1 will go into effect upon approval of the rate increase. The Phase 2 and Phase 3 rate designs (implemented one year and two years, respectively, after rates go into effect in Phase 1) are based on approved test-year billing determinants, and are revenue neutral with respect to Phase 1 rates, in that test-year proposed revenue remains unchanged. UNS Gas proposes to increase residential customer charges from the current $8.50 per month to

$10.00 per month when new rates are implemented. The proposed rates per therm (exclusive of gas commodity costs) are proposed initially (in Phase 1) to be $0.3920. One year after the rate implementation, UNS Gas proposes a $2.00 per month residential customer charge increase, bringing the customer charge to $12.00 per month in Phase 2. With the increase in the customer charge to $12.00, the volumetric charges will be lowered to achieve the approved revenue requirement. Revenue neutrality is maintained at the one-year mark by lowering rates per therm (exclusive of gas commodity costs) to $0.3479. In Phase 3, commencing two years after rates go into effect, the customer charge is increased to $14.00 and revenue neutrality is maintained at this two-year mark by lowering rates per therm (exclusive of gas commodity costs) to $0.3039. Even in Phase 3, the customer charge will still be less than the $18.15 "bare-bones" customer charge supported by the class cost-of-service study.

Customer charges for non-residential classes generally also are raised closer to levels indicated by the class cost-of-service study. UNS Gas is proposing customer charges of $15.50 for small commercial/industrial customers (from the current $13.50) and $105.00 for large commercial/industrial customers (from the current $100.00). The proposed commercial/industrial charges are aligned more closely to the true costs of providing service. Increased customer charges will aid in the recovery of fixed costs.

Q. Why are customer charges preferred to volumetric (per therm) charges in recovering fixed costs?

A. UNS Gas currently collects the bulk of its fixed costs through a volumetric charge. Within the residential class, however, the periodic variation in throughput has limited impact on the true, non-commodity cost of serving customers Because most non-commodity costs are fixed, there is a potential for a mismatch between costs and revenue if a substantial portion of revenue is recovered through weather-sensitive sales. To help

address this mismatch, customer charges can be increased. When customer charges are increased, volumetric charges are decreased, given a revenue requirement and other things constant. Customer charge revenue does not vary significantly with weather variations within a month, with conservation efforts, or – in the short run – with economic activity. Consequently, customer charges provide a relatively stable and predictable source for funding fixed costs, which constitute the bulk of a gas system's costs (exclusive of the commodity cost of gas, which is a pass-through).

Q. Does the current recovery of fixed costs through volumetric charges create problems other than revenue instability?

A. Yes. First, the collection of significant fixed cost through volumetric charges places a disproportionate burden on larger energy users, which in turn results in a geographical inequity. Customers in cooler areas have higher usage, on average, and pay more than their share of fixed costs. If the Company can shift revenue collection away from volumetric charges, it can minimize the cross-subsidization that occurs when usage within customer classes varies significantly based on geography and climate.

Second, the over-use of volumetric charges for fixed cost recovery creates an economic disincentive to the utility in promoting conservation. If margin is collected primarily through usage (volumetrically), conservation may significantly erode a gas distribution utility's ability to earn its authorized rate of return.

Q. How has the nature of UNS Gas' service territory exacerbated the geographical inequity?

A. Since natural gas usage is driven largely by weather, the Company's current rates have resulted in customers in cooler areas (i.e., districts with more HDDs) subsidizing those living in warmer areas. This disparity is exacerbated by the stark geographic differences

in UNS Gas' service territory, which includes areas that are either among the coldest (e.g. Flagstaff) or the hottest (e.g. Lake Havasu City) parts of Arizona. Customers in the coldest corners of our service territory – those affected most by rising costs on the volumetric, gas commodity portion of their bills during home heating season – have borne the additional burden of subsidizing the fixed cost of serving customers who spend their winters in far more moderate climates.

Q. Have you performed an analysis to illustrate the subsidy of warmer districts by cooler districts?

A. Yes. Attached to my Direct Testimony as Exhibit DBE-1, is a table that shows average annual residential consumption and margin revenue for ten locations in the UNS Gas service territory. Margin does not include the commodity cost of gas. By "margin", I mean the sum of the: (i) customer charge; and (ii) portion of the volumetric charge not related to the commodity cost of gas. Margin covers the costs of customer service, billing, metering, meter reading,. service drop, mains, and other non-gas resources and infrastructure serving UNS Gas' customers. The data illustrates the disparity between what average customers in certain locations contribute to margin. For example, the typical residential customer in Flagstaff currently pays an annual margin (i.e., charges excluding actual gas commodity costs) of $328, $145 more than the $183 paid by the typical residential customer in Lake Havasu (see column 2 of Exhibit DBE-1). Cost-of-service analysis indicates that a $145 margin differential between these two customers is too high. Assuming proposed revenue levels, and a cost-based customer charge of $18.15 per month (which is higher than any of the Company's proposed residential customer charges), the Flagstaff customer pays a $364 margin, which is only $93 more than the $271 paid by the Lake Havasu customer (see column 6 of Exhibit DBE-1).

Because of the different overall revenue levels (i.e., current rates v. proposed rates), a comparison of the average Flagstaff bill as a percentage of the Lake Havasu bill is enlightening. Using the data from Exhibit DBE-1, I have compiled the following table that illustrates how the Company's phased-in increase in customer charges is a movement toward more cost-based rates.

Table 1 – Flagstaff / Lake Havasu Average Annual Bills EXCLUDING Gas Commodity costs

	Current ($8.50)	*Phase 1 ($10)*	*Phase 2 ($12)*	*Phase 3 ($14)*	*Cost-Based ($18.15)*
Flagstaff Bill	$328	$391	$384	$378	$364
Havasu Bill	$183	$218	$231	$244	$271
Difference	$145	$173	$154	$134	$93
Diff as %	79%	79%	67%	55%	34%

The "Diff as %" shows the difference in Flagstaff and Lake Havasu bills as a percent of Lake Havasu bills. This line shows that under cost-based rates an average Flagstaff bill should be only 34% higher than the average Lake Havasu bill. Currently, the average Flagstaff bill is 79% higher than the average Lake Havasu bill. Between Phases 1 and 3 of the proposed customer charge implementation, the excess of Flagstaff over Lake Havasu bills falls from 79% to 55%, which is a marked improvement and a movement to cost-based rates.

Q. How do you respond to the criticism raised in past rate cases that the Company is just seeking to recover through higher customer charges as much of its margin as possible and that such a rate design will encourage greater use of natural gas at a time when an increase in natural gas demand is coupled with shortages of supply?

A. I disagree with both criticisms. While a utility is always seeking to earn its authorized return, the main driver for our rate design is to resolve a gross inequity in the current rate design that adversely impacts cold weather customers, leads to revenue instability, and constitutes an economic disincentive for promoting conservation.

The Company's rate design hardly guarantees achieving its authorized rate-of-return ("ROR"). A significant percentage of margin recovery will still be collected through the volumetric charges, even in Phase 3 of the residential customer charge increases. Focusing on residential R-10 (the main residential rate responsible for approximately 69% of system margin revenue), 64% of margin currently is collected volumetrically, and only 36% is collected through customer charges. Based on costs, and pursuant to the class cost-of-service study, approximately 17.5% of the margin should be calculated volumetrically (through per therm charges), another 17.5% should be collected through some type of demand or reservation charge (not used in current nor proposed rates), and the remaining 65% should be collected through customer charges. For simplicity, I will combine the volumetric and demand components (each 17.5%) into a single volumetric component (35%). Some cost analysts would split the 17.5% demand component between the customer and volumetric components, instead of assigning it solely to the volumetric component, as I have done for simplicity. Such a splitting of the 17.5% demand component supports collecting *more* than 65% of residential margin through customer charges, but would move away from my "bare-bones" approach to customer charges.

In summary, around 36% of residential margin is currently collected through customer charges, but the class cost-of-service study indicates that at least 65% of residential margin should be collected through customer charges. This cost-based residential result is almost a complete reversal of the current situation. UNS Gas' current rates are mostly driven by the volumetric component, while the Company's costs are mostly fixed. The goal of having residential rates match cost causation is currently not being met. Furthermore, the analysis below demonstrates that this goal is not fully met under the proposed rates either, though there is some movement toward the goal.

Q. Please discuss the recovery of residential margin revenue under the Company's proposed phased-in customer charge increase.

A. The table below shows that even in Phase 3 of the residential customer charge increase, the percentage of margin recovery through customer charges falls short of the 65% cost-based target.

Table 2 – Percentage of Residential R-10 Margin Collected through Customer Charges

Residential R-10 Rate	*Percent Collected Through Customer Charge*
Current ($8.50/mo.)	36%
Proposed - Phase 1($10.00/mo.)	36%
Proposed - Phase 2 (One year after new rates become effective) ($12.00/mo.)	43%
Proposed - Phase 3 (Two-years year after new rates become effective) ($14.00/mo.)	50%
Cost-of-Service Target ($18.15/mo.)	65%

The 65% cost-based target is not met, but the Company's proposed rate design is a movement in the right direction. The Company's customer charge proposal is a balance between limiting bill impacts and mitigating undue subsidization of warmer areas by

cooler areas. I believe this is consistent with the Commission's resolution of the customer charge issue in Decision No. 70011.

Q. Will the increased customer charge reduce the incentive to conserve?

A. Not materially. The proposed customer charges and volumetric charges will provide the appropriate incentive to conserve – neither too little incentive nor too much incentive - given cost considerations and the relative prices of energy substitutes like electricity, propane and firewood. Despite the fact that higher customer charges result in lower volumetric charges, customers will still have plenty of incentive to conserve natural gas because they avoid some very significant gas commodity costs. The commodity cost of natural gas has been increasing at around 2.5 times the rate of inflation over the last four years. Customers pay for the amount of natural gas they actually consume through UNS Gas' PGA. The gas commodity portion of the average residential bill is even greater (approximately 60%) than the margin portion (approximately 40%). The substantial commodity portion will continue to provide customers a strong incentive to conserve natural gas.

Q. Have you considered other mechanisms for addressing the current mismatch between revenues and costs and the resulting cross-subsidization between customers?

A. Yes. UNS Gas considered a recurring "reservation" (demand) charge based on a customer's maximum usage over the past twelve months. To the extent that potential peak requirements affect sizing of facilities to the end-use customer, this reservation charge could help match billing to cost-causation, which is desirable for an equitable rate design. As mentioned, around 17.5% of residential revenue could be recovered through the reservation charge, based on the cost-of-service study. However, this would be a major change in rate structure and may be better suited for a future proceeding.

VI. LOW-INCOME PROGRAMS.

Q. Is the Company proposing any changes to its CARES pricing plan in its initial testimony?

A. Yes. UNS Gas proposes to increase the non-CARES residential rate but *not* the CARES rate; the rates are "de-linked" in that the proposed CARES rate is no longer simply the non-CARES residential rate with $0.15 per therm subtracted from the price for the first 100 therms in the billing months of November through April. The Company is retaining the CARES pricing plan, and proposes to hold the customer charge and the non-commodity volumetric charges at current levels. Also, CARES customers will not see the phased-in customer charge increases applicable to the non-CARES residential rate.

Q. Please discuss your proposal to have interested stakeholders meet to discuss the potential expansion of low-income programs.

A. UNS Gas supports a collaborative effort of interested stakeholders aimed at providing a discount in the commodity cost of gas to CARES customers and/or establishing a discount through a gas cost cap specifically for CARES customers. These discounts would be fully recoverable though the Purchased Gas Adjustor ("PGA") from other retail customers. Stakeholders would discuss the level and applicability of any discounts. Gas costs discounts would represent an expansion of the package of discounts already applicable to CARES customers and *could* provide certainty that, after the proposed rate implementation, that CARES customers will see an effective "all-in" price (inclusive of gas costs) at or below any effective "all-in" price under current rates. UNS Gas will work quickly to schedule these meetings with stakeholders after the filing of this case to discuss low-income programs. In the event that consensus is reached, UNS Gas will file testimony in support of agreed-upon modifications to the CARES program. In the event that the Commission accepts any PGA discounts and/or a PGA cap for CARES

customers, a conforming change to the Company's PGA mechanism will also be required.

Q. Does UNS Gas support the expansion of assistance programs beyond the CARES-eligible group?

A. Yes. UNS Gas recognizes than there are residential customers with income exceeding 150% of poverty level who are not eligible for the CARES program, but who struggle to pay utility bills. The Company proposes to meet with interested stakeholders, and collaboratively design a program for needy customers who do not qualify for CARES. One possible approach, for example, would be to design a program for customers with incomes between 150% and 200% of the poverty level. The specifics, including eligibility requirements and discount levels of the program, would be worked-out collaboratively among the stakeholders. The Company's support is conditioned on the program: i) being fully-funded by other retail customers, preferably through the PGA; and ii) being billable through the customer information and billing system. Assuming that consensus can be reached on a new customer assistance program, the Company will file testimony supporting it.

VII. PROPOSED TARIFF.

Q. Are UNS Gas' proposed tariffs included with your Direct Testimony?

A. Yes, the proposed tariffs are attached to my Direct Testimony as Exhibits DBE-2 (a) (clean copy) and DBE-2 (b) (redlined copy).

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

DBE-1

UNS Gas - Test Year Ended June 30, 2008
Residential Use and Margin by Location

Location	Typical Annual Usage (Therms) (1)	Average Annual Margin Present (2)	Average Annual Margin Proposed "Phase 1" (3)	Average Annual Margin Proposed "Phase 2" (4)	Average Annual Margin Proposed "Phase 3" (5)	Average Annual Margin COS Rate (6)
Flagstaff	691	$328	$391	$384	$378	$364
Sedona	677	$323	$385	$380	$374	$362
Winslow	642	$312	$372	$367	$363	$354
Holbrook	620	$305	$363	$360	$356	$349
Show Low	607	$300	$358	$355	$352	$347
Prescott	567	$287	$342	$341	$340	$338
Kingman	400	$233	$277	$283	$290	$303
Cottonwood	436	$245	$291	$296	$301	$310
Santa Cruz	408	$235	$280	$286	$292	$304
Lake Havasu	249	$183	$218	$231	$244	$271
Average	545	$280	$334	$334	$334	$334

(Column 1) Does not include unbilled usage.

(Column 2) The present residential customer charge is $8.50 per month and the volumetric margin rate is $0.3270 per therm.

(Column 3) Phase 1 - The 1st year proposed residential customer charge is $10.00 per month; the volumetric margin rate is $0.3920 per therm.

(Column 4) The Phase 2 (after 1 year) proposed residential customer charge is $12.00 per month; the volumetric margin rate is $0.3479 per therm.

(Column 5) The Phase 3 (after 2 years) proposed residential customer charge is $14.00 per month; the volumetric margin rate is $0.3039 per therm.

(Column 6) The COS residential customer charge is $18.15 per month; the hypothetical volumetric margin rate is $0.2123 per therm.

EXHIBIT

DBE-2

UNS GAS, INC.
TARIFFS

CLEAN VERSION

FOR TEST YEAR SEPTEMBER 30, 2008

UniSource ENERGY SERVICES

UNS Gas, Inc.

Pricing Plan Summary

Pricing Plan	Pricing Plan Title	Therm Limits	Effective Date	Customer Charge	Charge per Therm (Excluding CNG)	ACC Decision
R-10	Residential Gas Service		XX/X/XX	$10.00	$0.3920	XXXXX
R-10	Residential Gas Service		XX/X/XX	$12.00	$0.3480	XXXXX
R-10	Residential Gas Service		XX/X/XX	$14.00	$0.3039	XXXXX
R-12	C.A.R.E.S. ($0.15 discount applicable for billing months of November - April)		XX/X/XX	$7.00	Summer $0.327000 Winter $0.177000	XXXXX
C-20	Small Volume Commercial Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.3168	XXXXX
C-22	Large Volume Commercial Service	> 120,000 therms	XX/X/XX	$105.00	$0.2054	XXXXX
I-30	Small Volume Industrial Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.2808	XXXXX
I-32	Large Volume Industrial Service	> 120,000 therms	XX/X/XX	$105.00	$0.1136	XXXXX
PA-40	Small Volume Public Authority Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.3104	XXXXX
PA-42	Large Volume Public Authority Service	> 120,000 therms	XX/X/XX	$105.00	$0.1430	XXXXX
PA-44	Special Gas Light Service		XX/X/XX	Various		XXXXX
IR-60	Irrigation Service		XX/X/XX	$15.50	$0.3804	XXXXX
CGS-1	Competitive Gas Service	> 10,000 therms	XX/X/XX	Negotiated		XXXXX
CNG-1	Compressed Natural Gas Service		XX/X/XX	Various		XXXXX
EC-1	Electric Cogeneration Service		XX/X/XX	$105.00	$0.0488	XXXXX
MISC-1	Miscellaneous Service Fees		XX/X/XX	Various		XXXXX
NSP-1	Negotiated Sales Program		XX/X/XX	Negotiated		XXXXX
T-1	Transportation of Customer-Secured Natural Gas	> 120,000 therms	XX/X/XX	Otherwise applicable base rates less embedded gas costs		XXXXX
T-2	Transportation Service Using Dedicated Transmission Facilities	> 120,000 therms	XX/X/XX	See tariff for detail of applicable charges		XXXXX
RR-1	Purchased Gas Adjustment		XX/X/XX			XXXXX
RR-2	DSM Adjustor		12/1/07	N/A	$0.0025 per therm	Decision No. 70011

NOTE

All sales pricing plans above include a Cost of Natural Gas Charge (CNGC) which recovers the cost of natural gas purchased by UNSG on behalf of its customers.

The CNGC rate shall be subject to increases or decreases by the amount of the Purchased Gas Adjustment in accordance with the provisions of Rider RR-1

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-10
Residential Gas Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Subject to availability, at point of delivery, to residential gas service in individual residences and individually metered apartments when all service is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month as of mm-dd-yyyy @	$10.00
Minimum Customer Charge per month as of mm-dd-yyyy @	$12.00
Minimum Customer Charge per month as of mm-dd-yyyy @	$14.00
Delivery Charge per therm as of mm-dd-yyyy @	$0.3920
Delivery Charge per therm as of mm-dd-yyyy @	$0.3480
Delivery Charge per therm as of mm-dd-yyyy @	$0.3039

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

5. Customers who wrongfully declare eligibility or fail to notify the Company when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential pricing plan.

6. It is the responsibility of the customer to notify the Company within thirty (30) days of any changes in the customer's eligibility status.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSource Energy SERVICES

UNS Gas, Inc.
Pricing Plan C-20
Small Volume Commercial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all commercial customers whose primary business activity at the location served is not provided for under any other pricing plan, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery, and whose gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50
Delivery Charge per therm @	$0.3168

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas ajustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan C-22
Large Volume Commercial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all commercial customers whose primary business activity at the location served is not provided for under any other pricing plan and whose preceding twelve (12) month usage exceeded 120,000 therms. Service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this schedule may not return for a period of twelve (12) billing periods.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105.00
Delivery Charge per therm @	$0.2054

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan I-30
Small Volume Industrial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all customers whose gas usage does not exceed 120,000 therms per year, who are served through a single meter, and whose primary business activity at the location served is included in one of the following classifications of the North American Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors;
Sector 22. Utilities: Power Generation Subsectors only; and
Sectors 31-33. Manufacturing: All Subsectors.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50
Delivery Charge per therm @	$0.2808

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSource Energy SERVICES

UNS Gas, Inc.
Pricing Plan I-32
Large Volume Industrial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all customers whose gas usage over the preceding twelve (12) months exceeded 120,000 therms, and whose primary business activity at the location served is included in one of the following classifications of the North American Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors;
Sector 22. Utilities: Power Generation Subsectors only; and
Sectors 31-33. Manufacturing: All Subsectors.

Service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.
Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105.00
Delivery Charge per therm @	$0.1136

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-40
Small Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery and gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50
Delivery Charge per therm @	$0.3104

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSource Energy SERVICES

UNS Gas, Inc.
Pricing Plan PA-42
Large Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract. Under this pricing plan, usage over the preceding twelve (12) months must exceed 120,000 therms when all service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105.00
Delivery Charge per therm @	$0.1430

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-44
Special Gas Light Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the facilities served.

APPLICABILITY
To all public authority customers for the operation by the Company of gas lights for streets in which gas distribution facilities are located.

RATE
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

Single Orifice @	$21.57
Double Orifice @	$43.13
Triple Orifice @	$64.70
Quadruple Orifice @	$86.27

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

CONDITIONS

1. Contracts for gas lighting service under this pricing plan must be for a minimum term of five (5) years.

2. The cost of relocation of any gas light that is requested by the customer will be reimbursed to the Company by the customer.

3. The customer is not authorized to make any connections to gas lines serving individual gas lights or make any alteration of such lights.

4. The Company will use diligence in maintaining gas lighting service and monthly bills will not be reduced because of any gas light outage.

5. Any special contracts for public authority lighting will be based on an analysis of costs of operation, maintenance, and investment. Any contracts pursuant to this pricing plan, which provide for higher rates than set forth in this pricing plan, will be filed with the Arizona Corporation Commission for approval.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan IR-60
Irrigation Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
To all irrigation customers whose primary business activity at the location served is not provided for under any other pricing plan, who operates one or more gas-fueled engines, and gas is metered through one meter.

The Company may require that gas for engine use be separately metered and billed if necessary to prevent abuse or inequity in the application of this rate.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50
Delivery Charge per therm @	$0.3804

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-1 Supplementary Information
Transportation of Customer-Secured Natural Gas

Transportation customers procure their own gas and UNS Gas, Inc. ("Company") transports it from the connection with the interstate pipeline (at the city gate) over the Company's pipeline system to the customer's facility. To qualify, customers must use a minimum of 120,000 therms per year.

The rates per therm for transportation service from the city gate to the customer's facility are as follows:

Large Volume Commercial	$0.2054 per therm
Large Volume Industrial	$0.1136 per therm
Large Volume Public Authority	$0.1430 per therm

Customers must also pay for the following items:

1. Charges for lost and unaccounted for gas in accordance with Pricing Plan T-1 (Transportation of Customer-Secured Natural Gas);
2. A minimum Customer Charge of $105 per month;
3. Telemetering equipment and a telephone line; and
4. The costs for delivery of gas to the city gate.

AVAILABILITY

This pricing plan is available to any qualifying Customer for transportation of natural gas by the Company from existing interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's system throughout its certificated Arizona Gas Service Area under the following conditions:

1. The Company has available capacity to render the requested service without construction of any additional facilities, except as provided by this pricing plan under Facility Additions..

2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities, and for a term compatible with the service being requested from the Company.

3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User.

4. The Customer's gas to be transported is greater than 120,000 therms per year. A Customer receiving service from the Company at multiple locations may aggregate meters with annual consumption of no less than 50,000 therms per meter to qualify for this service provided that all meter locations are served under a single entity. In addition, the annual consumption of customers that are aggregated must be greater than 120,000 therms per year.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

   (c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan that requests service under a sales pricing plan is ineligible to return to transportation service for a period of not less than twelve (12) months.

RATES

A discount from the following rates may be offered at the sole discretion of the Company if such discount is in the best interest of the Company and its ratepayers. The maximum amount that the Customer shall pay the Company monthly will be the sum of the following charges:

Customer Charge per Month: $105.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount equal to the applicable unit sales margin for each therm as set forth in the Customer's otherwise applicable sales pricing plan for each meter. This volume charge will cover the Company's Delivery Charge as specified in the currently effective gas sales pricing plan but not including the base cost of gas specified therein.

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas costs on a sales basis and gas costs on a purchase basis determined in the development of the currently effective, Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company, at its sole option, may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under these pricing plans.

Minimun Charge: The minimum charge will be the Basic Customer Charge per Month plus $0.005 per therm.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

(a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

(c) Term of Service:
   i. Date of service requested to commence;
   ii. Date service requested to terminate, if known; and
   iii. Minimum term for transportation service shall be twelve (12) months.

(d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

OPERATING PROCEDURES

1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

   The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

   The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage

exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

3. Quantities: All quantities referred to under Operating Procedures of this pricing plan shall be provided as dekatherms ("DTH") (one million British Thermal Units).

4. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

5. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

6. Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500 therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified in Payment for Excess Quantities of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified in Payment for Excess Quantities are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

   Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described in Facility Additions of this pricing plan or provide daily meter reads each calendar day.

7. Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

8. Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation

Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

9. Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

   (a) Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

   (b) The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

   (c) Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth in Balacing described as part of Operating Procedures herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

(i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

(b) Negative Excess Imbalance

A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

(i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the aggregate negative imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein. For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the section Payment For Excess Quantities above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures hereof, nor shall the section Payment For Excess Quantities or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules and Regulations as approved from time to time by the Arizona Corporation Commission. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges, whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-1 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-1 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the Company's PGA bank, calculated as follows:

(a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Basic Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time to time;

(b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

(c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

3. If a Customer converts back to a pricing plan for gas sales service while the PGA Surcharge existing at the time of the switch to T-1 service is still in effect, such Surcharge will not be applicable to the Customer's billed usage for the period it remains in effect. However, any future PGA Surcharge that may be put into effect will be applicable to the Customer's billed usage.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

CONDITIONS

1. Transportation of Customer-owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan which would otherwise be available to such Customer.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-2
Transportation Service Using Dedicated Transmission Facilities

AVAILABILITY

This pricing plan is only available to any qualifying Customer for transportation of natural gas by the Company from dedicated interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's transmission system throughout its certificated Arizona Gas Service Area under the following conditions:

1. The Company has or will have available capacity to render the requested service utilizing facilities dedicated to the requirements of the Customer, except as provided under Facility Additions hereof;

2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Company;

3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User;

4. The Customer's requirement for gas to be transported is greater than 1,000 therms per day or 120,000 therms per year; and

5. The Customer is not taking service through dedicated facilities under the provisions of a special contract approved by the Arizona Corporation Commission ("ACC").

6. The Customer is classified as a utility that produces electricity.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

(c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan is ineligible to obtain sales service without executing a special contract approved by the ACC.

RATES

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

Customer Charge per month: $105.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount to fund the Company's low income rate program equal to the portion of the applicable unit sales margin for each therm included in rates as set forth in the Customer's otherwise applicable sales pricing plan for each meter.

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas cost on a sales basis and gas cost on a purchase basis determined in the development of the currently effective Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company at its sole option may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under this pricing plan.

Reservation Charge: An annual charge to be billed in twelve (12) equal monthly installments equal to the fully allocated costs to provide the dedicated facilities necessary to serve the Customer as described more fully in Rates of this pricing plan.

Determined on the basis of a fully allocated cost study filed with and approved by the ACC in the context of a general rate case except when the request for service is non-coincident with a rate filing. In the latter case, the Reservation Charge will be computed by the Company including the following elements:

(a) Return and income taxes at the rate of return approved by the ACC in the Company's last general rate case computed on the basis of the installed costs of the dedicated facilities plus an allocation of other rate

base items including, as appropriate: intangible, general and common plant investment, less any applicable accumulated depreciation and deferred taxes, an allowance for working capital and materials and supplies;

(b) Operations expense including all operating and maintenance expenses, depreciation and amortization expense, taxes other than income related to the dedicated facilities and allocated rate base;

(c) Allocated indirect expense including an appropriate portion of customer accounting, sales and information, and administrative and general expenses; and

(d) Any other allocated costs incurred either directly or indirectly to provide the requested service.

Special Surcharge: An annual charge to be computed on the basis of the twelve (12) months ending September of the prior year and billed beginning in January in equal monthly installments, computed as the sum of the following charges:

(a) The revenue requirements for any additional investments required to provide the service requested by Customer subsequent to the establishment of the currently effective Reservation Charge,

(b) Any non-recurring operating and maintenance expenses associated with the facilities dedicated to the Customer in the previous year, and

(c) Any extraordinary expenses incurred by the Company on behalf of the Customer not included in (a) or (b) above.

Minimum Charge: The minimum charge will be the sum of the Basic Customer Charge per Month, the monthly Reservation Charge and any monthly Special Surcharge.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

(a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point, and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

(c) Term of Service:
   i. Date service requested to commence;
   ii. Date service requested to terminate, if known; and
   iii. Minimum term for transportation service shall be twelve (12) months.

(d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

2. Construction Requirements: In the event that the Customer's request for service requires the construction of additional transmission facilities not otherwise addressed in section Payment For Excess Quantities herof, Extension of Lines, in the Company's current Rules and Regulations, the following additional provisions may apply:

(a) The Company may request an advance for engineering and design services based on the Company's estimate of the anticipated costs related to the requested dedicated facilities;

(b) Any advance for engineering and design will be refunded to the Customer on commencement of service;

(c) Actual engineering and design costs will be included in the dedicated facilities' costs and recovered as a part of the Reservation Charge;

(d) If the dedicated facilities are not placed in service for any reason, the Company may retain the advance;

(e) Prior to the initiation of construction of the dedicated facilities, the Company will provide an estimate of the total costs and resulting annual costs to Customer;

(f) The Company shall not be liable for any differences between actual construction costs and estimated costs;

(g) Customer may withdraw the request for service prior to initiation of construction; and

(h) The Customer may request that construction cease prior to completion. However, if the dedicated facilities are not completed or placed in service, the Customer is liable for service under the terms of this pricing plan as if the facilities had been completed, based on the total construction costs expended on behalf of the Customer.

OPERATING PROCEDURES

1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

   The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

3. The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

4. Quantities: All quantities referred to under Operating Procedures shall be provided as dekatherms ("DTH") (one million British Thermal Units).

5. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

6. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

7. Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled

transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500 therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified under Payment For Excess Quantities of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified under Payment For Excess Quantities are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

8. Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described under Facility Additions or provide daily meter reads each calendar day.

9. Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

10. Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

11. Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

12. Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

13. The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

14. Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth under Balacing described as part of Operating Procedures herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

   (a) Positive Excess Imbalance

   A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

   (i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

   (b) Negative Excess Imbalance

   A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

   (i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the aggregate negative imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein. For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the section Payment For Excess Quantities above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures hereof, nor shall the section Payment For Excess Quantities or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules of Service as approved from time to time by the ACC. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges, whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges, and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-2 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-2 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request or completion of any required facilities, whichever is later.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the PGA bank accumulated while served under the Company's sales pricing plan, calculated as follows:

   (a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the Customer's last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Base Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time-to-time;

   (b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

   (c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

CONDITIONS

1. Transportation of Customer owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan, which would otherwise be applicable to such Customer.

UniSource Energy SERVICES

UNS Gas, Inc.
Pricing Plan NSP-1
Negotiated Sales Program

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Available to all customers who receive service under the Company's T-1 pricing plan (Transportation of Customer-Secured Natural Gas), T-2 pricing plan (Transportation Service Using Dedicated Transmission Facilities), or special gas supply agreements approved by the Arizona Corporation Commission ("ACC") that meet the minimum transportation requirements under the T-1 or T-2 pricing plans.

Service under the Negotiated Sales Program ("NSP") will be the sale of natural gas to a transportation customer who has negotiated with the Company for the delivery of natural gas to the interconnection of the Company's distribution system and an upstream pipeline at the City Gate. NSP service will be interruptible service at the election of the Customer.

RATE

The rates to be charged for this service shall be those negotiated between the Company and each Customer.

CONDITIONS

NSP service shall be provided subject to the provision of this pricing plan, the T-1 pricing plan, the T-2 pricing plan, or special gas supply agreements approved by the ACC, as applicable.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan CGS-1
Competitive Gas Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Applicable to natural gas use by customers that quality for service under this pricing plan according to either applicability Provision 1. or 2. below:

1. Customers whose annual requirements are greater than 10,000 therms and who in the Company's sole judgment have facilities capable of installing or using alternative fuels or energy to adequately serve their needs.

2. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales pricing plan. As a condition precedent to qualifying for service under this applicability provision, the customer must establish to the satisfaction of the Company, that bypass is economically, operationally, and physically feasible.

Any gas service rendered to customers not in conformance with the provisions of this pricing plan shall be billed at a rate equivalent to the otherwise applicable gas sales pricing plan.

RATE

The maximum service charge is the charge under the customer's otherwise applicable gas sales pricing plan.

Unless otherwise provided, the commodity charge per therm shall be determined in accordance with Condition No. 2 defined below. In no event shall the commodity charge per therm be less than the "floor" cost of gas, which is defined as the sum of (1) the weighted average commodity cost of gas purchased by the Company for system supply during the month, (2) the applicable upstream pipeline capacity charge, and (3) an amount to reflect distribution system shrinkage.

For customers qualifying for service, and if the Company is unable to serve such customer utilizing the "floor" cost of gas as set forth above, a Special Gas Procurement Agreement shall be executed and filed with the Arizona Corporation Commission ("ACC"), and the commodity charge per therm shall be determined in accordance with Condition No. 3 defined below.

With the exception of gas sales provided for under Condition No. 3, the Company shall account for sales under this pricing plan using the "floor" cost of purchased gas.

SUPPLIER REFUNDS

If, as a result of any final Order of the Federal Energy Regulatory Commission or the ACC that is no longer subject to judicial review, the Company receives a refund from any of its upstream pipeline transporters or suppliers which is applicable to gas sales made under this Competitive Gas Service Pricing Plan, the Company shall allocate such refund to its customers based on the therms billed during the refund period. The amount allocated to the customers served under this pricing plan shall be used to reduce such customer's gas costs.

CONDITIONS

1. Any qualified customer taking service under this pricing plan shall do so by agreement.

2. The commodity charge per therm may vary from customer to customer based on value of the service and on the customer's ability to change from one energy source to another, and may be revised from time to time as costs and conditions change. In no event shall the commodity charge per therm charged to the customer, excluding gross revenue taxes, exceed the commodity charge per therm that would have been charged under the customer's otherwise applicable gas sales pricing plan, adjusted to exclude any surcharge to amortize the balance in the Gas Cost Balancing Account.

3. A Special Gas Procurement Agreement under this pricing plan is defined herein as an agreement between the Company and an applicable customer, which enumerates the provisions whereby the Company will procure specific supplies of gas for the customer. The commodity charge per therm for Special Gas Procurement Agreement customers may vary depending on the terms and conditions of the Agreement, but in no event shall be less than the variable cost of gas procured from suppliers on behalf of the customer. A sole and separate accounting of gas purchases and sales made under Special Gas Procurement Agreements shall be maintained by the Company. The cost of gas purchases made for such customers will be excluded from the Purchased Gas Adjustment in Rider RR-1. However, the Company shall credit to Account No. 191, Unrecovered Purchased Gas Costs, all upstream pipeline capacity charges collected from the customer. (Note: Upstream pipeline capacity charges will be priced at market-based rates.)

4. All customers that qualify for service under this pricing plan because of alternate energy capability must be capable of installing adequate alternate energy facilities of equivalent capacity to those natural gas facilities served hereunder. These facilities are subject to Company inspection and verification of operating capacity and capability.

5. Any customer served under this pricing plan who returns to an otherwise applicable gas sales pricing plan shall be billed at the then currently effective pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSource Energy SERVICES

UNS Gas, Inc.
Pricing Plan CNG-1
Compressed Natural Gas Service
(Separately Metered)

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Service under this pricing plan is available to any customer where the customer purchases natural gas to be used as a motor fuel. Service will be separately metered. This rate may include compression by the Company beyond normal meter sales pressure.

RATE

Customer Charge: For customers using Compressed Natural Gas for only their own vehicle(s), the customer charge is that from the otherwise applicable pricing plan.

Basic Cost of Service Rates: The rate will be determined by a contract between the Company and the customer. In no case will the rate be lower than the Company's cost of gas, as determined by the most recent Purchased Gas Adjustment proceeding, nor will it be higher than one hundred fifty percent (150%) of the equivalent cost of premium gasoline.

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

CONDITIONS

1. This pricing plan does not include any road use fees or permits.
2. Customer must provide an affidavit to the Company certifying that the gas delivered will be used as motor fuel.
3. Compressor stations are subject to inspection by qualified Company personnel.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan EC-1
Electrical Cogeneration Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Service under this pricing plan is available to any customer who enters into a contract with the Company to use natural gas for the purpose of cogeneration. Cogeneration is defined as the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing, or other purposes.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105.00
Delivery Charge per therm @	$0.4488

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

CONDITIONS

1. Gas taken under this pricing plan shall be used exclusively for the purpose of cogeneration as defined in the Applicability section of this pricing plan and not for other purposes. The gas taken under this pricing plan will be separately metered.

2. This pricing plan will not be available for standby use.

3. For the purpose of this pricing plan, the annual load factor must be sixty percent (60%) or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve (12). If less than a sixty percent (60%) load factor occurs for a twelve (12) month period, the rate charged will be the rate that the customer would otherwise be served under for the months in which the annual load factor did not equal sixty percent (60%).

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan MISC-1
Miscellaneous Service Fees
(DELETE – ALL SERVICE FEES ARE LOCATED IN THE RULES AND REGULATIONS – SEE STATEMENT OF ADDITIONAL CHARGES

In addition to the Pricing Plans on file and approved by the Arizona Corporation Commission for natural gas service, the following fees are also approved for the respective services listed:

Service Transfer Fee	
Transfer of service from one customer to another, when meter is not turned off, per occurrence @	$15.00
Collection Fee	
When overdue payment is collected by a Company representative at the customer's premises, per occurrence @	$20.00
Special Call Out	
When a special call-out is required, the minimum charge shall be for one hour at the Company's then prevailing after hours rate for service work on the customer's premises.	
Establishment of Service	
During regular working hours, per occurrence @	$25.00
When performed outside of regular working hours, per occurrence @	$35.00
Re-establishment, Reconnection of Service for Non-Payment	
During regular working hours, per occurrence @	$45.00
When performed outside of regular working hours, occurrence @	$55.00
Re-establishment, Reconnection of Service for Other Reasons	
During regular working hours, per occurrence @	$35.00
When performed outside of regular working hours, per occurrence @	$45.00
Customer Requested Meter Re-Reads	
When reading is correct, per occurrence @	$15.00
Customer Requested Meter Test	
When meter tests are accurate within +/- 3%, per occurrence @	$65.00
Insufficient Funds Check (NSF)	
Insufficient funds, per occurrence @	$15.00
Multiple Attempts to Connect	
When more than one failed attempt to establish service due to customer not home or facilities not ready, per occurrence @	$15.00

Regular working hours are defined as non-holiday weekdays from 8:30 AM to 4:30 PM.

UniSource Energy SERVICES

UNS Gas, Inc.
Rider RR-1
Purchased Gas Adjustment (PGA)

APPLICABILITY
To all Company pricing plans, unless otherwise specified.

CHANGE IN RATE
UNS GAS Pricing Plans shall include a Cost of Natural Gas Charge ("CNGC") which recovers the cost of gas (natural, manufactured or in any approved form) purchased by UES on behalf of its customer. The cost of natural gas shall include all costs (demand, energy, customer-related and other) of the physical gas commodity and all costs assessed to facilitate transportation and delivery of gas on a firm basis and at an appropriate pressure (unless otherwise specified by tariff or contract) to UES, including but not limited to carrying and other costs not elsewhere recovered. Carrying cost applied to PGA bank balances will be subject to the 3-month LIBOR rate as published by the Federal Reserve, plus 1.0% to cover the additional margin that UNS Gas must pay for short-term borrowings. The CNGC consists of the Purchased Gas Adjustment ("PGA") rate and any surcharge or credit authorized by the The Arizona Corporation Commission ("ACC") for recovery or refund of previous gas costs. The CNGC shall be subject to increases or decreases by the amount of the PGA which is based on the rolling twelve (12) month average of actual purchased gas costs and sales. The ACC has banded the PGA change so that the new PGA calculated for the month cannot be more than $0.15 per therm different than the PGA rate in effect during any of the preceding twelve (12) months, unless authorized by the ACC.

BANK BALANCE
The Company shall maintain an account to assure that it will neither over nor under collect, except to the extent authorized, as a result of adjustment in rates determined under the operation of this pricing plan. Entries shall be made monthly to reflect the amounts paid to suppliers for gas as recorded in the Federal Energy Regulatory Commission series of accounts numbered 800 through 806, less the cost of such gas (adjusted volumes multiplied by the CNGC). Interest will be applied to over and under collected bank balances based on the three (3) month commercial financial paper rate for each month, contained in the Federal Reserve Statistical Release, H-15, or its successor publication.

MONTHLY INFORMATION FILINGS
Each month, the Company shall make a cost of gas information filing that shall include gas volumes and costs by supply source, supplier refunds, credits, billing adjustments, and lost and unaccounted for gas. Each filing shall include monthly sales revenues, volumes, and number of customers by class. The filing should also include historical summaries of actual twelve (12) month purchase gas volumes, costs and sales activity to support the computation of the monthly PGA rate, in the format required by Decision Nos. 61225 and 62994.

ADDITIONAL REQUIREMENTS
Notification to the ACC is required if the PGA bank balance exceeds an over collection of $10,000,000. The Company must file an application for an adjustment within forty-five (45) days of completing the monthly informational filing that illustrates the threshold has been exceeded or contact the ACC to discuss why a credit is not necessary at this time. If the PGA bank balance is under collected, the Company has the right to file an application with the ACC requesting a surcharge. The ACC, upon review, may authorize the balance to be amortized through the surcharge/credit as part of the CNGC for a specified

period. Lost and unaccounted for gas recovery is limited to the lesser of the actual costs incurred or up to five percent (5.00%) of total annual throughput.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

EXHIBIT

DBE-3

UNS GAS, INC.
TARIFFS

RED-LINED VERSION

FOR TEST YEAR SEPTEMBER 30, 2008

UniSource Energy SERVICES

UNS Gas, Inc.

Pricing Plan Summary

Pricing Plan	Pricing Plan Title	Therm Limits	Effective Date	Customer Charge	Charge per Therm (Excluding CNG)	ACC Decision
R-10	Residential Gas Service		XX/X/XX	$10.00	$0.3920	XXXXX
R-10	Residential Gas Service		XX/X/XX	$12.00	$0.3480	XXXXX
R-10	Residential Gas Service		XX/X/XX	$14.00	$0.3039	XXXXX
R-12	C.A.R.E.S. ($0.15 discount applicable for billing months of November - April)		XX/X/XX	$7.00	Summer $0.327000 Winter $0.177000	XXXXX
C-20	Small Volume Commercial Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.3168	XXXXX
C-22	Large Volume Commercial Service	> 120,000 therms	XX/X/XX	$105.00	$0.2054	XXXXX
I-30	Small Volume Industrial Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.2808	XXXXX
I-32	Large Volume Industrial Service	> 120,000 therms	XX/X/XX	$105.00	$0.1136	XXXXX
PA-40	Small Volume Public Authority Service	≤ 120,000 therms	XX/X/XX	$15.50	$0.3104	XXXXX
PA-42	Large Volume Public Authority Service	> 120,000 therms	XX/X/XX	$105.00	$0.1430	XXXXX
PA-44	Special Gas Light Service		XX/X/XX	Various		XXXXX
IR-60	Irrigation Service		XX/X/XX	$15.50	$0.3804	XXXXX
CGS-1	Competitive Gas Service	> 10,000 therms	XX/X/XX	Negotiated		XXXXX
CNG-1	Compressed Natural Gas Service		XX/X/XX	Various		XXXXX
EC-1	Electric Cogeneration Service		XX/X/XX	$105.00	$0.0488	XXXXX
MISC-1	Miscellaneous Service Fees		XX/X/XX	Various		XXXXX
NSP-1	Negotiated Sales Program		XX/X/XX	Negotiated		XXXXX
T-1	Transportation of Customer-Secured Natural Gas	> 120,000 therms	XX/X/XX	Otherwise applicable base rates less embedded gas costs		XXXXX
T-2	Transportation Service Using Dedicated Transmission Facilities	> 120,000 therms	XX/X/XX	See tariff for detail of applicable charges		XXXXX
RR-1	Purchased Gas Adjustment		XX/X/XX			XXXXX
RR-2	DSM Adjustor		12/1/07	N/A	$0.0025 per therm	Decision No. 70011

NOTE

All sales pricing plans above include a Cost of Natural Gas Charge (CNGC) which recovers the cost of natural gas purchased by UNSG on behalf of its customers.

The CNGC rate shall be subject to increases or decreases by the amount of the Purchased Gas Adjustment in accordance with the provisions of Rider RR-1

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-10
Residential Gas Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Subject to availability, at point of delivery, to residential gas service in individual residences and individually metered apartments when all service is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month as of mm-dd-yyyy @	$10.00~~8.50~~
Minimum Customer Charge per month as of mm-dd-yyyy @	$12.00
Minimum Customer Charge per month as of mm-dd-yyyy @	$14.00
Delivery Charge per therm as of mm-dd-yyyy -@——	$0.3920~~3270~~
Delivery Charge per therm as of mm-dd-yyyy @	$0.3480
Delivery Charge per therm as of mm-dd-yyyy @	$0.3039

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-12
Customer Assistance Residential Energy Support (C.A.R.E.S.)

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Subject to availability, at point of delivery, to residential gas service in individual residences and individually metered apartments when all service is metered through one meter.

~~To gas service qualifying for billing under Residential Pricing Plan R-10 where the customer also has qualified for Pricing Plan R-12 as specified in the Company's plan for administration. All provisions of Pricing Plan R-10 will apply except as modified herein.~~

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

~~The monthly bill shall be in accordance with Pricing Plan R-10 except:~~

Minimum Customer Charge per month @	$7.00
Delivery Charge per therm @	$0.3270

Delivery Charge: first 100 therms or less per month will be discounted by $0.1500 per therm for the billing months of November through April.

SPECIAL CONDITIONS

1. Eligibility requirements for C.A.R.E.S. are set forth on the Company's Application and Declaration of Eligibility for Low Income Ratepayer Assistance form. Customers who desire to qualify for this pricing plan must initially make application to the Company for qualification and must provide verification to the Company that the customer's household gross income does not exceed one hundred fifty percent (150%) of the federal poverty level. Qualified customers must have an approved application form on file with the Company. Subsequent to the initial certification, the residential customer seeking to retain eligibility for the C.A.R.E.S. must provide a personal certification that the household gross income of the residential dwelling unit involved does not exceed one hundred fifty percent (150%) of the federal poverty level.

2. Samples of the existing C.A.R.E.S. participants will be re-certified every two years prior to October 1 and when a customer changes residence.

3. Eligible customers shall be billed under this pricing plan during the winter season, commencing with the next regularly scheduled billing period after the Company has received the customer's properly completed application form or re-certification.

4. Eligibility information provided by the customer on the application form may be subject to verification by the Company. Refusal or failure of a customer to provide documentation of eligibility acceptable to the Company, upon request of the Company, shall result in removal from or ineligibility for this pricing plan.

5. Customers who wrongfully declare eligibility or fail to notify the Company when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential pricing plan.

6. It is the responsibility of the customer to notify the Company within thirty (30) days of any changes in the customer's eligibility status.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan C-20
Small Volume Commercial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all commercial customers whose primary business activity at the location served is not provided for under any other pricing plan, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery, and whose gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50~~3.50~~
Delivery Charge per therm @	$0.3168~~2638~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas ajustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan C-22
Large Volume Commercial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all commercial customers whose primary business activity at the location served is not provided for under any other pricing plan and whose preceding twelve (12) month usage exceeded 120,000 therms. Service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this schedule may not return for a period of twelve (12) billing periods.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105~~00~~.00
Delivery Charge per therm @	$0.2054~~1718~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan I-30
Small Volume Industrial Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
To all customers whose gas usage does not exceed 120,000 therms per year, who are served through a single meter, and whose primary business activity at the location served is included in one of the following classifications of the North American Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors;
Sector 22. Utilities: Power Generation Subsectors only; and
Sectors 31-33. Manufacturing: All Subsectors.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50~~3.50~~
Delivery Charge per therm @	$0.2808~~356~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan I-32
Large Volume Industrial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all customers whose gas usage over the preceding twelve (12) months exceeded 120,000 therms, and whose primary business activity at the location served is included in one of the following classifications of the North American Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors;
Sector 22. Utilities: Power Generation Subsectors only; and
Sectors 31-33. Manufacturing: All Subsectors.

Service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.
Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105~~0~~.00
Delivery Charge per therm @	$0.1136~~0952~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-40
Small Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery and gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50~~3.50~~
Delivery Charge per therm @	$0.3104~~2593~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-42
Large Volume Public Authority Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract. Under this pricing plan, usage over the preceding twelve (12) months must exceed 120,000 therms when all service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$105~~00~~.00
Delivery Charge per therm @	$0.1430~~198~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-44
Special Gas Light Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the facilities served.

APPLICABILITY
To all public authority customers for the operation by the Company of gas lights for streets in which gas distribution facilities are located.

RATE
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

Single Orifice @	$21.57~~3.72~~
Double Orifice @	$43.13~~39.53~~
Triple Orifice @	$64.70~~54.86~~
Quadruple Orifice @	$86.27~~71.16~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. -The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

~~Lake Havasu City~~

~~Lighting Group A per light per month @~~	~~$15.17~~
~~Lighting Group B per light per month @~~	~~$18.20~~

~~(Lighting Groups defined below)~~

CONDITIONS

~~1. The following definitions shall apply for Lake Havasu City Gas Lights:~~

~~a.Lighting Group A includes those 14 lights on McCullough Boulevard between Smoketree and Lake Havasu Avenue and those 62 lights in the Lake Havasu Mobile Trailer Parks;~~
~~b.Lighting Group B includes those 316 lights on the Country Club Golf Course;~~

~~PRICING PLAN PA-44 (continued)~~

21. Contracts for gas lighting service under this pricing plan must be for a minimum term of five (5) years.

2~~3~~. The cost of relocation of any gas light that is requested by the customer will be reimbursed to the Company by the customer.

3~~4~~. The customer is not authorized to make any connections to gas lines serving individual gas lights or make any alteration of such lights.

4~~5~~. The Company will use diligence in maintaining gas lighting service and monthly bills will not be reduced because of any gas light outage.

5~~6~~. Any special contracts for public authority lighting will be based on an analysis of costs of operation, maintenance, and investment. Any contracts pursuant to this pricing plan, which provide for higher rates than set forth in this pricing plan, will be filed with the Arizona Corporation Commission for approval.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan IR-60
Irrigation Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all irrigation customers whose primary business activity at the location served is not provided for under any other pricing plan, who operates one or more gas-fueled engines, and gas is metered through one meter.

The Company may require that gas for engine use be separately metered and billed if necessary to prevent abuse or inequity in the application of this rate.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$15.50~~3.50~~
Delivery Charge per therm @	$0.3804~~192~~

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan CGS-1
Competitive Gas Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
Applicable to natural gas use by customers that quality for service under this pricing plan according to either applicability Provision 1. or 2. below:

1. Customers whose annual requirements are greater than 10,000 therms and who in the Company's sole judgment have facilities capable of installing or using alternative fuels or energy to adequately serve their needs.

2. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales pricing plan. As a condition precedent to qualifying for service under this applicability provision, the customer must establish to the satisfaction of the Company, that bypass is economically, operationally, and physically feasible.

Any gas service rendered to customers not in conformance with the provisions of this pricing plan shall be billed at a rate equivalent to the otherwise applicable gas sales pricing plan.

RATE
The maximum service charge is the charge under the customer's otherwise applicable gas sales pricing plan.

Unless otherwise provided, the commodity charge per therm shall be determined in accordance with Condition No. 2 defined below. In no event shall the commodity charge per therm be less than the "floor" cost of gas, which is defined as the sum of (1) the weighted average commodity cost of gas purchased by the Company for system supply during the month, (2) the applicable upstream pipeline capacity charge, and (3) an amount to reflect distribution system shrinkage.

For customers qualifying for service, and if the Company is unable to serve such customer utilizing the "floor" cost of gas as set forth above, a Special Gas Procurement Agreement shall be executed and filed with the Arizona Corporation Commission ("ACC"), and the commodity charge per therm shall be determined in accordance with Condition No. 3 defined below.

With the exception of gas sales provided for under Condition No. 3, the Company shall account for sales under this pricing plan using the "floor" cost of purchased gas.

SUPPLIER REFUNDS
If, as a result of any final Order of the Federal Energy Regulatory Commission or the ACC that is no longer subject to judicial review, the Company receives a refund from any of its upstream pipeline transporters or suppliers which is applicable to gas sales made under this Competitive Gas Service Pricing Plan, the Company shall allocate such refund to its customers based on the therms billed during the refund period. The amount allocated to the customers served under this pricing plan shall be used to reduce such customer's gas costs.

CONDITIONS

1. Any qualified customer taking service under this pricing plan shall do so by agreement.

2. The commodity charge per therm may vary from customer to customer based on value of the service and on the customer's ability to change from one energy source to another, and may be revised from time to time as costs and conditions change. In no event shall the commodity charge per therm charged to the customer, excluding gross revenue taxes, exceed the commodity charge per therm that would have been charged under the customer's otherwise applicable gas sales pricing plan, adjusted to exclude any surcharge to amortize the balance in the Gas Cost Balancing Account.

3. A Special Gas Procurement Agreement under this pricing plan is defined herein as an agreement between the Company and an applicable customer, which enumerates the provisions whereby the Company will procure specific supplies of gas for the customer. The commodity charge per therm for Special Gas Procurement Agreement customers may vary depending on the terms and conditions of the Agreement, but in no event shall be less than the variable cost of gas procured from suppliers on behalf of the customer. A sole and separate accounting of gas purchases and sales made under Special Gas Procurement Agreements shall be maintained by the Company. The cost of gas purchases made for such customers will be excluded from the Purchased Gas Adjustment in Rider RR-1. However, the Company shall credit to Account No. 191, Unrecovered Purchased Gas Costs, all upstream pipeline capacity charges collected from the customer. (Note: Upstream pipeline capacity charges will be priced at market-based rates.)

4. All customers that qualify for service under this pricing plan because of alternate energy capability must be capable of installing adequate alternate energy facilities of equivalent capacity to those natural gas facilities served hereunder. These facilities are subject to Company inspection and verification of operating capacity and capability.

5. Any customer served under this pricing plan who returns to an otherwise applicable gas sales pricing plan shall be billed at the then currently effective pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan CNG-1
Compressed Natural Gas Service
(Separately Metered)

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Service under this pricing plan is available to any customer where the customer purchases natural gas to be used as a motor fuel. Service will be separately metered. This rate may include compression by the Company beyond normal meter sales pressure.

RATE

Customer Charge: For customers using Compressed Natural Gas for only their own vehicle(s), the customer charge is that from the otherwise applicable pricing plan. ~~For all others, it is $30.00 per meter per month.~~

Basic Cost of Service Rates: The rate will be determined by a contract between the Company and the customer. In no case will the rate be lower than the Company's cost of gas, as determined by the most recent Purchased Gas Adjustment proceeding, nor will it be higher than one hundred fifty percent (150%) of the equivalent cost of premium gasoline.

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

CONDITIONS

1. This pricing plan does not include any road use fees or permits.
2. Customer must provide an affidavit to the Company certifying that the gas delivered will be used as motor fuel.
3. Compressor stations are subject to inspection by qualified Company personnel.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan EC-1
Electrical Cogeneration Service

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
Service under this pricing plan is available to any customer who enters into a contract with the Company to use natural gas for the purpose of cogeneration. Cogeneration is defined as the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing, or other purposes.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$1050.00
Delivery Charge per therm @	$0.4488

Cost of Natural Gas Charge ("CNGC"): This charge recovers the cost of natural gas purchased by UES on behalf of its customer. The CNGC shall be subject to increases or decreases by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1.

CONDITIONS

1. Gas taken under this pricing plan shall be used exclusively for the purpose of cogeneration as defined in the Applicability section of this pricing plan and not for other purposes. The gas taken under this pricing plan will be separately metered.

2. This pricing plan will not be available for standby use.

3. For the purpose of this pricing plan, the annual load factor must be sixty percent (60%) or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve (12). If less than a sixty percent (60%) load factor occurs for a twelve (12) month period, the rate charged will be the rate that the customer would otherwise be served under for the months in which the annual load factor did not equal sixty percent (60%).

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan NSP-1
Negotiated Sales Program

AVAILABILITY
In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY
Available to all customers who receive service under the Company's T-1 pricing plan (Transportation of Customer-Secured Natural Gas), T-2 pricing plan (Transportation Service Using Dedicated Transmission Facilities), or special gas supply agreements approved by the Arizona Corporation Commission ("ACC") that meet the minimum transportation requirements under the T-1 or T-2 pricing plans.

Service under the Negotiated Sales Program ("NSP") will be the sale of natural gas to a transportation customer who has negotiated with the Company for the delivery of natural gas to the interconnection of the Company's distribution system and an upstream pipeline at the City Gate. NSP service will be interruptible service at the election of the Customer.

RATE
The rates to be charged for this service shall be those negotiated between the Company and each Customer.

CONDITIONS
NSP service shall be provided subject to the provision of this pricing plan, the T-1 pricing plan, the T-2 pricing plan, or special gas supply agreements approved by the ACC, as applicable.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan MISC-1
Miscellaneous Service Fees
(DELETE – ALL SERVICE FEES ARE LOCATED IN THE RULES AND REGULATIONS – SEE STATEMENT OF ADDITIONAL CHARGES

In addition to the Pricing Plans on file and approved by the Arizona Corporation Commission for natural gas service, the following fees are also approved for the respective services listed:

Service Transfer Fee	
Transfer of service from one customer to another, when meter is not turned off, per occurrence @	$15.00
Collection Fee	
When overdue payment is collected by a Company representative at the customer's premises, per occurrence @	$20.00
Special Call Out	
When a special call-out is required, the minimum charge shall be for one hour at the Company's then prevailing after hours rate for service work on the customer's premises.	
Establishment of Service	
During regular working hours, per occurrence @	$25.00
When performed outside of regular working hours, per occurrence @	$35.00
Re-establishment, Reconnection of Service for Non-Payment	
During regular working hours, per occurrence @	$45.00
When performed outside of regular working hours, occurrence @	$55.00
Re-establishment, Reconnection of Service for Other Reasons	
During regular working hours, per occurrence @	$35.00
When performed outside of regular working hours, per occurrence @	$45.00
Customer Requested Meter Re-Reads	
When reading is correct, per occurrence @	$15.00
Customer Requested Meter Test	
When meter tests are accurate within +/- 3%, per occurrence @	$65.00
Insufficient Funds Check (NSF)	
Insufficient funds, per occurrence @	$15.00
Multiple Attempts to Connect	
When more than one failed attempt to establish service due to customer not home or facilities not ready, per occurrence @	$15.00

Regular working hours are defined as non-holiday weekdays from 8:30 AM to 4:30 PM.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-1 Supplementary Information
Transportation of Customer-Secured Natural Gas

Transportation customers procure their own gas and UNS Gas, Inc. ("Company") transports it from the connection with the interstate pipeline (at the city gate) over the Company's pipeline system to the customer's facility. To qualify, customers must use a minimum of 120,000 therms per year.

The rates per therm for transportation service from the city gate to the customer's facility are as follows:

Large Volume Commercial	$0.2054~~1718~~ per therm
Large Volume Industrial	$0.1136~~0952~~ per therm
Large Volume Public Authority	$0.1430~~1198~~ per therm

Customers must also pay for the following items:

1. Charges for lost and unaccounted for gas in accordance with Pricing Plan T-1 (Transportation of Customer-Secured Natural Gas);
2. A minimum Customer Charge of $105~~0~~ per month;
3. Telemetering equipment and a telephone line; and
4. The costs for delivery of gas to the city gate.

AVAILABILITY

This pricing plan is available to any qualifying Customer for transportation of natural gas by the Company from existing interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's system throughout its certificated Arizona Gas Service Area under the following conditions:

1. The Company has available capacity to render the requested service without construction of any additional facilities, except as provided by ~~Section 8 of~~ this pricing plan under Facility Additions..

2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities, and for a term compatible with the service being requested from the Company.

3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User.

4. The Customer's gas to be transported is greater than 120,000 therms per year. A Customer receiving service from the Company at multiple locations may aggregate meters with annual consumption of no less than 50,000 therms per meter to qualify for this service provided that all meter locations are served under a single entity. In addition, the annual consumption of customers that are aggregated must be greater than 120,000 therms per year.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

   (c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan that requests service under a sales pricing plan is ineligible to return to transportation service for a period of not less than twelve (12) months.

RATES

A discount from the following rates may be offered at the sole discretion of the Company if such discount is in the best interest of the Company and its ratepayers. The maximum amount that the Customer shall pay the Company monthly will be the sum of the following charges:

Customer Charge per Month: $105~~0~~.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount equal to the applicable unit sales margin for each therm as set forth in the Customer's otherwise applicable sales pricing plan for each meter. This volume charge will cover the Company's Delivery Charge as specified in the currently effective gas sales pricing plan but not including the base cost of gas specified therein.

~~In no event will the minimum charge be less than that set forth in Section 4.1 below.~~

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas costs on a sales basis and gas costs on a purchase basis determined in the development of the currently effective, Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company, at its sole option, may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities ~~Section 7~~ of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under these pricing plans.

Minimun Charge: The minimum charge will be the Basic Customer Charge per Month plus $0.005 per therm.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

   (a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

   (b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

   (c) Term of Service:
      i. Date of service requested to commence;
      ii. Date service requested to terminate, if known; and
      iii. Minimum term for transportation service shall be twelve (12) months.

   (d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

OPERATING PROCEDURES

1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

   The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

   The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

3. Quantities: All quantities referred to under ~~in~~ Operating Procedures of this pricing plan ~~Section 6~~ shall be provided as dekatherms ("DTH") (one million British Thermal Units).

4. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

5. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

6. Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500~~0,000~~ therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified in Payment for Excess Quantities ~~Section 7~~ of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified in Payment for Excess Quantities ~~Section 7~~ are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

   Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described in Facility Additions of this pricing plan ~~Section 8~~ or provide daily meter reads each calendar day.

7. Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

8. Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

9. Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

   (a) Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

   (b) The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

   (c) Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth in Balacing described as part of Operating Procedures ~~Section 6.6~~ herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

(i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

(b) Negative Excess Imbalance

A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

(i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the aggregate negative imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein.~~Section 7.1.~~ For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the ~~S~~section Payment For Excess Quantities ~~7.1~~ above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures ~~by Section 6.6~~ hereof, nor shall the s~~S~~ection Payment For Excess Quantities ~~7.1~~ or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules and Regulations as approved from time to time by the Arizona Corporation Commission. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges, whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-1 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-1 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the Company's PGA bank, calculated as follows:

(a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Basic Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time to time;

(b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

(c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

3. If a Customer converts back to a pricing plan for gas sales service while the PGA Surcharge existing at the time of the switch to T-1 service is still in effect, such Surcharge will not be applicable to the Customer's billed usage for the period it remains in effect. However, any future PGA Surcharge that may be put into effect will be applicable to the Customer's billed usage.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

CONDITIONS

1. Transportation of Customer-owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan which would otherwise be available to such Customer.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-2
Transportation Service Using Dedicated Transmission Facilities

AVAILABILITY

This pricing plan is only available to any qualifying Customer for transportation of natural gas by the Company from dedicated interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's transmission system throughout its certificated Arizona Gas Service Area under the following conditions:

1. The Company has or will have available capacity to render the requested service utilizing facilities dedicated to the requirements of the Customer, except as provided under Facility Additions ~~by Section 8~~ hereof;

2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Company;

3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User;

4. The Customer's requirement for gas to be transported is greater than 1,000 therms per day or 120,000 therms per year; and

5. The Customer is not taking service through dedicated facilities under the provisions of a special contract approved by the Arizona Corporation Commission ("ACC").

6. The Customer is classified as a utility that produces electricity.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

(c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan is ineligible to obtain sales service without executing a special contract approved by the ACC.

RATES

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

Customer Charge per month: $105~~0~~.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount to fund the Company's low income rate program equal to the portion of the applicable unit sales margin for each therm included in rates as set forth in the Customer's otherwise applicable sales pricing plan for each meter.

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas cost on a sales basis and gas cost on a purchase basis determined in the development of the currently effective Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company at its sole option may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities ~~Section 7~~ of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under this pricing plan.

Reservation Charge: An annual charge to be billed in twelve (12) equal monthly installments equal to the fully allocated costs to provide the dedicated facilities necessary to serve the Customer as described more fully in Rates of this pricing plan~~Section 3.2 below~~.

Determined on the basis of a fully allocated cost study filed with and approved by the ACC in the context of a general rate case except when the request for service is non-coincident with a rate filing. In the latter case, the Reservation Charge will be computed by the Company including the following elements:

(a) Return and income taxes at the rate of return approved by the ACC in the Company's last general rate case computed on the basis of the installed costs of the dedicated facilities plus an allocation of other rate base items including, as appropriate: intangible, general and common plant investment, less any applicable accumulated depreciation and deferred taxes, an allowance for working capital and materials and supplies;

(b) Operations expense including all operating and maintenance expenses, depreciation and amortization expense, taxes other than income related to the dedicated facilities and allocated rate base;

(c) Allocated indirect expense including an appropriate portion of customer accounting, sales and information, and administrative and general expenses; and

(d) Any other allocated costs incurred either directly or indirectly to provide the requested service.

Special Surcharge: An annual charge to be computed on the basis of the twelve (12) months ending September of the prior year and billed beginning in January in equal monthly installments, computed as the sum of the following charges:

(a) The revenue requirements for any additional investments required to provide the service requested by Customer subsequent to the establishment of the currently effective Reservation Charge,

(b) Any non-recurring operating and maintenance expenses associated with the facilities dedicated to the Customer in the previous year, and

(c) Any extraordinary expenses incurred by the Company on behalf of the Customer not included in (a) or (b) above.

Minimum Charge: The minimum charge will be the sum of the Basic Customer Charge per Month, the monthly Reservation Charge and any monthly Special Surcharge.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

(a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point, and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

(c) Term of Service:
i. Date service requested to commence;
ii. Date service requested to terminate, if known; and
iii. Minimum term for transportation service shall be twelve (12) months.

(d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

2. Construction Requirements: In the event that the Customer's request for service requires the construction of additional transmission facilities not otherwise addressed in section Payment For Excess Quantities herof, ~~Section 7,~~ Extension of Lines, in the Company's current Rules and Regulations, the following additional provisions may apply:

(a) The Company may request an advance for engineering and design services based on the Company's estimate of the anticipated costs related to the requested dedicated facilities;

(b) Any advance for engineering and design will be refunded to the Customer on commencement of service;

(c) Actual engineering and design costs will be included in the dedicated facilities' costs and recovered as a part of the Reservation Charge;

(d) If the dedicated facilities are not placed in service for any reason, the Company may retain the advance;

(e) Prior to the initiation of construction of the dedicated facilities, the Company will provide an estimate of the total costs and resulting annual costs to Customer;

(f) The Company shall not be liable for any differences between actual construction costs and estimated costs;

(g) Customer may withdraw the request for service prior to initiation of construction; and

(h) The Customer may request that construction cease prior to completion. However, if the dedicated facilities are not completed or placed in service, the Customer is liable for service under the terms of this pricing plan as if the facilities had been completed, based on the total construction costs expended on behalf of the Customer.

OPERATING PROCEDURES

1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

   The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

3. The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

4. Quantities: All quantities referred to under Operating Procedures ~~in Section 6~~ shall be provided as dekatherms ("DTH") (one million British Thermal Units).

5. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

6. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

7. ~~(f)~~ Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to

vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500~~0,000~~ therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified under Payment For Excess Quantities~~in Section 7~~ of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified under Payment For Excess Quantities ~~in Section 7~~ are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

1. Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described under Facility Additions ~~in Section 8~~ or provide daily meter reads each calendar day.

2. ~~(g)~~ Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

3. ~~(h)~~ Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

4. ~~(i)~~ Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

~~(a)~~5. Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

~~(b)~~6. The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

~~(c)~~7. Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth under Balacing described as part of Operating Procedures ~~in Section 6.6~~ herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

(i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

(b) Negative Excess Imbalance

A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

(i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the

aggregate negative imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein. For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the section Payment For Excess Quantities above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures hereof, nor shall the section Payment For Excess Quantities or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules of Service as approved from time to time by the ACC. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges,

whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges, and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-2 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-2 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request or completion of any required facilities, whichever is later.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the PGA bank accumulated while served under the Company's sales pricing plan, calculated as follows:

   (a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the Customer's last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Base Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time-to-time;

   (b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

   (c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

CONDITIONS

1. Transportation of Customer owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan, which would otherwise be applicable to such Customer.

APPLICABILITY
To all Company pricing plans, unless otherwise specified.

CHANGE IN RATE
UNS GAS Pricing Plans shall include a Cost of Natural Gas Charge ("CNGC") which recovers the cost of gas (natural, manufactured or in any approved form) purchased by UES on behalf of its customer. The cost of natural gas shall include all costs (demand, energy, customer-related and other) of the physical gas commodity and all costs assessed to facilitate transportation and delivery of gas on a firm basis and at an appropriate pressure (unless otherwise specified by tariff or contract) to UES, including but not limited to carrying and other costs not elsewhere recovered. Carrying cost applied to PGA bank balances will be subject to the 3-month LIBOR rate as published by the Federal Reserve, plus 1.0% to cover the additional margin that UNS Gas must pay for short-term borrowings. The CNGC consists of the Purchased Gas Adjustment ("PGA") rate and any surcharge or credit authorized by the The Arizona Corporation Commission ("ACC") for recovery or refund of previous gas costs. The CNGC shall be subject to increases or decreases by the amount of the PGA which is based on the rolling twelve (12) month average of actual purchased gas costs and sales. The ACC has banded the PGA change so that the new PGA calculated for the month cannot be more than $0.15 per therm different than the PGA rate in effect during any of the preceding twelve (12) months, unless authorized by the ACC.

BANK BALANCE
The Company shall maintain an account to assure that it will neither over nor under collect, except to the extent authorized, as a result of adjustment in rates determined under the operation of this pricing plan. Entries shall be made monthly to reflect the amounts paid to suppliers for gas as recorded in the Federal Energy Regulatory Commission series of accounts numbered 800 through 806, less the cost of such gas (adjusted volumes multiplied by the CNGC). Interest will be applied to over and under collected bank balances based on the three (3) month commercial financial paper rate for each month, contained in the Federal Reserve Statistical Release, H-15, or its successor publication.

MONTHLY INFORMATION FILINGS
Each month, the Company shall make a cost of gas information filing that shall include gas volumes and costs by supply source, supplier refunds, credits, billing adjustments, and lost and unaccounted for gas. Each filing shall include monthly sales revenues, volumes, and number of customers by class. The filing should also include historical summaries of actual twelve (12) month purchase gas volumes, costs and sales activity to support the computation of the monthly PGA rate, in the format required by Decision Nos. 61225 and 62994.

ADDITIONAL REQUIREMENTS
Notification to the ACC is required if the PGA bank balance exceeds an over collection of $10,000,000. The Company must file an application for an adjustment within forty-five (45) days of completing the monthly informational filing that illustrates the threshold has been exceeded or contact the ACC to discuss why a credit is not necessary at this time. If the PGA bank balance is under collected, the Company has the right to file an application with the ACC requesting a surcharge. The ACC, upon review, may authorize the balance to be amortized through the surcharge/credit as part of the CNGC for a specified

period. Lost and unaccounted for gas recovery is limited to the lesser of the actual costs incurred or up to five percent (5.00%) of total annual throughput.

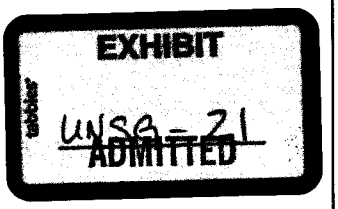
TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

July 8, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Gas, Inc. ("UNS Gas").

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

A. The purpose of my Rebuttal Testimony is to address Arizona Corporation Commission ("Commission") Staff's and the Residential Utility Consumer Office's ("RUCO") Direct Testimony on (i) the customer annualization adjustment, and (ii) UNS Gas' proposal for phased-in residential customer charge increases over a two-year period after rate implementation.

II. CUSTOMER ANNUALIZATION ADJUSTMENT.

Q. Please address the issue of the customer annualization adjustment.

A. UNS Gas proposed a customer annualization adjustment that follows the methodology approved in UNS Gas' last general rate case, Docket No. 04204A-06-0463, Decision No. 70011 (the "2006 Rate Case"). In both the 2006 Rate Case and this current, pending rate case, I refer to the methodology approved in Decision No. 70011 as "traditional."

Decision No. 70011 (at page 18-19) unambiguously expressed a preference for, and adopted, the traditional method of customer annualization adjustments.

In this proceeding, UNS Gas follows the approved "traditional" customer annualization methodology, while Staff and RUCO have deviated from this approved methodology.

Q. Please briefly describe the traditional customer annualization methodology.

A. Under this traditional approach, the monthly customer count for each of the first eleven months of the test-year is brought equal to the customer count in the twelfth and final month of the test-year (i.e., test-year-end). Assuming that the customer count grows by a positive amount each month, there will be a positive customer annualization adjustment for each month, and therefore a positive overall customer annualization adjustment. Customer counts for the first eleven months of the test-year would need to be adjusted upward (a positive adjustment) to bring them to the test-year-end level.

The purpose of the customer annualization adjustment is to recognize growth over the test-year. The customer count in the last (12th) month of the test-year is never adjusted because the last month is test-year-end. The count in the next-to-last (11th) month is adjusted for one month of growth, because the eleventh month is just one month removed from test-year-end. As one steps back in time toward the beginning of the test-year, the monthly counts are adjusted for progressively more months of growth. In this simple example, the monthly adjusted customer count (i.e., the actual customers plus the adjustment for each month) over the test-year is constant and unchanging.

UNS Gas' residential and commercial customer counts exhibit some seasonal variation. Customer counts dip in the summer, when some customers disconnect service with the intention of reconnecting in the late fall and winter. Test-year customer counts in the

2006 Rate Case exhibited seasonal variation similar to the variation in the current case. In the 2006 Rate Case, the Commission stated that there was a lack of significant seasonality, and no reason to deviate from the traditional method.[1] The Commission's stated position in favor of the traditional method motivated UNS Gas' use of this method.

Q. Are you concerned that Staff and RUCO witnesses have abandoned the use of the traditional customer annualization methodology?

A. Yes. Both Staff and RUCO witnesses strongly supported the traditional approach in the 2006 Rate Case. Staff's witness Mr. Ralph Smith (now RUCO's witness) testified that the "traditional method of customer annualization has been effective in appropriately coordinating the revenue element of the ratemaking formula with the other components, such as rate base."[2] Likewise, RUCO's witness, Ms. Marylee Diaz-Cortez, stated that UNS Gas does not experience "extreme seasonality" and that there is no "reason to depart from the "traditional" or Commission-accepted methodology of revenue annualization."[3]

Q. Please compare the impact of applying the traditional approach in this case, as compared to the 2006 Rate Case.

A. In the 2006 Rate Case, the traditional approach resulted in a less favorable result for UNS Gas (i.e., lower final rate levels), and the traditional approach was wholeheartedly supported by Staff and RUCO. By contrast, in this current case, the traditional approach results in a more favorable outcome for UNS Gas (i.e., higher final rate levels), however, Staff and RUCO now appear to have soured on the traditional approach.

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[1] Decision No. 70011 at page 19.
[2] Surrebuttal Testimony of Ralph C. Smith, Docket No. G-04204A-06-0463, page 21, lines 16-18.
[3] Surrebuttal Testimony of Marylee Diaz-Cortez, Docket No. G-04204A-06-0463, page 12, lines 20-23.

Q. What non-traditional methods did RUCO and Staff use?

A RUCO witness Mr. Smith proposes no customer annualization adjustment. RUCO's position is a rejection of the traditional approach, because under the traditional approach an adjustment should be made. Staff witness Dr. Thomas Fish proposes a very non-standard approach that is theoretically flawed and has an unwarranted positive bias that is detrimental to UNS Gas.

Q. How is Dr. Fish's customer annualization method flawed?

A. Dr. Fish's approach fails to meet the most basic goals of the customer annualization adjustment. Specifically it:

- adjusts customer counts to levels exceeding not only test-year-end, but all months of the test-year – and even months beyond the test-year (see Exhibit DBE-3 for customer counts);
- applies a future test-year approach to the customer annualization adjustment without applying future test-year methods to all other aspects of the ratemaking process – and thus violates the "matching principle";
- uses a significantly overstated and unsupportable customer count growth rate;
- fails to adjust customer count to test-year-end levels; and
- is not known and measurable because it uses customer levels that still have not been attained and will not be attained until some unknowable date in the future.

The impacts of these individual flaws compound to create a customer annualization adjustment far out of sync with the reality of UNS Gas' operations. From the perspective of accepted regulatory practice in Arizona, the matching principle is violated when a future test-year is used for customer annualization and then a historic test-year adjusted to test-year-end levels is used for other ratemaking purposes – which is exactly what Dr. Fish has done.

Q. How does Dr. Fish's approach violate the matching principle?

A. Customer annualization adjustments should restate customer counts to create a match in billing determinants, revenues and expenses. In the current case, Dr. Fish discards this matching principle by adjusting to a customer level that exceeds every monthly customer count – *whether before, during, or after the test-year* up to the date of filing this Rebuttal Testimony (July 8, 2009). Dr Fish's inflated customer count has not yet been achieved by July 8, 2009 and will not be achieved until some indeterminate time in the future. It cannot be described as "known and measurable" and it is inconsistent with the matching principle as well as Staff's testimony in the 2006 Rate Case. Dr. Fish's overstatement of the customer annualization adjustment is unjustified and contrary to accepted ratemaking practice in Arizona.

Q. What views has Staff expressed about matching in the past?

A. Staff often contends that matching is a core principle of ratemaking. For example, in the 2006 Rate Case, Staff's witness Mr. Smith stated that "It is very important to be consistent with a test period approach to ensure there is a consistent matching between investment, revenues and costs."[4] By using customer counts that will not be achieved until far after the test-year, Dr. Fish inflates revenue and disrupts matching. As Mr. Smith passionately argued at the Open Meeting for the 2006 Rate Case, "in the context of that historic test-year everything is in balance when revenues are annualized to the end of the test-year, and expenses are annualized to the end of the test-year and rate base is annualized to the end of the test-year."[5]

[4] Direct Testimony of Ralph C. Smith, Docket G-04204A-06-0463, page 5 lines 8-10.
[5] Open Meeting Transcript, November 8, 2007, page 112 lines 14-18.

Q. Has Staff expressed a specific view about considering new customers added after the test-year in the customer annualization adjustment?

A. Yes. In the 2006 Rate Case, Mr. Smith testified for Staff that "customers added after the test-year are not considered in the annualization adjustment."[6] Mr. Smith elaborated that "Customers that are added after the end of the test-year are typically not considered in an annualization adjustment, unless it is a major customer addition and the other elements of the ratemaking formula (rate base, depreciation, etc) have been appropriately synchronized."[7] There has been no "major customer addition" and Dr. Fish did not adjust the other elements of the ratemaking formula. Dr. Fish's use of customer counts far outside of the test-year – counts that still have not been actually reached – is impossible to square with Staff's customer annualization testimony in the 2006 Rate Case.

Q. Please illustrate how Dr. Fish has adjusted customer counts to overstated levels.

A. First, with respect to his adjustment to the regular residential rate, R-10, shown on Schedule THF-C-4 (page 1 of 8) of Dr. Fish's Direct Testimony, the R-10 customer count over the test-year (July 2007-June 2008) shows a minimum monthly count of 124,320 customers in August 2007, a maximum count of 126,799 customers in February 2008, and a test-year-end count of 124,957 in June 2008. Dr. Fish adjusts to a residential R-10 customer count of 128,112. This exceeds the maximum test-year residential R-10 monthly count by over 1%. As discussed below, more than a year after the close of the test-year, UNS Gas has not reached this inflated customer count and may not reach it for some significant time to come. Dr. Fish's residential customer count exceeds all pre-test-year counts as well as all counts occurring through July 8, 2009. While the 128,112 customer count may occur at some unknown future date, the Commission sets rates based on historic, not future, test-years and has repeatedly used the methodology followed by

[6] Surrebuttal Testimony of Ralph C. Smith, Docket No. G-04204A-06-0463, page 21, lines 25-26.
[7] Id. page 22, lines 2-5.

UNS Gas in this case. Dr. Fish's flawed annualization adjustment for R-10 makes up 70% of his total customer annualization adjustment.

Second, regarding Dr. Fish's adjustment to the small volume commercial rate, C-20, shown on Schedule THF-C-4 (page 2 of 8) of Dr. Fish's Direct Testimony, the C-20 customer count over the test-year (July 2007-June 2008) shows a minimum monthly count of 11,227 small commercial customers in August 2007, a maximum count of 11,614 customers in February 2008, and a test-year-end count of 11,384 in June 2008. Dr. Fish adjusts to a small commercial customer count of 11,702, which slightly exceeds even the maximum test-year count. The 11,702 customer count to which Dr. Fish adjusts is a level that exceeds all pre-test-year counts as well as all counts occurring through the date that this testimony is filed. Dr. Fish's flawed annualization adjustment for small volume commercial C-20 makes up 22% of his total customer annualization adjustment. Therefore, the flawed R-10 and C-20 customer annualization adjustments together make up 92% of Dr. Fish's customer annualization adjustment.

Q. How did Dr. Fish manage to overstate customer counts so significantly?

A. Dr. Fish did not follow the traditional customer annualization methodology used in the 2006 Rate Case. Dr. Fish inappropriately applied a potential estimated 2.5% growth rate referenced in UNS Gas witness David Hutchens' Direct Testimony to December 2007 class customer counts in a misguided attempt to create "normalized" future test-year-end values. Dr. Fish should never have pressed forward with his methodology, since he should have known the customer level to which he was adjusting had never occurred, nor would it occur, even over a period one year <u>after</u> the end of the test-year. The methodology also was simply unreasonable given the retraction in the economy almost immediately after the test-year and continuing to date. Even proponents of future test-

years might disagree with Dr. Fish's approach – effectively selecting adjustment targets more than one year after test-year-end.

Even if Dr. Fish's methodology were appropriate, Dr. Fish should have used an estimate of customer growth more suited to the typical, accepted methodology of customer annualization. For example, R-10 customer growth over the test-year showed an annualized growth rate of just 0.45%, less than one-fifth of Dr. Fish's 2.5% rate.

RUCO witness Mr. Smith's pre-filed Direct Testimony, at page 26, provides a measure of the post-test-year retraction in the economy of the service territory. Mr. Smith shows 12-month average residential customers growing by only 254 customers between June 2008 and March 2009, an annualized growth rate of just 0.26%, and just one-tenth of Dr. Fish's 2.5% rate. Likewise, statistical regression analysis shows no significant positive growth trend during or after the test-year.

Dr. Fish has compounded his error by applying the overstated growth rate inappropriately in his customer annualization calculation. Specifically, he has applied the growth rate to December 2007 customer counts. The December 2007 customer counts are close to the maximum counts experienced over the test-year. Dr. Fish ensures that his customer annualization adjustments will be inflated by the use of this methodology. He effectively treats all months of the test-year as if they are mid-winter, high customer count months. If past trends continue, the customer count will decline slightly in the summer. Dr. Fish ignores this fact, and inappropriately augments his annualization adjustment with a component attributable to seasonal variation, and not to a longer term growth trend.

Q. Is UNS Gas opposed to a future test-year approach?

A. No; UNS Gas would welcome a future test-year approach. However, it should not be done piecemeal as Dr. Fish proposes. Rather, it would entail a series of adjustments to normalize revenue and cost to some future period. The Commission would need to consider adjustments heretofore off-limits, including inflation adjustments and price elasticity adjustments. Additionally, future test-years would need to be used in a consistent manner, not simply for only certain adjustments. Moreover, as I have explained, even under a future test-year approach, Dr. Fish's adjustment would be extreme and likely not adopted because it is so far outside the test-year, because it is not certain when his proposed customer level will be reached, and because the "matching principle" has been violated by failing to coordinate the revenue element of the ratemaking formula with expenses, rate base, and other components affecting rates.

Q. Please discuss RUCO witness Mr. Smith's position on the customer annualization adjustment.

A. Mr. Smith takes issue with UNS Gas proposing a negative customer annualization adjustment for a system for which customer counts are not decreasing. Although at first glance, Mr. Smith's position may seem to have some appeal, it appears to be a more "heads I win, tails you lose" approach, particularly when compared with RUCO's position in the 2006 Rate Case. In 2006, RUCO's witness Ms. Diaz Cortez argued that the monthly customer counts did not show the type of seasonal variation to justify a deviation from the traditional approach. Mr. Ralph Smith, testifying for Staff in the 2006 Rate Case, argued that the traditional method has been effective in coordinating the revenue element of the ratemaking formula with other components such as rate base (the "matching principle"). In the last case, the traditional approach led to a less advantageous result for UNS Gas. Now that the traditional approach works to UNS Gas' benefit, Mr. Smith argues against "rote" application of the procedure.

UNS Gas strongly believes that equity dictates that the traditional approach – as the "accepted" approach - should apply in this case since it applied in the 2006 Rate Case which was adjudicated very recently.

Q. Explain why the consistency in customer annualization adjustment methodology is preferable to switching back and forth between various approaches.

A. One of the best arguments for consistency is that it promotes and supports the image of basic fairness in the treatment of various parties to the case. Moving back and forth between methodologies – looking for an end result of the lowest possible rates – does not result in just and reasonable rates, is inequitable and is not in the public interest.

Q. How does Dr. Fish attempt to justify deviating from the traditional approach?

A. Dr. Fish points to seasonal changes in UNS Gas' number of customers. UNS Gas experiences a slight drop in the number of customers in the summer, and Dr. Fish argues that this seasonality renders the traditional approach inappropriate for use in this case. However, UNS Gas' seasonality is essentially unchanged from the 2006 Rate Case, when the Commission noted a "lack of any significant demonstrated seasonality."[8] Moreover, the alleged seasonality problem raised by Dr. Fish typically occurs whenever an Arizona gas utility uses a test-year that ends in the summer.

Q. Are there other issues related to the customer annualization?

A. Yes. Staff's flawed customer annualization adjustment resulted in related flawed adjustments - fruits of the poisonous tree - to weather normalization and to rate case revenue annualization. Moreover, the flaws in Dr. Fish's rate case revenue annualization are compounded; the revenue annualization does not fully adjust test-year revenue for the rate change that occurred within the test-year. It appears that Dr. Fish's adjustment is

[8] Decision No. 70011 at page 19, line 5.

improperly limited to his overstated customer growth estimate. A rate case annualization adjustment should apply to all test-year sales – not just growth – billed prior to the "within-the-test-year" rate change. Therefore, Staff's adjustments to weather normalization and to rate case revenue annualization do not conform to accepted methodologies and should not be adopted.

III. CUSTOMER COUNTS SINCE THE END OF THE TEST YEAR.

Q. Do you have more recent data concerning customer counts?

A. Yes. Exhibit DBE-3 shows customer count data through May 2009. After the test-year (i.e., after June 2008), UNS Gas has experienced minimal to negative growth. Current (May 2009) residential (R-10) and small commercial (C-20) customer counts are below end of the test-year levels. Exhibit DBE-3 demonstrates that the customer counts used by Dr. Fish in his customer annualization adjustment are so significantly overstated that, even eleven months after the end of the test-year, UNS Gas' actual customer counts still fall well short of Dr. Fish's results. Additionally, Exhibit DBE-3 demonstrates that customer growth has slowed substantially in the test-year and in more recent months. As shown on pages 2 and 5 of Exhibit DBE-3, year-over-year customer growth is *negative* for eight out of eleven post test-year months. Thus, even if Dr. Fish's method is used, his growth factor is clearly excessive.

IV. PHASED-IN RESIDENTIAL CUSTOMER CHARGE INCREASES.

Q. Please summarize why UNS Gas is proposing to phase-in the residential customer charge increases over a two-year period.

A. My Direct Testimony focused on the need to recover more fixed costs through the fixed customer charge component. I proposed a phased-in increase for the (non-CARES)

residential customer charge, initially to $10.00 per month when new rates become effective subsequent to the conclusion of this rate case, followed by an increase to $12.00 per month one year after the initial rate implementation, followed by an increase to $14.00 per month two years after the initial rate implementation. UNS Gas' proposed residential customer charge increases are motivated by the Company's desire to (i) reduce its recovery of fixed costs through variable volumetric energy charges, and (ii) reduce the subsidization of customers in the warmer regions of UNS Gas' service territory by customers in cooler regions. Fixed costs are now collected disproportionately through variable energy (per therm) charges. UNS Gas' opportunity to recover fixed costs is jeopardized by the weather fluctuations and potentially by socially desirable energy efficiency and conservation. A more accurate alignment of revenue recovery and cost incursion helps align the goals of conservation with the Company's ability to earn a fair return on invested capital.

Q. Does Mr. Radigan acknowledge that the phased-in customer charge proposal is a movement in the direction of cost-based rates?

A. Yes. However, Mr. Radigan has concerns about the adverse impact on smaller residential customers. Customer charge increases result in larger percentage increases for smaller customers.

Q. Do you think that the potential for adverse impacts or "rate shock" is significant?

A. No; too much emphasis is placed on the percentage increase in the customer charge component. 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. Moreover, varying portions of the increase will be offset by lower non-fuel energy prices (per therm) – thus mitigating the customer charge increase. Again, for the sake of clarity, under the Company's proposal the customer

charge will only increase $1.50 per month in the first year, $2.00 per month in the second year and finally $2.00 per month in the third year.

UNS Gas' request is reasonable. The proposed increases are modest when considered in absolute dollar amounts. Further, any impact on our customers is ameliorated by the use of a phase-in structure. These increases do not result in "rate shock" and any "rate shock" reference is a distortion of the Company's proposal.

Q. Staff witness Dr. Fish states that the phased-in customer charge proposal is too complicated. Do you agree?

A. No, I do not. No rate design component is simpler than the customer charge. There is no basis for the idea that our customers are unable to understand a customer charge increase. Moreover, the Commission has ordered phased-in customer charges in other dockets.

Q. Dr. Fish states that even if the subsidy between warmer and cooler areas is eliminated, a new subsidy could arise.

A. Dr. Fish does not identify the nature of this potential subsidy. Our proposal is to reduce the current subsidy, not eliminate it, and certainly not to create a new, different subsidy.

Q. Dr. Fish supports his arguments with his "Customer Class Risk" analysis. What is your opinion of this study?

A. Dr. Fish uses his statistical analysis – based on coefficients of variation – to argue that the risk to the Company from sales variations is of no consequence. Dr. Fish may be surprised to learn how leveraged UNS Gas's earnings are to volumetric (therm) sales, and how a seemingly small reduction in volumetric sales can greatly reduce UNS Gas' earnings. For example, a reduction in therms sold of just 3% can lead to a pre-tax earnings reduction of

over $1,000,000 per year. Dr. Fish's analysis contains no usable sensitivity analysis, and as presented, only serves to obscure the degree of financial risk this Company faces.

V. EXEMPTION OF CARES CUSTOMERS FROM DSM SURCHARGE.

Q. Please discuss the exemption of UNS Gas' CARES customers from the Demand-Side Management (DSM) surcharge.

A. On March 24, 2009, UNS Gas filed an application for Commission approval to reset the Company's DSM adjustor rate, in accordance with Decision No. 70011. On June 5, 2009, the Commission issued Decision No. 71105 approving a $0.0050 per therm increase in the adjustor rate, increasing the surcharge from $0.0026 per therm (approved May 27, 2008 in Decision No. 70011) to $0.0076 per therm. To protect UNS Gas' CARES customers from an increase in their bills, the Commission ordered that customers enrolled in CARES should not be charged the entire DSM rate. Decision No. 71105 advised UNS Gas to track surcharges that otherwise would have been collected from customers in CARES, absent the CARES exemption. Decision No. 71105 precluded an immediate increase in the DSM surcharge (from the $0.0076 per therm level) to account for the recovery shortfall associated with the exemption of the CARES program's therms. The order advised that unrecovered surcharges would be dealt with in the current pending rate case. UNS Gas plans to include the unrecovered surcharges in its DSM filing to be made on or before April 1, 2010, in accordance with the current approved practice for DSM recoveries. In the 2010 DSM filing, the proposed DSM adjustor rate will reflect the exemption of the CARES program customers from the DSM surcharge.

The bill impacts of exempting CARES customers from the DSM surcharge are shown on Exhibit DBE-4. This exhibit shows that CARES customers using over 10 therms per month save at least 0.4% on monthly bills, assuming the Company-proposed rate levels.

Over 78% of bills have monthly usage greater than or equal to 10 therms. Exempting CARES customers from the DSM surcharge results in cost recovery being shifted away from CARES customers and onto other retail customers. The impact of this shift in cost recovery on an average non-CARES residential customer will be less than $1.00 per year.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT

DBE-3

UNS Gas, Inc.
Test-Year Ending June 30, 2008

Rate R-10 Customer Count
Customer Count Growth Measures (August 2003-May 2009)

Month	Monthly Customer Count	12 Month Moving Average	% Monthly Change in Moving Average	Monthly Change On Annualized Basis	Year-Over-Year Change
August-03	112,280	-----	-----	-----	-----
September-03	112,347	-----	-----	-----	-----
October-03	113,807	-----	-----	-----	-----
November-03	114,975	-----	-----	-----	-----
December-03	114,402	-----	-----	-----	-----
January-04	115,000	-----	-----	-----	-----
February-04	114,331	-----	-----	-----	-----
March-04	115,254	-----	-----	-----	-----
April-04	115,491	-----	-----	-----	-----
May-04	115,241	-----	-----	-----	-----
June-04	115,969	-----	-----	-----	-----
July-04	115,533	114,553	-----	-----	-----
August-04	116,003	114,863	0.3%	3.3%	3.3%
September-04	115,949	115,163	0.3%	3.2%	3.2%
October-04	115,763	115,326	0.1%	1.7%	1.7%
November-04	116,776	115,476	0.1%	1.6%	1.6%
December-04	117,256	115,714	0.2%	2.5%	2.5%
January-05	117,850	115,951	0.2%	2.5%	2.5%
February-05	117,950	116,253	0.3%	3.2%	3.2%
March-05	118,857	116,553	0.3%	3.1%	3.1%
April-05	118,520	116,806	0.2%	2.6%	2.6%
May-05	118,414	117,070	0.2%	2.8%	2.8%
June-05	118,917	117,316	0.2%	2.5%	2.5%
July-05	118,669	117,577	0.2%	2.7%	2.7%
August-05	119,326	117,854	0.2%	2.9%	2.9%
September-05	119,352	118,138	0.2%	2.9%	2.9%
October-05	120,088	118,498	0.3%	3.7%	3.7%
November-05	120,644	118,820	0.3%	3.3%	3.3%
December-05	121,483	119,173	0.3%	3.6%	3.6%
January-06	122,261	119,540	0.3%	3.8%	3.7%
February-06	122,562	119,924	0.3%	3.9%	3.9%
March-06	122,791	120,252	0.3%	3.3%	3.3%
April-06	122,689	120,600	0.3%	3.5%	3.5%
May-06	122,317	120,925	0.3%	3.3%	3.3%
June-06	122,404	121,216	0.2%	2.9%	2.9%
July-06	122,520	121,536	0.3%	3.2%	3.2%
August-06	123,022	121,844	0.3%	3.1%	3.1%
September-06	123,526	122,192	0.3%	3.5%	3.5%
October-06	124,204	122,535	0.3%	3.4%	3.4%
November-06	124,828	122,884	0.3%	3.5%	3.5%
December-06	125,383	123,209	0.3%	3.2%	3.2%
January-07	125,429	123,473	0.2%	2.6%	2.6%
February-07	125,495	123,717	0.2%	2.4%	2.4%
March-07	125,310	123,927	0.2%	2.1%	2.1%
April-07	125,010	124,121	0.2%	1.9%	1.9%
May-07	125,035	124,347	0.2%	2.2%	2.2%
June-07	124,841	124,550	0.2%	2.0%	2.0%

Rate R-10 Customer Count
Customer Count Growth Measures (August 2003-May 2009)

Month	Monthly Customer Count	12 Month Moving Average	% Monthly Change in Moving Average	Monthly Change On Annualized Basis	Year-Over-Year Change	
July-07	**124,445**	**124,711**	**0.1%**	**1.6%**	**1.6%**	**Test Year Month 1**
August-07	**124,320**	**124,819**	**0.1%**	**1.0%**	**1.1%**	**Test Year Month 2**
September-07	**124,871**	**124,931**	**0.1%**	**1.1%**	**1.1%**	**Test Year Month 3**
October-07	**125,497**	**125,039**	**0.1%**	**1.0%**	**1.0%**	**Test Year Month 4**
November-07	**125,973**	**125,134**	**0.1%**	**0.9%**	**0.9%**	**Test Year Month 5**
December-07	**126,530**	**125,230**	**0.1%**	**0.9%**	**0.9%**	**Test Year Month 6**
January-08	**126,782**	**125,342**	**0.1%**	**1.1%**	**1.1%**	**Test Year Month 7**
February-08	**126,799**	**125,451**	**0.1%**	**1.0%**	**1.0%**	**Test Year Month 8**
March-08	**126,239**	**125,529**	**0.1%**	**0.7%**	**0.7%**	**Test Year Month 9**
April-08	**125,566**	**125,575**	**0.0%**	**0.4%**	**0.4%**	**Test Year Month 10**
May-08	**125,216**	**125,590**	**0.0%**	**0.1%**	**0.1%**	**Test Year Month 11**
June-08	**124,957**	**125,600**	**0.0%**	**0.1%**	**0.1%**	**Test Year Month 12**
July-08	124,790	125,628	0.0%	0.3%	0.3%	
August-08	124,856	125,673	0.0%	0.4%	0.4%	
September-08	124,712	125,660	0.0%	-0.1%	-0.1%	Year-over-year contraction.
October-08	123,985	125,534	-0.1%	-1.2%	-1.2%	Year-over-year contraction.
November-08	126,380	125,568	0.0%	0.3%	0.3%	
December-08	125,522	125,484	-0.1%	-0.8%	-0.8%	Year-over-year contraction.
January-09	125,136	125,347	-0.1%	-1.3%	-1.3%	Year-over-year contraction.
February-09	126,134	125,291	0.0%	-0.5%	-0.5%	Year-over-year contraction.
March-09	125,128	125,199	-0.1%	-0.9%	-0.9%	Year-over-year contraction.
April-09	124,681	125,125	-0.1%	-0.7%	-0.7%	Year-over-year contraction.
May-09	124,293	125,048	-0.1%	-0.7%	-0.7%	Year-over-year contraction.

In months following the test year, there were year-over-year contractions in 8 out of 11 months --
NOT SIGNS OF A RAPIDLY GROWING SYSTEM.

Rate R-10 Customer Count
Customer Count Growth Measures

Month	Aug-03 through Jun-04	Jul-04 through Jun-05	Jul-05 through Jun-06	Jul-06 through Jun-07	Test Year Jul-07 through Jun-08	Jul-08 through May-09	Month
Jul		115,533	118,669	122,520	**124,445**	124,790	Jul
Aug	112,280	116,003	119,326	123,022	124,320	124,856	Aug
Sep	112,347	115,949	119,352	123,526	124,871	124,712	Sep
Oct	113,807	115,763	120,088	124,204	125,497	123,985	Oct
Nov	114,975	116,776	120,644	124,828	125,973	126,380	Nov
Dec	114,402	117,256	121,483	125,383	126,530	125,522	Dec
Jan	115,000	117,850	122,261	125,429	126,782	125,136	Jan
Feb	114,331	117,950	122,562	125,495	126,799	126,134	Feb
Mar	115,254	118,857	122,791	125,310	126,239	125,128	Mar
Apr	115,491	118,520	122,689	125,010	125,566	124,681	Apr
May	115,241	118,414	122,317	125,035	125,216	124,293	May
Jun	115,969	118,917	122,404	**124,841**	**124,957**		Jun

Dr. Fish adjusts to: **128,112 R-10 Customers - A level never reached.**

Annualized Test-Year Growth (1st measure): 0.45% (Based on Jul07 (beginning) and Jun08 (end)) (124957/124445)^(12/11)-1

Annualized Test-Year Growth (2nd measure): 0.09% (Based on Jun07 (beginning) and Jun08 (end)) (124957/124841)-1

UNS Gas, Inc.
Test-Year Ending June 30, 2008

Rate R-20 Customer Count
Customer Count Growth Measures (August 2003-May 2009)

Month	Monthly Customer Count	12 Month Moving Average	% Monthly Change in Moving Average	Monthly Change On Annualized Basis	Year-Over-Year Change
August-03	10,219	-----	-----	-----	-----
September-03	10,198	-----	-----	-----	-----
October-03	10,208	-----	-----	-----	-----
November-03	10,404	-----	-----	-----	-----
December-03	10,511	-----	-----	-----	-----
January-04	10,699	-----	-----	-----	-----
February-04	10,687	-----	-----	-----	-----
March-04	10,747	-----	-----	-----	-----
April-04	10,788	-----	-----	-----	-----
May-04	10,680	-----	-----	-----	-----
June-04	10,647	-----	-----	-----	-----
July-04	10,532	10,527	-----	-----	-----
August-04	10,471	10,548	0.2%	2.4%	2.5%
September-04	10,449	10,569	0.2%	2.4%	2.5%
October-04	10,464	10,590	0.2%	2.4%	2.5%
November-04	10,711	10,616	0.2%	2.9%	3.0%
December-04	10,866	10,645	0.3%	3.4%	3.4%
January-05	10,901	10,662	0.2%	1.9%	1.9%
February-05	10,915	10,681	0.2%	2.2%	2.1%
March-05	10,998	10,702	0.2%	2.4%	2.3%
April-05	10,984	10,718	0.2%	1.8%	1.8%
May-05	10,926	10,739	0.2%	2.3%	2.3%
June-05	10,840	10,755	0.1%	1.8%	1.8%
July-05	10,796	10,777	0.2%	2.5%	2.5%
August-05	10,754	10,800	0.2%	2.7%	2.7%
September-05	10,724	10,823	0.2%	2.6%	2.6%
October-05	10,752	10,847	0.2%	2.7%	2.8%
November-05	10,845	10,858	0.1%	1.2%	1.3%
December-05	11,041	10,873	0.1%	1.6%	1.6%
January-06	11,159	10,895	0.2%	2.4%	2.4%
February-06	11,193	10,918	0.2%	2.6%	2.5%
March-06	11,201	10,935	0.2%	1.9%	1.8%
April-06	11,163	10,950	0.1%	1.6%	1.6%
May-06	11,068	10,961	0.1%	1.3%	1.3%
June-06	11,015	10,976	0.1%	1.6%	1.6%
July-06	11,000	10,993	0.2%	1.9%	1.9%
August-06	10,987	11,012	0.2%	2.1%	2.2%
September-06	11,035	11,038	0.2%	2.9%	2.9%
October-06	11,159	11,072	0.3%	3.8%	3.8%
November-06	11,288	11,109	0.3%	4.1%	4.1%
December-06	11,435	11,142	0.3%	3.6%	3.6%
January-07	11,477	11,168	0.2%	2.9%	2.8%
February-07	11,479	11,192	0.2%	2.6%	2.6%
March-07	11,444	11,213	0.2%	2.2%	2.2%
April-07	11,385	11,231	0.2%	2.0%	2.0%
May-07	11,337	11,253	0.2%	2.4%	2.4%
June-07	11,302	11,277	0.2%	2.6%	2.6%

Rate R-20 Customer Count
Customer Count Growth Measures (August 2003-May 2009)

Month	Monthly Customer Count	12 Month Moving Average	% Monthly Change in Moving Average	Monthly Change On Annualized Basis	Year-Over-Year Change	
July-07	11,267	**11,300**	**0.2%**	**2.4%**	**2.4%**	**Test Year Month 1**
August-07	11,227	**11,320**	**0.2%**	**2.1%**	**2.2%**	**Test Year Month 2**
September-07	11,232	**11,336**	**0.1%**	**1.8%**	**1.8%**	**Test Year Month 3**
October-07	11,306	**11,348**	**0.1%**	**1.3%**	**1.3%**	**Test Year Month 4**
November-07	11,404	**11,358**	**0.1%**	**1.0%**	**1.0%**	**Test Year Month 5**
December-07	11,558	**11,368**	**0.1%**	**1.1%**	**1.1%**	**Test Year Month 6**
January-08	11,606	**11,379**	**0.1%**	**1.1%**	**1.1%**	**Test Year Month 7**
February-08	11,614	**11,390**	**0.1%**	**1.2%**	**1.2%**	**Test Year Month 8**
March-08	11,570	**11,401**	**0.1%**	**1.1%**	**1.1%**	**Test Year Month 9**
April-08	11,482	**11,409**	**0.1%**	**0.9%**	**0.9%**	**Test Year Month 10**
May-08	11,420	**11,416**	**0.1%**	**0.7%**	**0.7%**	**Test Year Month 11**
June-08	11,384	**11,423**	**0.1%**	**0.7%**	**0.7%**	**Test Year Month 12**
July-08	11,327	11,428	0.0%	0.5%	0.5%	
August-08	11,284	11,432	0.0%	0.5%	0.5%	
September-08	11,211	11,431	0.0%	-0.2%	-0.2%	Year-over-year contraction.
October-08	11,299	11,430	0.0%	-0.1%	-0.1%	Year-over-year contraction.
November-08	11,422	11,431	0.0%	0.2%	0.2%	
December-08	11,505	11,427	0.0%	-0.5%	-0.5%	Year-over-year contraction.
January-09	11,501	11,418	-0.1%	-0.9%	-0.9%	Year-over-year contraction.
February-09	11,536	11,412	-0.1%	-0.7%	-0.7%	Year-over-year contraction.
March-09	11,477	11,404	-0.1%	-0.8%	-0.8%	Year-over-year contraction.
April-09	11,416	11,399	0.0%	-0.6%	-0.6%	Year-over-year contraction.
May-09	11,354	11,393	0.0%	-0.6%	-0.6%	Year-over-year contraction.

In months following the test year, there were year-over-year contractions in 8 out of 11 months --
NOT SIGNS OF A RAPIDLY GROWING SYSTEM.

Rate R-20 Customer Count
Customer Count Growth Measures

Month	Aug-03 through Jun-04	Jul-04 through Jun-05	Jul-05 through Jun-06	Jul-06 through Jun-07	Test Year Jul-07 through Jun-08	Jul-08 through May-09	Month
Jul		10,532	10,796	11,000	**11,267**	11,327	Jul
Aug	10,219	10,471	10,754	10,987	11,227	11,284	Aug
Sep	10,198	10,449	10,724	11,035	11,232	11,211	Sep
Oct	10,208	10,464	10,752	11,159	11,306	11,299	Oct
Nov	10,404	10,711	10,845	11,288	11,404	11,422	Nov
Dec	10,511	10,866	11,041	11,435	11,558	11,505	Dec
Jan	10,699	10,901	11,159	11,477	11,606	11,501	Jan
Feb	10,687	10,915	11,193	11,479	11,614	11,536	Feb
Mar	10,747	10,998	11,201	11,444	11,570	11,477	Mar
Apr	10,788	10,984	11,163	11,385	11,482	11,416	Apr
May	10,680	10,926	11,068	11,337	11,420	11,354	May
Jun	10,647	10,840	11,015	**11,302**	**11,384**		Jun

Dr. Fish adjusts to:	**11,702**	**R-20 Customers - A level never reached.**
Annualized Test-Year Growth (1st measure)	1.13%	(Based on Jul07 (beginning) and Jun08 (end)) (11384/11267)^(12/11)-1
Annualized Test-Year Growth (2nd measure)	0.73%	(Based on Jun07 (beginning) and Jun08 (end)) (11384/11302)-1

EXHIBIT

DBE-4

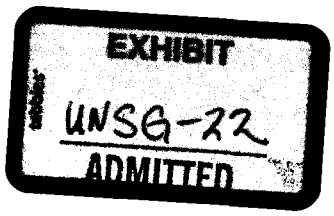
IMPACT OF EXEMPTING CARES FROM DSM SURCHARGE (WINTER MONTH)

ASSUMES UNS GAS PROPOSED RATES

Therms	% Bills with Lower Usage	MONTHLY BILL WITH DSM	MONTHLY BILL NO DSM	SAVINGS	PERCENT SAVINGS
0	0.0%	$7.00	$7.00	$0.00	0.0%
5	10.9%	$11.93	$11.89	$0.04	0.3%
10	21.9%	$16.86	$16.79	$0.08	0.5%
20	41.2%	$26.73	$26.58	$0.15	0.6%
30	53.1%	$36.59	$36.36	$0.23	0.6%
40	60.6%	$46.46	$46.15	$0.30	0.7%
50	66.4%	$56.32	$55.94	$0.38	0.7%
60	71.4%	$66.18	$65.73	$0.46	0.7%
70	75.9%	$76.05	$75.52	$0.53	0.7%
80	79.9%	$85.91	$85.30	$0.61	0.7%
90	83.4%	$95.78	$95.09	$0.68	0.7%
100	86.4%	$105.64	$104.88	$0.76	0.7%
110	88.9%	$117.00	$116.17	$0.84	0.7%
120	90.9%	$128.37	$127.46	$0.91	0.7%
130	92.7%	$139.73	$138.74	$0.99	0.7%
140	94.0%	$151.10	$150.03	$1.06	0.7%
150	95.2%	$162.46	$161.32	$1.14	0.7%
160	96.1%	$173.82	$172.61	$1.22	0.7%
170	96.8%	$185.19	$183.90	$1.29	0.7%
180	97.4%	$196.55	$195.18	$1.37	0.7%
190	97.8%	$207.92	$206.47	$1.44	0.7%
200	98.2%	$219.28	$217.76	$1.52	0.7%
300	99.6%	$332.92	$330.64	$2.28	0.7%
400	99.9%	$446.56	$443.52	$3.04	0.7%
500	99.9%	$560.20	$556.40	$3.80	0.7%
1,000	100.0%	$1,128.40	$1,120.80	$7.60	0.7%
2,500	100.0%	$2,833.00	$2,814.00	$19.00	0.7%
3,500	100.0%	$3,969.40	$3,942.80	$26.60	0.7%

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
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 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

Rejoinder Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

August 5, 2009

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I. Introduction 1

II. Customer Annualization Adjustment 1

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Did you file Direct and Rebuttal Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc.

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

A. The purpose of my Rejoinder Testimony is to address the Arizona Corporation Commission ("Commission") Staff's and the Residential Utility Consumer Office's ("RUCO") Rebuttal Testimony on (i) the customer annualization adjustment, and (ii) UNS Gas' proposal for phased-in residential customer charge increases over a two-year period after rate implementation.

II. CUSTOMER ANNUALIZATION ADJUSTMENT.

Q. Please summarize RUCO's concern about the Company's proposed customer annualization adjustment.

A. RUCO witness Ralph C. Smith states that it does not make sense to reduce test-year revenue when UNS Gas has continued to experience year-over-year customer growth.

Q. Do you agree with Mr. Smith's contention?

A. Not at all. This result is an expected consequence of the application of the traditional approach to customer annualization. And it is not just expected; the result is entirely appropriate, in the public interest, and necessary to ensure equitable and consistent treatment of the parties to this proceeding.

Q. Please explain.

A. UNS Gas has in this proceeding proposed the exact methodology approved the Commission and supported by Staff and RUCO in the 2006 Case. This methodology is well-established in Arizona and elsewhere. I have been calculating customer annualization adjustments using this simple method since early 1982 when I was employed by the Public Utility Commission of Texas.

Under the traditional approach to customer annualization, customer counts are adjusted to test-year-end levels. The traditional approach is simple, and does not attempt to remove the effects of seasonality. Mr. Smith states the obvious with his observation that "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." (Smith Surrebuttal, page 38, lines 8-11.) Since UNS Gas adds seasonal customers in the winter and loses them in the summer, the traditional method of customer annualization yields relatively larger customer annualization adjustments (that tend to lower rates) for winter-ending test years and relatively smaller customer annualization adjustments (that tend to increase rates) for summer ending test-years – as we had in this proceeding (test year ended June 30, 2008) – as compared to approaches that remove the effects of seasonality. The application of the traditional approach to customer count data for the test-year ended June 30, 2008 – data that exhibits both seasonality and an

insignificant underlying growth rate - results in a negative customer annualization in this case.

Equity dictates that these customer annualization results be compared to the results of the 2006 Rate Case, which had a winter-ending test-year (December 31, 2005). In the 2006 Rate Case, use of the traditional approach resulted in larger customer annualization adjustment (which resulted in lower rates) than would an adjustment based on an approach removing seasonality. Because of seasonality, actual December customer counts – which are the basis for the customer annualization adjustment – were relatively high because of the presence of seasonal customers. Neither Staff nor RUCO witnesses were concerned about seasonality in the 2006 Case when seasonality reduced UNS Gas' rate increase. In fact, Mr. Smith, then a Staff witness, argued in favor of the use of the traditional approach because it is straight-forward and transparent.[1] RUCO's witness in the 2006 Case, Marylee Diaz-Cortez, claimed that the seasonality was not extreme enough to "depart from the 'traditional' or **Commission-accepted** (*emphasis added)* methodology of revenue annualization."[2]

RUCO – and Staff -- seem determined to oppose the use of the traditional approach when it does not reduce rates. It is unfortunate that Staff and RUCO are permitting the final result – whether rates are increased or reduced – to determine their choice of customer annualization methodology. However, sometimes the traditional and accepted customer annualization approach results in smaller customer annualization adjustments and sometimes it results in larger customer annualization adjustments – as compared to alternate methods adjusting for seasonality. So sometimes application of the traditional

[1] 2006 Case, Smith Surrebuttal, page 20, lines 15-22.
[2] See Diaz-Cortez Surrebuttal, Docket No. G-04204A-06-0463, page 12, lines 20-23, see also Decision No. 70011 (November 27, 2007) at page 18, lines 18-20.

adjustment increases rates, and sometimes it decreases rates. This is an equitable result. Over time, things balance out if the traditional approach is used consistently.

Q. Why did you not in this case propose an alternate customer annualization?

A. In the 2006 Case, I did propose such an approach. However, the approach was opposed by both Staff and RUCO, and the Commission opted to maintain the traditional approach in Decision No. 70011. I accepted that the Commission preferred the traditional approach over my proposed approach; therefore, I used the traditional approach in this pending case. The use of the traditional approach in this pending case is consistent with Decision No. 70011, as well as numerous previous gas rate cases in Arizona.

Q. Mr. Smith criticizes your "rote" application of the traditional approach in this pending case. (Smith Surrebuttal, page 38, lines 6-8). Please comment.

A. For Mr. Smith, avoidance of "rote application" seems to be code for a "heads I win, tails you lose" approach that is biased against UNS Gas. Moving back and forth between methodologies – looking for an end result of the lowest possible rates – does not result in just and reasonable rates, is inequitable and is not in the public interest.

Q. In the prior UNS Gas rate case, you proposed an annualization approach that made an adjustment to address seasonality. Why are you opposed to Staff witness Dr. Thomas Fish's customer annualization approach, which also attempts to take seasonality into account?

A. Dr. Fish's unorthodox approach does not simply seek to remove the impact of seasonality within the historic test year – which is what I suggested in the last rate case. Instead, he amplifies seasonality by first adjusting customer counts to relatively high December 2007 customer levels and then inflating them further by applying an inappropriate growth factor. This approach is wholly inconsistent with the historic test year requirement.

Indeed, Dr. Fish's approach acts as a "double whammy" against UNS Gas. Adjusting to December levels *even without the growth factor* is inappropriate. December is not test-year end and the choice of December as an adjusting point appears an attempt to maximize the size of the customer annualization adjustment by adjusting to a seasonal peak. Increasing the December count by the growth factor rubs salt in the wound. The flaws in Dr. Fish's approach are many; they have been extensively discussed in my Rebuttal Testimony. In my Rebuttal Testimony, I explain that Dr. Fish is effectively using a future test-year approach to customer annualization but has failed to coordinate the revenue element of the ratemaking formula with expenses, rate base, and other components affecting rates. In short, he has violated the matching principle.

Q. Did Dr. Fish's Surrebuttal Testimony address some of your concerns?

A. No. I became even more concerned because of his continued attempts to salvage his flawed customer annualization adjustment. Dr. Fish is attempting to forecast customer counts. And a customer annualization adjustment is not identical to a forecast. The fact that he claims to have used historical data to reach his result is inconsequential to the question of whether he is forecasting. The most straightforward way to ascertain whether he is forecasting is to look at the adjusted customer counts that are the basis for his customer annualization adjustment. The customer counts to which Dr. Fish is adjusting exceed all historical regular residential and small volume commercial customer counts. Even one year <u>after</u> the end of the test-year, these customer count levels still have not been reached. In light of these results, we can say absolutely and unambiguously that the customer counts to which Dr. Fish are adjusting are not historical values. Either the customer counts to which Dr. Fish are adjusting are *future* customer counts to be realized at some indeterminate time, or they are customer counts that will never be realized, but they are certainly not historical data.

Finally, Dr. Fish defends his use of the growth rate applied to December customer counts by arguing that the growth rate was supplied by UNS Gas. However, UNS Gas never advised Dr. Fish that it should be used in calculating the customer annualization adjustment. Dr. Fish picked a growth rate more consistent with speculative forecasting and not the calculation of customer annualization adjustments. Mr. Hutchens in his Rejoinder Testimony explains in more detail why the prior growth estimate is no longer valid.

III. PHASED-IN RESIDENTIAL CUSTOMER CHARGE.

Q. Please address the issue of the phased-in residential customer charge.

A. UNS Gas' proposed phase-in of residential customer charge increases is an attempt to better align rates with cost-of-service without causing undue confusion or rate shock. UNS Gas' class cost-of-service study supports the increase. Having prices track cost is necessary for customers to make good economic decisions about resource use. Finally, from the standpoint of UNS Gas, having higher cost-based residential charges brings revenue recovery more in line with cost incurrence. Currently, UNS Gas' residential non-commodity (i.e., excluding the recovery of gas costs) revenue is recovered predominantly through volumetric energy charges ($/therm) as opposed to customer charges, whereas the lion's share of costs are fixed. Recovering fixed costs volumetrically through energy charges invariably leads to over-recovery or under-recovery of cost. A more appropriate recovery of fixed costs through customer charges promotes a matching of revenue collection with cost incursion.

Moreover, UNS Gas' proposal to gradually phase-in its higher fixed monthly charge in a revenue neutral manner serves an important emerging public policy. This rate design will help ensure that UNS Gas' financial incentives are aligned with helping its customers use energy more efficiently. It is an initial and gradual move towards de-coupling.

Q. Please address the issue of customer confusion and rate shock.

A. RUCO witness Frank F. Radigan in his Surrebuttal Testimony has expressed a concern that the phased in customer charges will cause customer confusion and he has noted that these customer charges will increase in percentage terms more than other rate components. As I have stated in my Rebuttal Testimony, too much emphasis is placed on percentage increases relative to absolute increases. Most customers are more concerned with total dollars paid for service, and are unconcerned with whether revenue is collected through a customer charge or a therm (volumetric / energy) charge.

The current residential customer charge is $8.50, which UNS Gas proposes to increase to $10.00 at rate implantation, to $12.00 one year after rate implementation, and to $14.00 two years after rate implementation. Subsequent to the initial customer charge increase to $10.00, the phased increases result in a (i.e. over two year phase-in period) $4.00 increase in the customer charge. One should remember that each customer charge increase is coupled with a therm charge *decrease*. For the average residential customer, the increased monthly customer charges will be exactly offset over the year (because of revenue neutral rate design over the class) by decreased therm charges. The maximum bill increase in the two year phase-in period subsequent to the initial rate implementation will be $4.00 per month, and that is for an unusual case where there is a customer with no usage.

Moreover, this rate design helps to mitigate inequitable subsidies to some extent. I have previously discussed how gas usage varies over the UNS Gas system because of the different climate zones the Company serves. Because of the currently inadequate customer charges, customers in cooler climates (who use more gas in the winter) are subsidizing customers in warmer zones. I do not believe that a geographical cost of

service study – suggested by Mr. Radigan - is required to justify the customer charge increases that will help mitigate this problem.

Q. Please explain why the matching of revenue to cost incursion is important to UNS Gas.

A. As explained above, the majority of UNS Gas' costs are fixed, but the majority of our revenues are collected volumetrically through charges expressed in $/therm. This leads to under-recoveries when sales are relatively low regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. Likewise, over-recoveries result when sales are relatively high. Increasing the customer charge will help mitigate periodic swings in revenue because of volatility in usage.

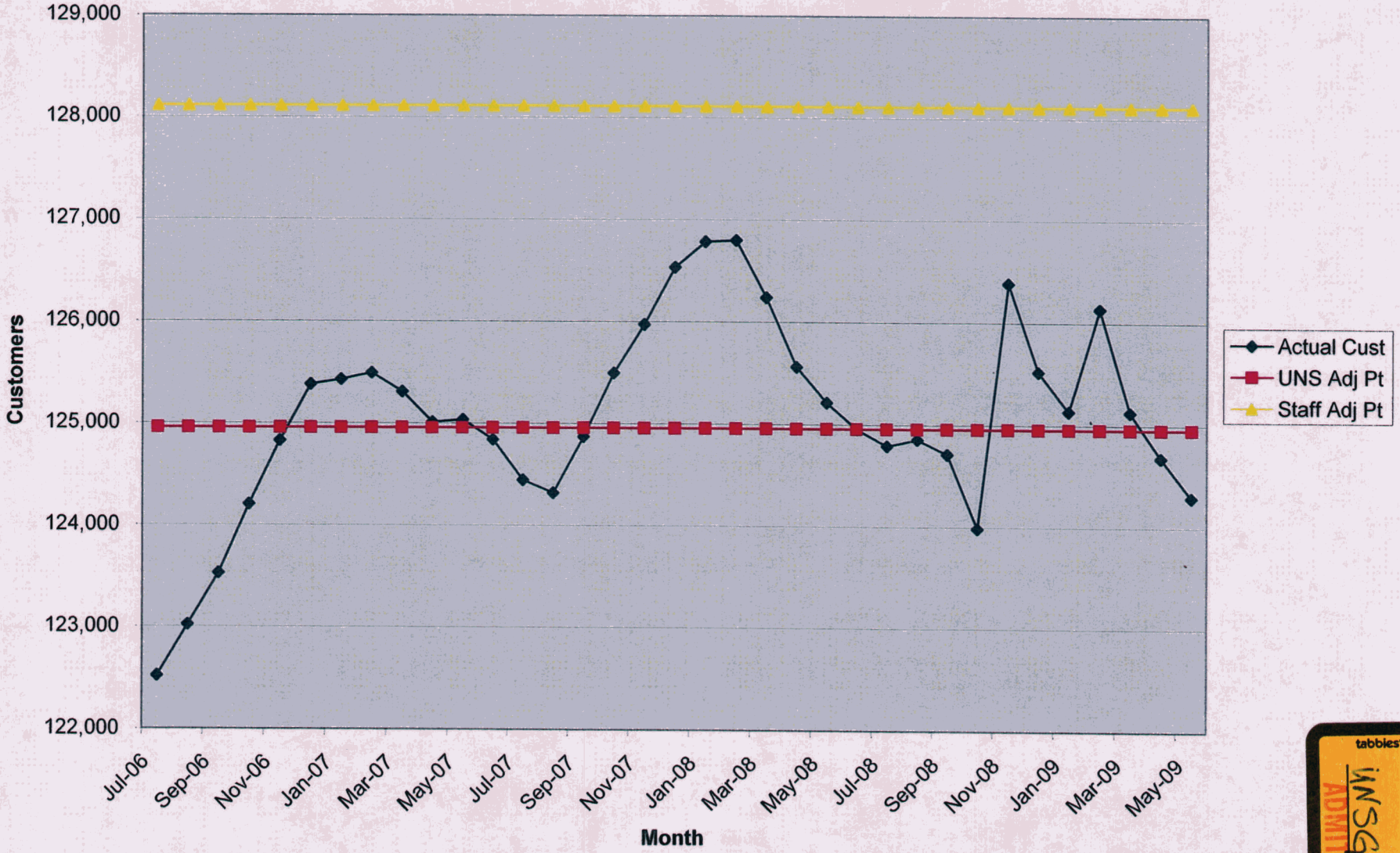
Q. Could the customer charge increase have implications for conservation and energy efficiency programs?

A. Absolutely. Under the current rate structure, sales reductions due to conservation and energy efficiency mean margin loss to UNS Gas. This is bad public policy. The Commission should move toward a rate framework that will align all stakeholders' self-interests with its growing commitment to conservation and energy efficiency. UNS Gas needs rate mechanisms that will facilitate our transition from a seller of product (where our self-interest is promoted by increasing sales) to provider of service (where the promotion of conservation has no negative impact on our financial condition). Customer charge increases are one of the simplest ways to move away from profitability tied to sales and our proposed rate design helps start the movement towards appropriate de-coupling.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

R-10 Customers over 35 Month Period with Adjusting Points



DATA REQUEST PACKET

Staff's Responses to UNS Gas' Data Requests:

UNSG 2.1	UNSG 3.10	UNSG 3.22
UNSG 2.2	UNSG 3.11	UNSG 3.39
UNSG 2.4	UNSG 3.12	UNSG 3.40
UNSG 3.4	UNSG 3.13	UNSG 3.41
UNSG 3.5	UNSG 3.14	UNSG 3.57
UNSG 3.6	UNSG 3.15	UNSG 3.58
UNSG 3.7	UNSG 3.20	UNSG 3.60
UNSG 3.9	UNSG 3.21	UNSG 3.65

EXHIBIT
UNSG 24
ADMITTED

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 2.1 Please refer to Dr. Fish's Schedule THF-C4, dealing with the Customer Annualization Adjustment. For July 2007 (month 1), R-10 customers are shown as 124,445. For December 2007 (month 6), R-10 customers are shown as 126,530. For June 2008 (month 12), R-10 customers are shown as 124,957.

a. Of what month in the test year is Dr. Fish's normalized customer count of 128,112 representative?

b. Has Dr. Fish read the Commission Decisions in the last UNS Gas rate case and the last UNS Electric rate case on the issue of customer annualization?

c. Under the approved residential annualization methodology from the last two UNS Gas and UNS Electric rate cases, does the annualization adjustment for the last month of the test year equal zero?

d. Under Dr. Fish's approach, is the residential annualization adjustment in the last month of the test-year zero?

e. Has Dr. Fish provided residential customer annualization testimony in other regulatory proceedings? If yes, please provide cites to each case (jurisdiction, case name, docket number and decision date).

f. In jurisdictions using a historical test year, has Dr. Fish ever testified in favor of a residential annualization adjustment where said adjustment was not zero in the last month of the test year?

g. In jurisdictions using a historical test year, where Dr. Fish testified in favor of a residential annualization adjustment, and where said adjustment was not zero in the last month of the test year:
   1) Was this methodology approved by the regulatory agency?
   2) Was this a settled case?
   3) Please provide the company, jurisdiction, and the party who Dr. Fish was testifying on behalf of.

h. In jurisdictions NOT using a historical test year, has Dr. Fish ever testified in favor of a residential annualization adjustment where said adjustment was not zero in the last month of the test year?

i. In jurisdictions NOT using a historical test year, where Dr. Fish testified in favor of a residential annualization adjustment where said adjustment was not zero in the last month of the test year:

1) Was this methodology approved by the regulatory agency?

2) Was this a settled case?

3) Please provide the company, jurisdiction, and the party who Dr. Fish was testifying on behalf of.

j. Please provide copies of Dr. Fish's Testimony on residential customer annualization in other rate proceedings.

k. In his Testimony, did Dr. Fish use the residential annualization methodology that was approved by the Commission in the last two UNS Gas rate cases?

l. When does Dr. Fish anticipate that the R-10 customer count would reach 128,112?

m. If no definitive answer can be provided to UNSG 2.1(l), please provide a scenario, whereby the R-10 customer count could reach at least 128,112 by December, 2008.

n. What is the implication of the R-10 customer count not reaching 128,112 by December, 2008 on Dr. Fish's customer annualization methodology?

o. What is the implication of the R-10 customer count not increasing by at least 2.5% on a year-over-year basis for most or all months of the test year (i.e., change from July 2007 to July 2008; change from August 2007 to August 2008; and change from June 2008 to June 2009)?

p. Given that Dr. Fish used a 2.5% customer growth rate in his annualization calculation, should year-over-year R-10 customer counts show a 2.5% growth rate?

q. Other than Mr. Hutchen's Testimony, does Dr. Fish have any workpaper supporting the 2.5% growth rate?

r. Has Dr. Fish examined customer counts by month and calculated year over year growth rates (or any other growth rates)?

s. UNS Gas provided total residential customers to Dr. Fish (regular residential and CARES) for August 2003 through March 2009 in response to Staff's Data Request 6.4. Has Dr. Smith examined residential customer growth rate for this data he requested?

t. If the answer to "UNSG 2.1(s). is "yes", please provide the analysis in its electronic format and specify how that examination factored into his opinion on this issue.

u. Can Dr. Fish find any basis for a 2.5% growth rate in the residential data from the response to Staff's Data Request 6.4 or any other UNS Gas residential data? If yes, please identify.

RESPONSE:

a. The number is representative of a normalized test month, but is not equal to the actual value of any single month.

b. Yes.

c. Yes.

d. No.

e. No.

f. No.

g.
1. **See answer to 2.1.f above.**
2. **See answer to 2.1.f above.**
3. **See answer to 2.1.f above.**

h. No.

i.
1. **See answer to 2.1.h above.**
2. **See answer to 2.1.h above.**
3. **See answer to 2.1.h above.**

j. See answers to 2.1.f and 2.1.h above.

k. See answers to 2.1.f and 2.1.h above.

l. Dr. Fish has not made that determination.

m. See answer to 2.1 (l).

n. See answer to 2.1 (l)

o. **See the response to numbers 2.1.p and 2.1.q. below. The implications could simply be that Mr. Hutchens projection is operating as designed.**

p. **No.**

q. **Dr. Fish did not calculate the 2.5% growth rate, the Company did.**

r. **This information was provided by the Company for rate class groupings, not by rate class as requested. However, had the information been provided as requested this type of calculation was not necessary for Dr. Fish's analysis.**

s. **Dr. Fish has used this data in his customer class risk analysis, not for year over year growth in customer counts. The work papers for this study (excel file TSCI) were provided in response to data request 1.1. Dr. Fish is unaware if Dr. Smith examined residential customer growth rate for this data.**

t. **See response to 2.1.s above.**

u. **Dr. Fish assumes that the Company's determination of its growth rate was conducted properly and has not duplicated the study.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 2.2 On page 30, line 20 through page 31, line 5, Dr. Fish states that "the Company has incentives to move as much cost, and therefore revenue recovery, to classes with the relatively greatest inelasticity of demand, i.e., residential customers."

a. Please provide any studies that purport to measure the elasticity of demand over rate classes and, if available, by cooler and warmer climate zones.

b. What is Dr. Fish's estimate of UNS Gas residential price elasticity at the current price?

c. Does Dr. Fish believe UNS Gas residential demand for natural gas in the winter is more elastic in Flagstaff or in Lake Havasu? Please provide all support for that belief.

d. What are some determinants of UNS Gas demand elasticity, and how will that affect elasticity in Flagstaff and Lake Havasu?

e. Does the UNS Gas bill represent a higher or lower percentage of income in Flagstaff, as opposed to Lake Havasu? Please provide all supporting analyses or studies for this response.

f. Other things constant, how would "natural gas bill as a percentage of income" affect elasticity on the UNS Gas system? Please provide all supporting analyses or studies for this response.

g. How does winter weather affect demand elasticity for Flagstaff versus Lake Havasu on the UNS Gas system? Please provide all supporting analyses or studies for this response.

h. How does Dr. Fish know that UNS Gas residential demand is more inelastic than UNS Gas small commercial demand? Please provide all support for Dr. Fish's assertion.

i. Is Dr. Fish alleging that revenue recovery by UNS Gas has been overly shifted to the residential class? To any other class? If yes, please provide any and all support Dr. Fish believes justifies his assertion(s).

j. Does UNS Gas use an allocation methodology that shifts a larger than typical share of costs to residential customers, in comparison to methodologies used by other utilities? Please provide all supporting analyses or studies for this response.

k. Referring to page 30 of Dr. Fish's Direct Testimony, what is a "fixed monthly residential customer"?

l. Referring to Dr. Fish's discussion of Cost of Service – Rate Design (beginning at page 29), is Dr. Fish referring to class cost allocation, or to rate design, which affects intra-class subsidies?

m. Referring to Dr. Fish's discussion of Cost of Service – Rate Design (beginning at page 29), is Dr. Fish implying that the setting of the UNS Gas residential customer charge level affects that allocation of costs among customer classes?

n. Is it Mr. Fish's position at page31, lines 1 through 5 of his Direct Testimony, that subsidies cannot be addressed without turning previously subsidizing customers into subsidized customers? If this is not the implication, please explain the point of the statement and how this belief factored into Dr. Fish's rate design proposals.

o. Is it Mr. Fish's position that all rate design subsidies should be maintained so as not to risk changing the direction of the subsidy?

p. Assume customer A has been subsidized for 5% of costs by customer B for 10 years. Further assume the rate levels must go up 6% overall to meet overall revenue requirement levels. Further assume that the subsidy of customer A could be eliminated by an 11% increase in rates to customer A, and a 1% increase in rates to B. The 5% subsidy would be maintained if A's and B's rates BOTH increase by 6%. What would be Dr. Fish's recommendation on the increase to A and B? Why?

q. If Dr. Fish's response to UNSG 2.1(p) above, that it depends on the customer's circumstances, assume that A is a residential customer earning 300% of the poverty level and B is a small commercial customer with an annual net loss from its business, what would be Dr. Fish's recommendation on the increase to A and B? Why?

r. Referring to page 30, line 8 of Dr. Fish's testimony, how does Dr. Fish define "rate shock"?

s. Please discuss the pros and cons of instituting reservation charges that would be based on the highest month's usage in peak months of November, December, January, and February.

t. Please specifically explain why changing a single customer charge once a year would be confusing to customers.

u. Please provide the number of customers who have expressed a concern that UNS Gas' rate proposal is confusing. Please provide relevant support for this number. (e.g., surveys of UNS Gas' current customers)

v. Assuming that there is less variation (less dispersion) in R-10 usage than in other classes, how does a rate redesign in the R-10 class (e.g., increase customer charge relative to volumetric charge) affect either cost allocation or rate design to any other class?

w. Please explain Dr. Fish's position for recovering fixed and variable costs through rates.

x. What is Dr. Fish's position on UNS Gas being granted a decoupling mechanism in order to make up for margin erosion attributable to energy efficiency programs?

y. Does Dr. Fish have a position on a full decoupler that would compensate for margin attributable to
1) energy efficiency,
2) abnormal weather,
3) economic fluctuations, or
4) any other factor affecting therm sales?

z. Given that a utility's stockholders expect a company to maximize profits, how would Dr. Fish – as an economist – structure cost recovery for a business model if the goal is to reduce sales of natural gas? Would the cost recovery mechanism be in the form of a decoupler, or should UNS Gas file back-to-back rates cases? Would Dr. Fish recommend a different method from the above two approaches?

RESPONSE:

a. Dr. Fish did not research the price elasticity of demand issue in his analysis. In the statement quoted in the question, Dr. Fish is referring to the economic idea of Ramsey pricing. Ramsey pricing suggests that for a given price increase, the more vertical the demand curve, the less the total revenue reduction.

b. Dr. Fish did not make an estimate of UNS Gas residential price elasticity.

c. Dr. Fish did not conduct price elasticity studies for UNS Gas customer classes or geographic areas.

d. **See the response to 2.2.c.**

e. **See the response to 2.2.c.**

f. **See the response to 2.2.c.**

g. **See the response to 2.2.c.**

h. **Dr. Fish has not conducted price elasticity studies for the Company's customer classes.**

i. **No.**

j. **Not to the knowledge of Dr. Fish.**

k. **The phrase, "fixed monthly residential customer", is a typographical error. The correct phrase is "fixed monthly residential charge."**

l. **Objection, vague and ambiguous. Without waiving the objection, the following response is provided: Dr. Fish is discussing cost allocation to customer classes and discussing rate design. However, if subsidies were a major problem it could be subsidization between classes, or "inter" class subsidies. Based on the results of his analysis and evaluation Dr. Fish has not determined that interclass subsidization is a serious problem, although the industrial class does not appear to be charged adequately for the risk it carries.**

m. **No.**

n. **No. Dr. Fish is pointing out the possibility of reversing subsidies with rate design. That is, Dr. Fish notes that rate design changes could result in customers who were once subsidized becoming subsidizers.**

o. **No.**

p. **Objection, this data request is not relevant and is not calculated to lead to the discovery of admissible evidence.**

q. **See the response to 2.2.p above.**

r. **An unexpectedly large increase in the cost of a necessary item.**

s. **For a thorough discussion of rate design considerations see Dr. Fish's Direct Testimony page 29, line19 through page 41 line 19.**

t. **See response to data request 2.2.s above.**

u. **Dr. Fish has not conducted a survey of UNS Gas customers.**

v. **The effect of relative customer class risk would be addressed in revenue spread.**

w. **See response to 2.2.s above.**

x. **Objection, this data request is not relevant and is not calculated to lead to the discovery of admissible evidence. Staff would also note that the Company has not proposed a decoupling mechanism in this case.**

y. **Objection, this data request is not relevant and is not calculated to lead to the discovery of admissible evidence. Staff would also note that the Company has not proposed a decoupling mechanism in this case.**

z. **Objection, this data request is not relevant and is not calculated to lead to the discovery of admissible evidence. Staff would also note that the Company has not proposed a decoupling mechanism in this case.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 2.4 Referring to the Direct Testimony of Staff witness Thomas H. Fish, pages 16 – 17, and his discussion of UNS Gas' Cash Advances adjustment.

a. Does Dr. Fish agree that UNS Gas had already spent the $600,000 in cash advance funds as of the end of the test year? If the answer is no, please provide supporting documentation for the assertion.

b. Does Dr. Fish believe that the projects those specific funds were spent upon are included within the original cost rate base ("OCRB") amount requested by UNS Gas? If yes, please provide detailed support for that assertion.

RESPONSE:

a. Dr. Fish agrees with the number provided in the testimony of Company witness Dallas Dukes.

b. No.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.4 Is Thomas H. Fish, Ph.D. a Certified Public Accountant?

RESPONSE: No.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.5 Please list all accounting classes taken by Thomas H. Fish, Ph.D. (including title, number of credit hours, and name of institution).

RESPONSE: **Dr. Fish obtained a Ph.D. and a masters and undergraduate degrees in economics. Masters and Doctoral level programs in economics and finance consist of a series of classes whose content include financial accounting as supporting concepts taught in the classes. The financial accounting concepts were primarily covered in the Ph.D. level finance classes.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 3.6 Refer to the Direct Testimony of Thomas H. Fish, Ph.D., page 5, line 14, where Dr. Fish refers to an "opportunity to recover these prudent costs". Please provide Dr. Fish's estimate (with supporting calculations and workpapers) of the likelihood of UNS Gas actually recovering its prudent costs if all of Staff's recommendations are adopted given observed levels of attrition and regulatory lag for UNS Gas.

RESPONSE: Objection, unduly burdensome. This information is readily available to the Company. The Commission sets rates that are just and reasonable to enable a utility the opportunity to earn its authorized rate of return.

Supplemental Response: Without waiving the objection, the following response is provided: There are no workpapers. Whether the Company recovers its costs is within the Company's control.

RESPONDENT: ROBIN MITCHELL

WITNESS: DR. THOMAS FISH

UNSG 3.7 Refer to the Direct Testimony of Thomas H. Fish, Ph.D., page 16, lines 3-5, where Dr. Fish states "Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce the costs of providing service such as maintenance cost."

a. Please provide the basis and supporting information for this statement.

b. Did Dr. Fish review the purposes of the specific items of plant included within UNS Gas' request for Post Test Year Non-Revenue Producing Plant?

c. Does Dr. Fish contend that the only reason a utility would invest in Non-Revenue Producing Plant is to increase efficiency/productivity?

d. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to maintain or improve quality of service?

e. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to meet regulatory requirements?

f. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to maintain or improve safety?

g. Please provide Dr. Fish's calculations of the estimated reduced costs of providing service in connection with the Post Test Year Non-Revenue Producing Plant.

h. Is Dr. Fish's statement regarding "reduc[ed]... costs of providing service" net of incremental depreciation expense associated with the Non-Revenue Producing Plant? If the answer is yes, please explain why Dr. Fish believes the efficiency gains exceed the incremental depreciation expense.

i. Does Dr. Fish dispute that the Post Test Year Plant requested to be included in rate base was Non-Revenue Producing? If so, please set forth each and every basis for that position and include all workpapers that provide support for Staff's belief.

j. Does Dr. Fish dispute that the Post Test Year Plant requested to be included in rate base was not related to customer growth? If so, please set forth each and every basis for that position and include all workpapers that provide support for Staff's belief.

RESPONSE:

a. **See the Company work papers accompanying this Company proposed pro forma adjustment.**

b. **The Company work papers listed and identified the expenditures but did not provide detail as to the purposes of the investment or the specific date the investment was undertaken. Also see response to UNSG 3.23 for additional information concerning this issue.**

c. **Objection, this data request mischaracterizes Dr. Fish's testimony. Without waiving the objection, the following response is provided: No. Dr. Fish considers the general terms efficiency/productivity to encompass such requirements as safety, quality of service, and regulatory requirements.**

d. **Dr. Fish acknowledges that a utility might do so.**

e. **Dr. Fish acknowledges that a utility might do so.**

f. **Dr. Fish acknowledges that a utility might do so.**

g. **Dr. Fish has not performed such calculations; the Company did not provide this information.**

h. **Objection, vague and ambiguous. This question is unclear. Without waiving the objection, the following response is provided: Dr. Fish hopes that the Company would attempt to increase its efficiency and reduce its costs. Dr. Fish has not investigated the Company's productivity and the Company refused to provide requested depreciation information. See response to UNSG 3.23, UNSG 3.7.a and UNSG 3.7.b.**

i. **Objection, this data request mischaracterizes Dr. Fish's testimony. The Company did not provide information that would allow this determination to be made in its work papers associated with this pro forma adjustment. In addition, the Company did not answer data requests that would have provided a basis for analysis of this issue. See response to UNSG 3.23 and UNSG 3.7.h.**

j. **No. Dr. Fish relied on the Company's growth estimate of 2.5% per year.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 3.9 Arizona Administrative Code R14-2-103.A.3.l defines "prudently invested" as "Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made." Under this standard, does Staff believe that the projects included within UNS Gas' requested Post Test Year Non-Revenue Producing Plant are prudently invested? If the answer is no, please specify each project that is not prudently invested and explain why.

RESPONSE: Dr. Fish has not concluded that the requested Post Test Year Non-Revenue Producing Plant are not prudently invested. Also see response to UNSG 3.23.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.10 Prior to the filing of the Direct Testimony of Thomas H. Fish, Ph.D., did Dr. Fish review the following Commission decisions regarding Post-Test Year Plant?

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

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent.

Supplemental Response: Without waiving the objection, the following response is being provided: Dr. Fish did not review these decisions.

RESPONDENT: ROBIN MITCHELL,

WITNESS: DR. THOMAS FISH

UNSG 3.11 In Rio Rico Utilities, Inc Decision No. 67279 (October 5, 2004), the Commission included non-revenue producing Post Test Year Plant in rate base. Please explain how UNS Gas' request for Post Test Year Non-Revenue Producing Plant materially differs from the post test year plant approved in Decision No. 67279.

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent. **Supplemental Response: Without waiving the objection, the following response is being provided: See response to 3.10**

RESPONDENT: ROBIN MITCHELL,

WITNESS: DR. THOMAS FISH

UNSG 3.12 In Arizona Water Company Decision No. 66849 (March 19, 2004), the Commission included non-revenue producing Post Test Year Plant in rate base. Please explain how UNS Gas' request for Post Test Year Non-Revenue Producing Plant materially differs from the post test year plant approved in Decision No. 66849.

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent. **Supplemental Response: Without waiving the objection, the following response is being provided: See response to 3.10**

RESPONDENT: ROBIN MITCHELL,

WITNESS: DR. THOMAS FISH

UNSG 3.13 In Bella Vista Water Company, Inc. Decision No. 65350 (November 1, 2002), the Commission included non-revenue producing Post Test Year Plant in rate base. Please explain how UNS Gas' request for Post Test Year Non-Revenue Producing Plant materially differs from the post test year plant approved in Decision No. 65350.

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent. **Supplemental Response: Without waiving the objection, the following response is being provided: See response to 3.10.**

RESPONDENT: ROBIN MITCHELL, DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.14 In Arizona-American Water Company Decision No. 68864 (July 28, 2006), the Commission included non-revenue producing Post Test Year Plant in rate base. Please explain how UNS Gas' request for Post Test Year Non-Revenue Producing Plant materially differs from the post test year plant approved in Decision No. 68864.

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent. **Supplemental Response: Without waiving the objection, the following response is being provided: See response to 3.10.**

RESPONDENT: ROBIN MITCHELL, DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.15 In Chaparral City Water Company Decision No. 68176 (Sept. 30, 2005), the Commission included non-revenue producing Post Test Year Plant in rate base. Please explain how UNS Gas' request for Post Test Year Non-Revenue Producing Plant materially differs from the post test year plant approved in Decision No. 68176.

RESPONSE: Objection, this data request is not relevant. Staff would also note that each Commission decision is based on the facts unique to that underlying docket. Each ACC decision stands on its own merits and no ACC decision creates a precedent. **Supplemental Response: Without waiving the objection, the following response is being provided: See response to 3.10.**

RESPONDENT: ROBIN MITCHELL

WITNESS: DR. THOMAS FISH

UNSG 3.20 Refer to the Direct Testimony of Thomas H. Fish, Ph.D., page 16, line 6-8, where Dr. Fish states that "the Company has a choice as to when it files an application for rate relief. The Company could have waited to file its application so as to include this investment in its test year."

a. Is Dr. Fish suggesting that UNS Gas file a new "pancaked" rate application at this time to include the additional plant?

b. If the response to "a." is no, is Dr. Fish suggesting that UNS Gas forego its current revenue deficiency (as identified by Staff) until a test year that includes the requested plant occurs? If so, please explain how UNS Gas would recover the revenue it would otherwise earn from the date of a Commission order in this case, to the date of a Commission order in a case with the requested plant in a test year. If the response to "a." is yes, please explain why Dr. Fish believes that this would be an economically rational course of action for a utility.

RESPONSE:

a. Dr. Fish believes that the Company is free to file an application for rate relief when it determines that it needs rate relief and that choice is entirely up to the Company. Such decision is within the Company's discretion.

b. See response to UNSG 3.20(a).

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.21 Is Dr. Fish aware of any period of time when UNS Gas stopped making new investments, particularly of the nature of the requested Post Test Year Plant, such that it could select a test year without excluding post-test year plant?

RESPONSE: It is within the Company's discretion to select a test year. Whether the Company has stopped making new investments is information possessed by the Company.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.22 Would Staff support a moratorium on installation of new plant by UNS Gas, including projects necessary for regulatory compliance, reliability or safety, such that UNS Gas would be able to include all of its plant investment within a test year?

RESPONSE: No. The Company, as a regulated utility, has the obligation to provide safe and reliable service to its customers.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.39 Does Staff dispute that UNS Gas experienced an average fuel price of $3.35/gallon during the test year?

RESPONSE: No. Gas prices have been on the decline.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.40 Does Staff believe that the future fuel costs are "known and measurable?" If so, please provide all support for that belief?

RESPONSE: No. The Commission expects that the Company will utilize its procurement policy and hedging practices to stabilize such costs.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.41 Does Staff dispute that the Call Center expense during the test year was $116,627 per month on average for UNS Gas?

RESPONSE: No. Staff relied on the information provided by the Company.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.57 Provide any evidence that SERP is an atypical cost for a gas utility.

RESPONSE: **Dr. Fish does not know that SERP is an atypical cost for a gas utility. To the extent that this request suggests that this is Dr. Fish's testimony, please provide a reference.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 3.58 Provide any evidence that UNS Gas' overall executive compensation costs are unreasonable or out of line with industry practice.

RESPONSE: Objection, this data request mischaracterizes Dr. Fish's testimony. Without waiving the objection, the following response is provided: Dr. Fish considered whether the Company should or should not recover executive compensation expenses through rates and did not represent that the Company's executive compensation costs are unreasonable or out of line with industry practice.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

UNSG 3.60 Does Dr. Fish believe that an organization is more likely to achieve specified goals when 1) achieving those goals are part of an incentive compensation plan; or when 2) compensation is entirely disconnected from achievement of goals?

RESPONSE: **Dr. Fish can respond more fully to this request when provided with a list of specified goals. Dr. Fish believes that, everything else equal, an organization might be more likely to achieve specified goals when achieving specific goals is part of a comprehensive compensation plan that may include incentives.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNSG 3.65 Regarding Dr. Fish's statement at page 31, lines 1-5, did Dr. Fish conduct any analyses regarding subsidization by cold-weather customers to warm-weather customers: (1) to UNS Gas' current rate design; (2) to UNS Gas' proposed rate design; and (3) Staff's proposed rate design? If so, please provide those analyses.

RESPONSE: No.

RESPONDENT: DR. THOMAS FISH

WITNESS: DR. THOMAS FISH

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

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 ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. G-04204A-08-____

Direct Testimony of

Denise A. Smith

on Behalf of

UNS Gas, Inc.

November 7, 2008

EXHIBIT
UNS G-25
ADMITTED

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. What is your employment position?

A. I am the Director of Conservation and Renewable Programs at Tucson Electric Power Company ("TEP"), UNS Gas, Inc. ("UNS Gas" or the "Company") and UNS Electric, Inc. ("UNS Electric"), collectively referred to as the "UniSource Energy Companies".

Q. Please describe your education and professional background.

A. I graduated from Northern Arizona University ("NAU") in 1991 earning a Bachelor of Science degree in Mathematics with an extended major in Statistics, and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in 1992 in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employees' travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, developing cost-of-service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation and Renewable Programs.

Q. Please describe the low-income assistance programs offered by UNS Gas.

A. UNS Gas offers two programs designed to assist low-income customers: the Customer Assistance Residential Energy Support ("CARES") pricing plan and the Warm Spirits Program. These programs are discussed in greater detail in Gary Smith's Direct Testimony. In addition to these two assistance programs, UNS Gas also offers the Low-Income Weatherization Program ("LIW") as part of the DSM Program Portfolio. The LIW Program will be described in Section II. below.

Q. Does UNS Gas inform customers about how fluctuating gas costs will affect their monthly bills?

A. Yes. Each fall, UNS Gas mounts a communications campaign to publicize its projections for the gas costs that will be billed to customers throughout the upcoming winter. The Company disseminates this information through bill inserts, Web site updates, print and radio advertisements and a press release. These communications follow a format that was reviewed and approved by Commission Staff several years ago.

In October 2008, a UNS Gas representative visited media outlets throughout the Company's service territory to discuss the gas price projections, promote the Company's bill payment assistance options and publicize DSM programs, including the UniSource Energy Services, Inc. ("UES") Energy Advisor and the Efficient Home Heating program. These visits were intended to encourage media coverage that provides customers with even more information about how to manage their energy expenses.

Q. Please summarize your DSM marketing activities for UNS Gas customers.

A. The marketing for the UNS Gas DSM programs will include messaging intended to promote conservation while encouraging customers to take action through participation in our new programs. Various channels will be used to drive residential and commercial

customers to uesaz.com or to the Company's call center to learn more details on the individual programs. Those channels include some advertising through media outlets such as local newspapers and trade magazines. The marketing strategy will be evaluated based on participation rates and modified if necessary to meet program goals.

Q. How does UNS Gas recover DSM program expenses?

A. The DSM adjustor charge is applied to customers' bills as a per therm charge. The DSM adjustor charge was initially set in Decision No. 70011 (November 27, 2007) and adjusted on June 1st of this year. UNS Gas is not asking for a change in the DSM adjustor mechanism or the DSM charge. The amount of the DSM charge will next be adjusted by operation of the DSM adjustor on June 1, 2009.

II. DEMAND-SIDE MANAGEMENT PROGRAMS.

Q. Does UNS Gas offer any DSM programs to its customers?

A. Yes. On February 27, 2008, the Company received approval to implement four DSM programs for customers in the UNS Gas service territory. These programs include the Low-Income Weatherization Program ("LIW"), the Efficient Home Heating Program ("EHH"), the Energy Smart Home Program ("ESH"), and the Commercial Energy Solutions Program ("CES").[1]

Q. Please describe the UNS Gas Low-Income Weatherization Program referenced above.

A. UNS Gas' 2008 annual budget for its LIW Program is $113,500 up from $75,000 in 2007 and in previous years. The LIW Program provides weatherization services to customers whose household incomes do not exceed 150 percent of the Federal Poverty Guidelines.

[1] The EHH, ESH and CES Programs were new programs, while the LIW Program already existed, but was enhanced.

The new LIW program was designed and implemented to meet requirements described in Federal and State Weatherization Assistance Program ("WAP") rules. UNS Gas contracts with community action agencies[2] throughout its service territory to make energy efficiency, and health and safety improvements to homes occupied by low-income residents, including the elderly and disabled. The LIW Program provides up to $2,000 per home for items such as increased insulation, duct sealing, furnace replacement, and other improvements allowed pursuant to the Arizona Department of Commerce Energy Office ("AEO") approved statewide Weatherization Assistance Program ("WAP"), at no additional cost to the customer.

Agencies use the process outlined in the WAP rules to determine which repairs are 'cost-effective' on each home and which repairs can be completed without risking the health and safety of the occupants. The resulting improvements in energy efficiency are intended to produce long-term savings to customers. If health and safety risks are identified, repairs to resolve the health and safety concerns must be made before the agency is allowed to implement many of the energy efficiency measures.

Training for agency personnel, as well as monitoring and evaluation of the work completed by weatherization agencies, is provided by AEO. UNS Gas provides energy records to AEO so AEO can determine actual energy and demand savings resulting from the LIW Program. AEO requires a minimum of 2 years and a maximum of 4 years of energy consumption records on each home to determine the actual savings from the UNS Gas LIW Program. Until AEO acquires sufficient energy records from actual UNS Gas customers,

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[2] These community action agencies include Western Arizona Council of Governments ("WACOG"), South Eastern Community Action Program ("SEACAP"), Northern Arizona Council of Governments ("NACOG") and Coconino County Community Services ("CCCS").

energy and demand savings will be estimated from energy records available to AEO from work completed in similar markets.

The LIW Program is marketed through weatherization agencies, through the UNS Gas call center, and on the uesaz.com web-site.

Q. Please describe the UNS Gas Efficient Home Heating Program.

A. UNS Gas' annual budget for its EHH Program is $300,000. The EHH Program provides rebates to customers who install qualifying, high-efficiency, natural gas furnaces in their homes to replace older, inefficient furnaces. The customer must be a customer of UNS Gas and the new furnace must be installed at a UNS Gas service address.[3]

The new furnace must have a minimum efficiency rating of 90 AFUE (Annual Fuel Utilization Efficiency) and UNS Gas strongly recommends installation of Energy Star qualified equipment. UNS Gas estimates that customers will save more than $2,500 over the estimated 15-year life of a new furnace.

The amount of the customer rebate depends on the type and size of equipment installed. The maximum customer rebate is $325 per unit. UNS Gas also provides installing contractors an incentive of $25 per unit for qualified equipment. The contractor incentive is provided to encourage HVAC contractors to "market" the program to customers (program marketing) and to off-set the added time required to prepare applications and support documentation required by UNS Gas before customer payments are made. Contractors must be licensed in the state of Arizona, must receive training regarding

[3] Energy efficient equipment purchased, or work contracted for or performed, prior to February 27, 2008 is not eligible for an incentive.

program rules and requirements, and sign a Participation Agreement with UNS Gas. Once they satisfy all requirements, participating contractors are listed on the uesaz.com web-site. Additionally, customers can contact the Company's call center to obtain a list of these participating contractors.

Through a Request for Proposal ("RFP") process, UNS Gas selected KEMA Services, Inc. ("KEMA") as the implementation contractor to collect applications, process rebates for both customers and contractors, and to conduct inspections on a sample of installations. KEMA is one of the world's largest and most respected energy engineering and implementation consulting firms and has been in the energy-efficiency consulting business for more than 30 years. KEMA has offices throughout the United States, including Phoenix, and has conducted application collection and rebate processing for the Arizona Public Service Company ("APS") for several years. UNS Gas provides all other marketing and implementation needs through in-house personnel.

Q. Please describe the UNS Gas Energy Smart Home Program.

A. UNS Gas' annual budget for its ESH Program is $420,000. This new home construction program promotes construction of homes that meet the 2006 ENERGY STAR® performance requirements. Energy Smart Homes are specially designed to be comfortable, durable and energy efficient in Arizona's demanding climate. Energy savings are typically achieved through a combination of building envelope upgrades, high-performance windows, controlled air filtration, upgraded heating and air conditioning systems, tight air duct systems, and inspections to ensure insulation is installed to perform at maximum efficiency. Independent third-party inspections by Home Energy Rating System ("HERS") Raters ensure that the elevated standards of an Energy Smart Home are met before the Energy Smart Home label is applied to each newly constructed home. Energy Smart Homes require less energy to operate, resulting in lower costs to consumers. Performance

standards of Energy Smart Homes also help to improve comfort, health and safety, and durability of the structure.

This Program is marketed through home builders, because decisions related to construction standards and energy efficiency are made long before homes are offered for sale. The builder is offered a rebate of $400 for each home meeting ENERGY STAR® performance requirements. Homes must also pass the independent inspection and testing requirements of ENERGY STAR®. The builder is required to pay the independent HERS rater to perform inspections and testing on a pre-determined sample of homes. The $400 rebate offered by UNS Gas helps to off-set the cost of the required HERS rating, inspections, and testing but does not completely cover this added cost.

Through a RFP process, UNS Gas selected the Conservation Services Group ("CSG") as the implementation contractor for this Program. CSG is a non-profit entity that has been specializing in residential energy efficiency program implementation for 25 years. They are the implementation contractor for new home construction programs in Massachusetts, Rhode Island, New York, New Jersey, Oregon, and California. CSG will provide turn-key services to UNS Gas and has recently hired local staff to help implement the UNS Gas program. The CSG team consists of a program manager and on-the-ground local account managers, backed-up by central marketing, technical, administrative, and customer service support. UNS Gas provides an in-house account manager to over-see activities of the CSG group, provide support and liaison activities to support CSG, manage budgets, and develop reports for the Company and the Arizona Corporation Commission ("Commission").

Q. Please describe the UNS Gas Commercial Energy Solutions Program.

A. UNS Gas' annual budget for its CES Program is $200,000. The CES Program provides rebates to commercial customers to encourage the installation of high-efficiency gas

equipment in commercial facilities, and to help reduce the initial cost of purchasing more efficient equipment. Rebates are offered for high-efficiency water heaters, furnaces, boilers, and commercial kitchen griddles. Rebates of up to $350 are paid for installation of each qualifying high efficiency furnace, but rebates vary based on the size and efficiency of the equipment. Rebates of $200 are paid for each qualifying storage water heater, $250 for each qualifying boiler, and $300 for each qualifying griddle.[4]

To be eligible for a rebate, the account must receive gas service under one of these UNS Gas rate schedules: C20, C22, I-30, I-32, PA-40, PA-42, PA-44, IR-60 or Commercial, Industrial and Public Authority Transportation rates. The incentive cap for the CES Program is $8,000 per customer, per calendar year. School districts with grades kindergarten through 12th grade may receive up to $25,000 per calendar year.

Through a RFP process, UNS Gas selected KEMA as the implementation contractor to provide turn-key services for the CES program. As previously mentioned, KEMA is one of the world's largest and most respected energy engineering and implementation consulting firms and has been in the energy-efficiency consulting business for more than 30 years. KEMA has offices throughout the United States, including Phoenix, and has recently hired staff to support the UNS Gas CES Program. UNS Gas provides an in-house account manager to over-see activities of KEMA, provide support and liaison activities to support KEMA, manage budgets, and develop reports for the Company and the Commission.

UNS Gas will utilize many communication vehicles for marketing, outreach and information dissemination for the CES Program. At times the direct marketing approach,

[4] Energy efficient equipment purchased, or work contracted for or performed, prior to February 27, 2008 is not eligible for an incentive.

such as direct mail and telemarketing, are not effective instruments to reach commercial customers. UNS Gas will emphasize indirect and leveraged marketing methods instead, and will leverage alliances with associations to explore opportunities for free or low-cost advertising. Free press, bill inserts, websites, e-mail blasts, and community presentations to reach the target market are effective ways to get the message out with relatively minimal cost.

Q. What is the status of each of the UNS Gas DSM Programs?

A. **Low-Income Weatherization:** UNS Gas provided advance notification to the LIW agencies about the new program and the requirement to meet WAP rules once the Program was approved. Agencies agreed to begin using the new process in January 2008. As a result of the early notification to agencies, the UNS Gas LIW Program was fully implemented on February 27, 2008, the effective date of Decision No. 70180 which approved the LIW Program.

Efficient Home Heating Program: This program is the first DSM program ever offered by a gas utility to customers in this service territory. It is challenging to launch new programs from a 'cold start' in a market with little experience with these types of programs. However, UNS Gas successfully recruited 29 HVAC contractors willing to participate in the Program and publicly launched the EHH Program on June 16, 2008; the first application was received at the end of June 2008. Program participation for rebates has been greater than anticipated in a new market. From June 16th through September 30th, 2008 UNS Gas paid rebates for 41 new high-efficiency furnaces. UNS Gas anticipates even greater participation during the winter heating season.

Energy Smart Home: New Home Construction programs always require a much longer start-up period than other product-specific DSM programs. UNS Gas is partnering with its

implementation partner CSG, to identify potential customers, develop processes, develop webpage content and marketing materials, and determine tracking requirements for the program. CSG recently completed the process to recruit, interview, hire, and train employees to support efforts in the UNS Gas service territory. UNS Gas is also working to develop a network of certified HERS raters to support the inspection and testing requirements of the Program. UNS Gas developed the website content and began discussions with builders in Santa Cruz County in June 2008, and with builders in Mohave, Coconino, and Yavapai Counties in September 2008.

UNS Gas recognizes that the educational process, builder recruitment, and builder and sub-contractor training will take time. The depressed housing market also means there are significantly fewer new homes under construction at this time. Even after a builder commits to use the ESH construction standards, it is not uncommon for the construction process to last 6 months before home completion. As a result, UNS Gas hopes to have a few committed projects in 2008, but anticipates there will be no completed homes until at least the 3rd quarter of 2009.

Commercial Energy Solutions: This is the first commercial DSM program for gas products ever offered by a gas utility to commercial customers in this service territory. Again, it is challenging to launch new programs from a 'cold start' in a market with little experience with these types of programs.

UNS Gas and its implementation partner KEMA have worked together to identify potential customers, develop processes, design webpage content, identify tracking requirements, develop application forms, and develop policies and procedures. KEMA has completed the process to recruit, interview, hire, and train new employees to implement the Program within the UNS Gas service territory. UNS Gas launched the website content, completed

application forms, completed the program policies and procedures, and arranged for call-center support to handle inquires by June 16, 2008, and the complete infrastructure to support this Program was in place by August 2008.

In addition to web-site information, UNS Gas trained employees to recruit customers for the program during presentations and community events, and placed an ad in a Chamber of Commerce magazine. UNS Gas met with contractors, distributors and trade allies to announce the Program. Distributors are important trade allies to this process to make sure qualifying equipment is available for contractors in the UNS Gas service territory. Contractors are important as they are commonly the first to know that a customer is looking for new gas equipment.

UNS Gas received its first application from a commercial customer for a rebate in October 2008. UNS Gas understands that rebate requests for qualifying furnaces during the summer months may not be common and anticipates more activity during the winter heating season. During distributor and contractor meetings it was determined that qualifying water heaters and boiler were not readily available to contractors. UNS Gas is working with distributors to investigate avenues to ensure qualifying equipment is available to commercial customers.

Q. Is UNS Gas reviewing new DSM programs for future implementation?

A. While electric utilities have a number of possibilities for developing programs that reduce demand and energy consumption, gas utilities are limited due to the smaller number of gas products installed for residential and commercial end use. UNS Gas is considering some possible program additions for future implementation, however it is uncertain at this time whether these programs will meet required cost-effectiveness tests.

These potential program additions include the following:

1) **Envelope and duct leakage improvements:** UNS Gas is one of seven electric and gas utilities participating in a state-wide effort to study the effects of envelope and duct leakage improvements in existing homes. This study is being funded by a DOE grant awarded to the AEO in September 2008. Results of this study will be used to determine the cost, benefit, and process required to successfully launch an existing home program. Results will not be available for at least 18 months. At that time, UNS Gas may consider an envelope improvement program for existing homes.

2) **Rebates for high-efficiency storage water heaters:** UNS Gas will consider providing rebates for high-efficiency storage water heaters to residential customers. A program will only be recommended if it is determined to meet the societal cost test required for program approval. To date residential water heating programs traditionally have struggled to meet the cost effectiveness test.

3) **Expanding measures for the Commercial Energy Solutions Program:** UNS Gas will continually evaluate the feasibility of expanding measures within its Commercial Energy Solutions Program. One consideration is to provide rebates for duct-sealing in commercial buildings. As new gas technologies become available, UNS Gas will perform analysis to determine cost effectiveness. A measure will only be recommended if it is determined to meet the societal cost test required for program approval.

Q. Does this complete your Direct Testimony regarding DSM activities for UNS Gas?

A. Yes, this completes my testimony.

UNS GAS DISCONNECT NUMBERS 2006 THRU 2009

UNS Gas		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
# Disconnect Orders Worked	2006	0	0	0	351	698	625	372	344	348	280	277	150	3445
	2007	352	345	243	0	0	965	921	684	476	377	308	253	4,924
	2008	401	413	703	911	633	512	578	547	363	422	253	327	6,063
	2009	665	355	775	878	582	684	404						4,343

* No Disconnects January - March, 2006 due to ACC imposed moratorium.
* No Disconnect April - May '07 for UNS Gas and Electric due to CC&B Conversion

EXHIBIT
UNS 626
ADMITTED

UNS Gas CARES Disconnections

2007

Number of CARES customers disconnected for non payment: ~~180~~* 238

Number of CARES customer-requested disconnections: ~~449*~~ 1,532

In 2007, of our total disconnections for non payment orders, ~~3.6%~~ 4.8 were CARES.

2008

Number of CARES customers disconnected for non payment: ~~253~~ 349

Number of CARES customer-requested disconnections: ~~269~~ 1,504

In 2008, of our total disconnections for non payment orders, ~~4.1%~~ 5.7 were CARES.

*Note: 2007 statistics April through December due to CCB conversion.

UNSG 27 (amended)

EXHIBIT
UNSG 27
ADMITTED

UNS Gas CARES Deposits

2007:

Number of CARES customers year end 2007:	6,725
Number of CARES customers w/deposit:	1,327
Average deposit amount:	$88.12
20% of our CARES customers have deposits	

2008:

Number of CARES customers year end 2008:	7,536
Number of CARES customers w/deposit:	1,329
Average deposit amount:	$94.86
18% of our CARES customers have deposits	

2009:

Number of CARES customers 2009 ytd:	7,932
Number of CARES customers w/deposit:	1,453
Average deposit amount:	$100.48
18% of our CARES customers have deposits	

EXHIBIT
UNSG 28
ADMITTED

Warm Spirit Contributions 2007, 2008, 2009
UNS Gas, Inc.

Per G/L			Totals
Customer Contributions	**2007**	**$**	**14,541.76**
Company Match		**$**	**14,571.76**
Customer Contributions	**2008**	**$**	**22,522.58**
Company Match		**$**	**22,522.58**
Customer Contributions	**2009**		
Through July		**$**	**12,815.15**
Company Match		**$**	**12,815.15**

EXHIBIT
UNSG29
ADMITTED

For Customer Inquiries, Construction or Deliveries, Please Use the Intercom

Customer transactions and inquiries also can be handled online at uesaz.com, or by calling the UES Customer Care Center toll-free at 877-UES-4YOU (877-837-4968) Monday through Friday, 7 a.m. to 7 p.m.

NOTE:

Lobby Does Not Take Payments

UES Bill Payment Options

SNAP – (Sure No-hassle Automatic Payment) – Enjoy the convenience of automatically paying your bill each month from your checking or savings account. It's easy. It's safe. It's FREE. Visit **uesaz.com** or call UES Customer Care Center toll-free at 877-837-4968 to begin automatically paying your bill.

UES e-bill – *UES e-bill* is the online, fast, simple, convenient, secure, guaranteed, anywhere, anytime, FREE way to pay your UES bill. Visit **uesaz.com** or call UES Customer Care Center toll-free at 877-837-4968 to begin viewing or paying your bill online.

Credit or Debit Card Payment

Web – Pay your bill online at uesaz.com (a convenience fee of $3.95 for payment of bills up to $250 will be charged by a third-party payment processing company, additional fees may be charged for bills over $250).

Telephone – Call our toll-free payment hotline: 800-284-9730 (a convenience fee of $3.95 for payment of bills up to $250 will be charged by a third-party payment processing company, additional fees may be charged for bills over $250).

Walmart – You may pay your bill with cash or a debit card at your local Kingman Walmart Supercenter, 3396 No. Stockton Hill Road – (928) 692-0555. A service fee of $0.88 will apply.

Courtesy Drop Box – Drop box payments of check or money order can be made at:

- UniSource Energy Services, 2498 Airway Avenue, Kingman
- Kingman City Hall 310 N. 4th Street

U S Mail – It may not be high-tech, but it gets the job done for your check or money order payment. We supply the envelope, you supply the stamp.

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November 7, 2008

Assessing U.S. Utility Regulatory Environments

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EXHIBIT
UMS831
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Assessing U.S. Utility Regulatory Environments

The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most. In our credit analysis, we evaluate regulatory risk on a company-specific basis. A utility management's skill in managing regulatory risk can in many cases overcome a difficult regulatory environment. Conversely, other companies can experience greater regulatory risk even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. Operating in a state with a regulatory structure that is conducive to maintaining credit quality will improve the chances for a utility to successfully negotiate the regulatory maze.

This commentary discusses our views on what constitutes a favorable regulatory climate. We then use those factors to create assessments of the regulatory environments in states that regulate the electric and gas utilities that we rate. (See the table at the end of this article.) Our intention is to provide a common base for our own analysis of regulatory risk and to better communicate to investors, issuers, and regulators how various elements of regulation can affect credit quality. The exercise is also expected to enhance our ability to evaluate management by highlighting instances where our opinion of a company's regulatory risk diverges significantly from the fundamental quality of the regulatory jurisdictions where it operates.

The assessments of relevant jurisdictions are based on quantitative and qualitative factors. Importantly, we make our assessments from a credit perspective. We plan to update them annually or when significant events occur that have an important impact on the regulatory climate in a particular jurisdiction. The new regulatory assessment information augments the methodology applied to regulated utilities today.

Our introduction of these regulatory assessments coincides with what we view as the increasing influence of regulatory matters on the rated utilities' risk profiles and greater credit market awareness of the importance of understanding the regulatory process. Our goal in explaining our views on regulatory practices and policies and their effect on Standard & Poor's analysis of the credit quality of utilities is to provide additional transparency to the market.

Background

State utility regulation is almost as old as credit ratings. Standard & Poor's predecessor, Standard Statistics Bureau, was formed in 1906, and the first state utility commissions, as we know them today, appeared in 1907. Regulation has always been a factor in Standard & Poor's analysis of utility ratings, but its importance to our analysis has shifted with industry trends over time.

Before the 1970s, regulators presided for the most part over stable or decreasing rates as economic growth, rising consumption, and economies of scale drove costs down. The advent of inflation, rising and volatile fuel costs, and nuclear power missteps led to higher rates and, in our view, greater regulatory influence on credit quality during the 1980s. Restructuring in the natural gas and then the electric industries marked the 1990s and the first years of the new millennium, and the importance of regulatory issues in our analysis again started to subside. In our view, we are

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now in another era of increasing and unstable costs and some semblance of a return to traditional utility regulation. Consequently, the quality of regulation is at the forefront of our analysis of utility creditworthiness.

We have historically focused on regulatory risk on a company-specific basis. Nothing in what follows will change that approach. Utility commissions regulate diverse industries and adopt different approaches to different types of businesses. Treatment of utilities within the same industry can vary significantly in the same jurisdiction. The quality of the regulation experienced by a company is often the product of the company's management and business strategy as much as its regulators. The regulatory climate assessments only serve as a baseline of our opinion on the fundamental attitude of a jurisdiction toward the credit quality of the utilities in that state, and they are the starting point for Standard & Poor's analysis of the regulatory risk of each rated utility. Our goal is to achieve greater consistency and continuity in utility ratings.

Assessing Regulatory Jurisdictions

We assess jurisdictions on one basic attribute--the fundamental approach to controlling utility rates--and then in three major categories. The resulting assessments are based primarily on various measures of regulatory risk that are discussed briefly below. With respect to qualitative factors, we look for long-term, historical characteristics of the jurisdiction, as well as transient regulatory and political developments.

The foundation of our opinion of the regulation in a jurisdiction is the degree to which competitive market forces are allowed to influence rates. In order of credit-friendliness, a state will rely either on full cost-based regulation for all components of the utility bill, market-based mechanisms for generation, and (more rarely) retail markets, or a hybrid of the two to control the amount charged and the terms on which that service is offered. It may surprise some to learn that we consider a hybrid setup, which in most cases exists because the transition to some sort of competition has stalled, to harbor more risk for bondholders than a system that is committed to letting market prices set a major part of the customer's bill.

The risk inherent in the market-based model is straightforward: the price for electricity can be more volatile when based on a market than when it is based on embedded costs, and regulators are apt to resist full and timely recovery when changes in generation costs are abrupt and substantial (and perhaps misunderstood). The risks in a hybrid or transitional model are less apparent, but, in our opinion, potentially more significant. First, we consider the uncertainty of the timing of reaching the end state--and what that end state will look like--to be a negative factor from a credit perspective. Second, in some cases, the hybrid model may result in a "lower-of-cost-or-market" approach that allows generation rates to reflect one or the other at different times depending on which one suits ratepayers best. A utility and its bondholders may then face a prolonged period of potential exposure to market risk (the downside) with little or no opportunity to participate in the benefits of competition (the upside of greater returns).

After identifying the fundamental regulatory paradigm, our analysis turns to factors that influence the utility's business risk climate in the jurisdiction. The factors fall into three broad categories: ratemaking, political environment, and financial stability. Broadly speaking, the ratemaking and financial stability factors influence our assessments more than the paradigm and political factors.

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Ratemaking Practices And Procedures

The main, and often the most contentious, task of a regulator is to set the rates a utility may charge its customers. We analyze specific rate decisions as part of the surveillance of each utility. Our regulatory assessments focus on the jurisdiction's overall approach to setting rates and the process it uses to conduct and manage base rate filings. Practices pertaining to separate tariff clauses for large expense items are examined in the third category of the analysis (see below). In this part of the assessment, we concentrate on whether established base rates fairly reflect the cost structure of a utility and allow management an opportunity to earn a compensatory return that provides bondholders with a financial cushion that promotes credit quality.

Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc. Although, in general, the absolute level of financial returns is less important to our analysis than how that return is earned, we recognize that, all else being equal, higher earned returns translate into better credit metrics and a more comfortable equity cushion for bondholders. A regulatory approach that allows utilities the opportunity to consistently earn a reasonable return is a positive factor in our view of credit quality.

The rates of return and capital structures used to generate the revenue requirement in rate proceedings may not be the primary focus of the assessment, but those and other decisions made in the ratemaking process are still noted. We consider those decisions to be potential signals from regulators on their attitude toward credit quality. We believe that the capital structure in particular is a handy and direct indication from the regulator as to whether or not creditworthiness is an important consideration in its deliberations when setting rates. Obviously, any pronouncements from a regulator that explicitly address credit ratings or ratemaking practices that incorporate credit-minded adjustments (e.g., the use of double-leveraged capital structures or off-balance-sheet debt-like obligations) are considered in the Standard & Poor's assessment.

We analyze the issue of "regulatory lag" in a comprehensive manner and not just as a matter of the efficiency of the regulator in completing rate cases. As part of this analysis, we evaluate the timeliness of rate decisions, coupled with an evaluation of the test year. In addition, we take into account the timing of interim rates, and other practices that affect the appropriateness of rates periodically established by the regulator. We do not view the issue of regulatory lag as an intermittent concern, consequential only during times of acute inflation or rising capital spending, but as a consistent part of our credit analysis. Accordingly, in our regulatory assessments we focus on whether the regulator efficiently prosecutes rate requests and bases its decisions with respect to rate setting on the most current information.

In our view, the prevalence of rate case settlements is not necessarily an important credit consideration. Although the common assumption among market participants seems to be that a settlement must be in the best interest of a utility, we believe this assumption disregards the possibility that management will sometimes make decisions based on its effect on earnings at the expense of cash flow considerations. This does not mean we dismiss the ability of stipulations to reach a fair resolution of difficult matters that help regulators issue timely and constructive rate decisions. It just means that frequent settlements do not, in our view, directly lead to a conclusion that the regulatory environment in a state enhances credit quality.

An important policy-related issue outside of individual rate cases that falls under this part of the assessment is the

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regulatory oversight of large capital projects with long lead times that carry out-sized risks to a utility and its bondholders. In our opinion, practices such as legislative or regulatory recognition of the need for pre-approval of such endeavors, periodic reviews that substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk associated with a utility committing substantial capital well in advance of the rate proceeding that results in the project being placed into rate base. Before committing to such projects, a resource-procurement process that uses objective guidelines to evaluate competing proposals to meet load obligations and keeps the regulator informed and involved in the decisions can, in our view, help to reduce the risk of subsequent disallowances. If the jurisdiction has an Integrated Resource Plan or similar mechanism that includes the participation of many parties and is used to definitively establish the need for new generation, we consider credit risk to be further diminished.

One more factor that we examine in this part of the analysis is whether a jurisdiction employs nontraditional ratemaking practices. Examples of what we may view to be potentially credit-enhancing regulatory mechanisms include weather normalization and incentive ratemaking. We believe that the beneficial effect on credit quality of a tariff clause that smooths out cash flows that can vary with outside influences like weather is self evident. The benefits of incentives incorporated into the regulatory regime may be less clear. Well-designed incentives can be at least credit neutral. A moderate amount of incentives can be credit supportive. We generally view incentive provisions (whether tied to cost control, reliability, or operational performance) as being beneficial for credit quality if they are linked to fair and objective benchmarks. Incentives that lack some or all of those features, such as a plain, long-term rate freeze, can be, in our opinion, detrimental to credit quality.

Political Insulation

The role of politics in utility regulation is often misunderstood. In most jurisdictions, legislatures created regulatory commissions and invested them with the power to set and enforce utility rates and service standards. Regardless of how a regulatory commission is statutorily organized, its function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service but for other constituents as well. In this regard, bondholders should recognize that the setting of utility rates invariably reflects political as well as economic factors. Therefore, the potential for political considerations to affect utility regulation can be a key determinant when we assess a regulatory jurisdiction.

A primary factor in this part of our assessment is the method of selecting utility commissioners. In some jurisdictions, the governors appoint regulatory commissioners. In others, the same voters who pay utility bills directly elect commissioners. The regulatory risk associated with that model can sometimes be managed, but there is an inherent level of risk in elected regulatory bodies that we reflect in the assessment. Standard & Poor's also analyzes the track record of the involvement of the executive branch or the legislature in utility matters, and the relative visibility of utility issues in the political arena.

The ability of a regulator to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utility managers in managing business and financial risk can be affected by the overall atmosphere that it operates in. The tone can be set by the governor or legislature, the history and tradition of independence accorded to the regulatory body, and the behavior of important constituent groups that intervene in utility proceedings.

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Cash Flow Support And Stability

The final set of factors in our assessment of regulatory environments is arguably the most important. The phrase "cash is king" can be overused, but it does highlight an essential part of the credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision making is one that will appeal to bondholders. Generating cash is a function of the actions of utility management, but the regulator can supply (or withhold) the tools that can affect the company's essential ability to actually realize the intended level of cash flow.

The most prominent factor in this part of the analysis is the application of separate tariff provisions for major expenses such as fuel and purchased power. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of the control of utility management is a key component of a credit-enhancing regulatory jurisdiction. We analyze the quality of special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect the analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part in the regulatory assessment.

The commission's policies and oversight covering hedging activities may also be a factor in this part of the review if a utility has sought regulatory approval. For utilities that attempt to manage commodity risks, we look for a clearly-stated hedging policy and a track record of activity that conforms to that policy. The responsibility for communicating the policy and demonstrating the prudence of the hedging activity rests with the utility, but the initial response to a hedging program and the history of the regulator's treatment of the results of the program could influence our assessment.

Regulators can employ other ratemaking techniques that promote stable cash flows. We consider a commission's decisions on rate design in assessing its attitude on credit quality. For example, we take into account the relative size of the typical monthly customer charge, a decoupling mechanism that severs the direct relationship between revenues and customer usage, or other rate design features that bolster credit quality.

Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program.

Jurisdictional Assessments

The table below shows Standard & Poor's assessments of regulatory jurisdictions. The category titles are designed to communicate one other important point regarding utility regulation and its effect on ratings. All categories are denoted as "credit-supportive". To one degree or another, all U.S. utility regulation sustains credit quality when compared with the rest of corporate ratings at Standard & Poor's. The presence of regulators, no matter where in

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the spectrum of our assessments, reduces business risk and generally supports all U.S. utility ratings.

Regulatory Jurisdictions For Utilities Among U.S. States

Most credit supportive	More credit supportive	Credit supportive	Less credit supportive	Least credit supportive
	Alabama	Arkansas	Louisiana	Arizona
	California	Colorado	Maine	Delaware
	Florida	Connecticut	Missouri	Dist. of Columbia
	Georgia	Hawaii	Montana	Illinois
	Indiana	Idaho	New York	Maryland
	Iowa	Kansas	Oklahoma	New Mexico
	South Carolina	Kentucky	Rhode Island	
	Wisconsin	Massachusetts	Texas	
		Michigan	Utah	
		Minnesota	Vermont	
		Mississippi	Washington	
		Nevada	West Virginia	
		New Hampshire	Wyoming	
		New Jersey		
		North Carolina		
		North Dakota		
		Ohio		
		Oregon		
		Pennsylvania		
		South Dakota		
		Virginia		

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Arizona Workforce Informer

Historical Data for Unemployment Rate in Coconino County

Year	Prelim	Period	Labor Force	No.of Employed	No.of Unemployed	Unemployment Rate %
2009	Preliminary	Jan	75,206	70,014	5,192	6.9
2009	Preliminary	Feb	73,987	68,928	5,059	6.8
2009	Preliminary	Mar	73,154	68,373	4,781	6.5
2009	Preliminary	Apr	73,779	69,532	4,247	5.8
2009	Preliminary	May	72,982	68,492	4,490	6.2
2009	Preliminary	Jun	73,372	67,792	5,580	7.6
2008	Not Preliminary	Annual	73,433	69,679	3,754	5.1
2008	Not Preliminary	Jan	70,223	66,749	3,474	4.9
2008	Not Preliminary	Feb	70,245	67,018	3,227	4.6
2008	Not Preliminary	Mar	71,730	68,541	3,189	4.4
2008	Not Preliminary	Apr	72,789	69,959	2,830	3.9
2008	Not Preliminary	May	73,745	70,689	3,056	4.1
2008	Not Preliminary	Jun	75,497	71,590	3,907	5.2
2008	Not Preliminary	Jul	75,290	71,071	4,219	5.6
2008	Not Preliminary	Aug	74,105	69,914	4,191	5.7
2008	Not Preliminary	Sep	74,216	70,252	3,964	5.3
2008	Not Preliminary	Oct	74,558	70,554	4,004	5.4
2008	Not Preliminary	Nov	74,506	70,254	4,252	5.7
2008	Not Preliminary	Dec	74,288	69,557	4,731	6.4
2007	Not Preliminary	Annual	70,859	68,240	2,619	3.7
2007	Not Preliminary	Jan	68,537	65,416	3,121	4.6
2007	Not Preliminary	Feb	68,614	65,827	2,787	4.1
2007	Not Preliminary	Mar	69,116	66,526	2,590	3.7
2007	Not Preliminary	Apr	69,832	67,570	2,262	3.2
2007	Not Preliminary	May	70,133	68,128	2,005	2.9
2007	Not Preliminary	Jun	72,066	69,490	2,576	3.6
2007	Not Preliminary	Jul	73,228	70,346	2,882	3.9
2007	Not Preliminary	Aug	71,314	68,800	2,514	3.5
2007	Not Preliminary	Sep	72,427	70,011	2,416	3.3
2007	Not Preliminary	Oct	72,359	69,908	2,451	3.4
2007	Not Preliminary	Nov	71,740	69,111	2,629	3.7
2007	Not Preliminary	Dec	70,932	67,742	3,190	4.5
2006	Not Preliminary	Annual	69,118	66,171	2,947	4.3
2006	Not Preliminary	Jan	65,991	62,612	3,379	5.1
2006	Not Preliminary	Feb	66,671	63,507	3,164	4.7
2006	Not Preliminary	Mar	67,435	64,530	2,905	4.3
2006	Not Preliminary	Apr	68,027	65,344	2,683	3.9
2006	Not Preliminary	May	68,499	65,828	2,671	3.9
2006	Not Preliminary	Jun	70,903	67,660	3,243	4.6
2006	Not Preliminary	Jul	71,109	67,671	3,438	4.8
2006	Not Preliminary	Aug	69,914	66,877	3,037	4.3
2006	Not Preliminary	Sep	70,842	68,113	2,729	3.9
2006	Not Preliminary	Oct	70,851	68,203	2,648	3.7
2006	Not Preliminary	Nov	70,093	67,467	2,626	3.7
2006	Not Preliminary	Dec	69,086	66,241	2,845	4.1
2005	Not Preliminary	Annual	67,531	64,245	3,286	4.9
2005	Not Preliminary	Jan	65,065	61,398	3,667	5.6
2005	Not Preliminary	Feb	65,464	62,049	3,415	5.2
2005	Not Preliminary	Mar	65,959	62,653	3,306	5
2005	Not Preliminary	Apr	66,593	63,600	2,993	4.5
2005	Not Preliminary	May	66,886	63,990	2,896	4.3
2005	Not Preliminary	Jun	69,301	65,764	3,537	5.1
2005	Not Preliminary	Jul	69,447	65,753	3,694	5.3
2005	Not Preliminary	Aug	68,567	65,243	3,324	4.8
2005	Not Preliminary	Sep	69,332	66,164	3,168	4.6
2005	Not Preliminary	Oct	68,931	65,859	3,072	4.5
2005	Not Preliminary	Nov	67,854	64,714	3,140	4.6
2005	Not Preliminary	Dec	66,977	63,757	3,220	4.8

EXHIBIT
WMSG 32
ADMITTED

Arizona Workforce Informer

Historical Data for Unemployment Rate in Mohave County

Year	Prelim	Period	Labor Force	No.of Employed	No.of Unemployed	Unemployment Rate %
2009	Preliminary	Jan	94,227	85,240	8,987	9.5
2009	Preliminary	Feb	93,837	85,140	8,697	9.3
2009	Preliminary	Mar	93,596	84,672	8,924	9.5
2009	Preliminary	Apr	93,479	85,257	8,222	8.8
2009	Preliminary	May	93,431	85,008	8,423	9
2009	Preliminary	Jun	94,553	85,331	9,222	9.8
2008	Not Preliminary	Annual	93,421	86,918	6,503	7
2008	Not Preliminary	Jan	91,686	86,112	5,574	6.1
2008	Not Preliminary	Feb	91,908	86,615	5,293	5.8
2008	Not Preliminary	Mar	92,702	87,218	5,484	5.9
2008	Not Preliminary	Apr	93,267	88,141	5,126	5.5
2008	Not Preliminary	May	93,933	88,140	5,793	6.2
2008	Not Preliminary	Jun	95,859	89,580	6,279	6.6
2008	Not Preliminary	Jul	95,167	88,395	6,772	7.1
2008	Not Preliminary	Aug	93,477	86,173	7,304	7.8
2008	Not Preliminary	Sep	93,206	86,032	7,174	7.7
2008	Not Preliminary	Oct	93,186	85,694	7,492	8
2008	Not Preliminary	Nov	93,344	85,637	7,707	8.3
2008	Not Preliminary	Dec	93,312	85,273	8,039	8.6
2007	Not Preliminary	Annual	91,583	87,357	4,226	4.6
2007	Not Preliminary	Jan	92,828	88,342	4,486	4.8
2007	Not Preliminary	Feb	92,005	88,020	3,985	4.3
2007	Not Preliminary	Mar	92,673	88,698	3,975	4.3
2007	Not Preliminary	Apr	91,703	87,984	3,719	4.1
2007	Not Preliminary	May	91,781	88,262	3,519	3.8
2007	Not Preliminary	Jun	92,622	88,649	3,973	4.3
2007	Not Preliminary	Jul	92,257	87,988	4,269	4.6
2007	Not Preliminary	Aug	91,077	86,772	4,305	4.7
2007	Not Preliminary	Sep	90,985	86,635	4,350	4.8
2007	Not Preliminary	Oct	90,222	85,720	4,502	5
2007	Not Preliminary	Nov	90,432	85,836	4,596	5.1
2007	Not Preliminary	Dec	90,410	85,378	5,032	5.6
2006	Not Preliminary	Annual	92,372	88,458	3,914	4.2
2006	Not Preliminary	Jan	91,534	87,222	4,312	4.7
2006	Not Preliminary	Feb	90,924	86,916	4,008	4.4
2006	Not Preliminary	Mar	91,973	88,368	3,605	3.9
2006	Not Preliminary	Apr	92,253	88,723	3,530	3.8
2006	Not Preliminary	May	92,551	89,257	3,294	3.6
2006	Not Preliminary	Jun	94,018	89,907	4,111	4.4
2006	Not Preliminary	Jul	93,758	89,538	4,220	4.5
2006	Not Preliminary	Aug	92,782	88,798	3,984	4.3
2006	Not Preliminary	Sep	92,691	88,623	4,068	4.4
2006	Not Preliminary	Oct	92,020	88,026	3,994	4.3
2006	Not Preliminary	Nov	91,991	88,071	3,920	4.3
2006	Not Preliminary	Dec	91,959	88,041	3,918	4.3
2005	Not Preliminary	Annual	88,632	84,872	3,760	4.2
2005	Not Preliminary	Jan	85,853	82,088	3,765	4.4
2005	Not Preliminary	Feb	86,626	82,939	3,687	4.3
2005	Not Preliminary	Mar	86,859	83,137	3,722	4.3
2005	Not Preliminary	Apr	87,722	84,185	3,537	4
2005	Not Preliminary	May	87,750	84,329	3,421	3.9
2005	Not Preliminary	Jun	88,769	85,043	3,726	4.2
2005	Not Preliminary	Jul	89,680	85,870	3,810	4.2
2005	Not Preliminary	Aug	90,239	86,368	3,871	4.3
2005	Not Preliminary	Sep	90,079	85,953	4,126	4.6
2005	Not Preliminary	Oct	89,886	85,865	4,021	4.5
2005	Not Preliminary	Nov	90,218	86,409	3,809	4.2
2005	Not Preliminary	Dec	89,900	86,274	3,626	4

Arizona Workforce Informer

Historical Data for Unemployment Rate in Santa Cruz County

Year	Prelim	Period	Labor Force	No.of Employed	No.of Unemployed	Unemployment Rate %
2009	Preliminary	Jan	18,357	16,308	2,049	11.2
2009	Preliminary	Feb	18,325	16,257	2,068	11.3
2009	Preliminary	Mar	17,971	15,912	2,059	11.5
2009	Preliminary	Apr	17,863	15,936	1,927	10.8
2009	Preliminary	May	17,940	15,847	2,093	11.7
2009	Preliminary	Jun	18,224	15,638	2,586	14.2
2008	Not Preliminary	Annual	18,179	16,361	1,818	10
2008	Not Preliminary	Jan	17,855	16,568	1,287	7.2
2008	Not Preliminary	Feb	17,560	16,385	1,175	6.7
2008	Not Preliminary	Mar	17,590	16,421	1,169	6.6
2008	Not Preliminary	Apr	17,562	16,478	1,084	6.2
2008	Not Preliminary	May	17,741	16,489	1,252	7.1
2008	Not Preliminary	Jun	18,265	16,626	1,639	9
2008	Not Preliminary	Jul	18,437	16,318	2,119	11.5
2008	Not Preliminary	Aug	18,955	16,305	2,650	14
2008	Not Preliminary	Sep	18,848	16,304	2,544	13.5
2008	Not Preliminary	Oct	18,710	16,109	2,601	13.9
2008	Not Preliminary	Nov	18,392	16,209	2,183	11.9
2008	Not Preliminary	Dec	18,236	16,121	2,115	11.6
2007	Not Preliminary	Annual	17,184	15,927	1,257	7.3
2007	Not Preliminary	Jan	17,498	16,365	1,133	6.5
2007	Not Preliminary	Feb	17,347	16,317	1,030	5.9
2007	Not Preliminary	Mar	17,171	16,201	970	5.6
2007	Not Preliminary	Apr	16,984	16,119	865	5.1
2007	Not Preliminary	May	16,984	16,127	857	5
2007	Not Preliminary	Jun	17,088	16,009	1,079	6.3
2007	Not Preliminary	Jul	16,887	15,380	1,507	8.9
2007	Not Preliminary	Aug	17,032	15,351	1,681	9.9
2007	Not Preliminary	Sep	17,033	15,335	1,698	10
2007	Not Preliminary	Oct	17,237	15,614	1,623	9.4
2007	Not Preliminary	Nov	17,543	16,247	1,296	7.4
2007	Not Preliminary	Dec	17,394	16,055	1,339	7.7
2006	Not Preliminary	Annual	16,638	15,399	1,239	7.4
2006	Not Preliminary	Jan	16,199	15,131	1,068	6.6
2006	Not Preliminary	Feb	16,304	15,287	1,017	6.2
2006	Not Preliminary	Mar	16,196	15,254	942	5.8
2006	Not Preliminary	Apr	16,257	15,368	889	5.5
2006	Not Preliminary	May	16,225	15,329	896	5.5
2006	Not Preliminary	Jun	16,461	15,284	1,177	7.2
2006	Not Preliminary	Jul	16,383	14,849	1,534	9.4
2006	Not Preliminary	Aug	16,848	15,243	1,605	9.5
2006	Not Preliminary	Sep	16,836	15,185	1,651	9.8
2006	Not Preliminary	Oct	17,055	15,467	1,588	9.3
2006	Not Preliminary	Nov	17,327	15,995	1,332	7.7
2006	Not Preliminary	Dec	17,571	16,397	1,174	6.7
2005	Not Preliminary	Annual	15,963	14,595	1,368	8.6
2005	Not Preliminary	Jan	15,806	14,650	1,156	7.3
2005	Not Preliminary	Feb	15,703	14,591	1,112	7.1
2005	Not Preliminary	Mar	15,723	14,625	1,098	7
2005	Not Preliminary	Apr	15,694	14,675	1,019	6.5
2005	Not Preliminary	May	15,742	14,687	1,055	6.7
2005	Not Preliminary	Jun	16,058	14,699	1,359	8.5
2005	Not Preliminary	Jul	16,700	14,966	1,734	10.4
2005	Not Preliminary	Aug	16,123	14,386	1,737	10.8
2005	Not Preliminary	Sep	15,968	14,112	1,856	11.6
2005	Not Preliminary	Oct	15,935	14,204	1,731	10.9
2005	Not Preliminary	Nov	15,963	14,573	1,390	8.7
2005	Not Preliminary	Dec	16,138	14,970	1,168	7.2

Arizona Workforce Informer

Historical Data for Unemployment Rate in Yavapai County

Year	Prelim	Period	Labor Force	No.of Employed	No.of Unemployed	Unemployment Rate %
2009	Preliminary	Jan	98,667	90,495	8,172	8.3
2009	Preliminary	Feb	98,832	90,523	8,309	8.4
2009	Preliminary	Mar	98,380	89,706	8,674	8.8
2009	Preliminary	Apr	98,563	90,512	8,051	8.2
2009	Preliminary	May	98,193	89,957	8,236	8.4
2009	Preliminary	Jun	98,862	89,740	9,122	9.2
2008	Not Preliminary	Annual	98,390	92,884	5,506	5.6
2008	Not Preliminary	Jan	96,763	92,198	4,565	4.7
2008	Not Preliminary	Feb	96,408	92,190	4,218	4.4
2008	Not Preliminary	Mar	97,213	92,800	4,413	4.5
2008	Not Preliminary	Apr	97,838	93,669	4,169	4.3
2008	Not Preliminary	May	98,250	93,632	4,618	4.7
2008	Not Preliminary	Jun	100,165	94,781	5,384	5.4
2008	Not Preliminary	Jul	100,393	94,531	5,862	5.8
2008	Not Preliminary	Aug	98,867	92,608	6,259	6.3
2008	Not Preliminary	Sep	99,354	93,002	6,352	6.4
2008	Not Preliminary	Oct	99,368	92,841	6,527	6.6
2008	Not Preliminary	Nov	98,200	91,636	6,564	6.7
2008	Not Preliminary	Dec	97,869	90,723	7,146	7.3
2007	Not Preliminary	Annual	97,767	94,191	3,576	3.7
2007	Not Preliminary	Jan	96,651	92,619	4,032	4.2
2007	Not Preliminary	Feb	96,727	93,243	3,484	3.6
2007	Not Preliminary	Mar	97,137	93,743	3,394	3.5
2007	Not Preliminary	Apr	97,376	94,128	3,248	3.3
2007	Not Preliminary	May	96,981	94,079	2,902	3
2007	Not Preliminary	Jun	98,981	95,538	3,443	3.5
2007	Not Preliminary	Jul	98,107	94,472	3,635	3.7
2007	Not Preliminary	Aug	97,358	93,867	3,491	3.6
2007	Not Preliminary	Sep	98,461	94,906	3,555	3.6
2007	Not Preliminary	Oct	99,134	95,407	3,727	3.8
2007	Not Preliminary	Nov	98,774	94,911	3,863	3.9
2007	Not Preliminary	Dec	97,515	93,378	4,137	4.2
2006	Not Preliminary	Annual	96,191	92,413	3,778	3.9
2006	Not Preliminary	Jan	92,578	88,373	4,205	4.5
2006	Not Preliminary	Feb	93,627	89,743	3,884	4.1
2006	Not Preliminary	Mar	94,317	90,616	3,701	3.9
2006	Not Preliminary	Apr	95,649	91,944	3,705	3.9
2006	Not Preliminary	May	95,188	91,780	3,408	3.6
2006	Not Preliminary	Jun	97,003	93,024	3,979	4.1
2006	Not Preliminary	Jul	95,859	91,866	3,993	4.2
2006	Not Preliminary	Aug	97,610	93,827	3,783	3.9
2006	Not Preliminary	Sep	98,386	94,541	3,845	3.9
2006	Not Preliminary	Oct	98,387	94,625	3,762	3.8
2006	Not Preliminary	Nov	98,279	94,684	3,595	3.7
2006	Not Preliminary	Dec	97,408	93,931	3,477	3.6
2005	Not Preliminary	Annual	90,975	86,989	3,986	4.4
2005	Not Preliminary	Jan	87,425	83,353	4,072	4.7
2005	Not Preliminary	Feb	88,151	84,166	3,985	4.5
2005	Not Preliminary	Mar	88,462	84,490	3,972	4.5
2005	Not Preliminary	Apr	90,317	86,474	3,843	4.3
2005	Not Preliminary	May	90,504	86,906	3,598	4
2005	Not Preliminary	Jun	92,301	88,266	4,035	4.4
2005	Not Preliminary	Jul	91,222	87,149	4,073	4.5
2005	Not Preliminary	Aug	92,423	88,242	4,181	4.5
2005	Not Preliminary	Sep	92,416	88,044	4,372	4.7
2005	Not Preliminary	Oct	93,503	89,302	4,201	4.5
2005	Not Preliminary	Nov	92,604	88,721	3,883	4.2
2005	Not Preliminary	Dec	92,376	88,755	3,621	3.9

UNSG 2.4 What is Mr. Radigan's position on how recovery of fixed costs should be allocated between fixed and variable rates?

Response:

Absent any rate impact and rate stability considerations, fixed charges, e.g. customer charges, should recover the cost to serve as indicated by a cost of service study. The variable rate is a valuable tool, particularly an inclining block rate structure, to assist customers in recognizing the need to conserve energy.

Respondent: Frank Radigan

Witness: Frank Radigan

EXHIBIT
UNSG 33
ADMITTED

UNSG 2.30 Referring to the statement on page 28, line 1, of Mr. Rigsby's Direct Testimony:

a. Does Mr. Rigsby believe that systematic risk is the only risk of importance to investors? Please explain.

b. Please provide any published research supporting the contention that systematic risk is the only risk of importance to investors.

Response:

a. No. The statement made by Mr. Rigsby is intended to point out one of the underlying assumptions that the CAPM model relies on Systematic risk might be one of a number of risk factors that individual investors consider to be important.

b. A large body of academic research has been published on the underlying assumptions of the CAPM model. Mr. Rigsby is unable to cite every piece of research that has challenged or supported the underlying assumption that systematic risk is the only risk of importance to investors. Having said that, RUCO offers the attached paper authored by Andre F. Perold which provides additional insight into the theoretical concept of the CAPM model.

Respondent: Bill Rigsby

Witness: Bill Rigsby

EXHIBIT
UNSG 34
ADMITTED

RUCO'S RESPONSE TO UNSG 2.30

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The Capital Asset Pricing Model

André F. Perold

A fundamental question in finance is how the risk of an investment should affect its expected return. The Capital Asset Pricing Model (CAPM) provided the first coherent framework for answering this question. The CAPM was developed in the early 1960s by William Sharpe (1964), Jack Treynor (1962), John Lintner (1965a, b) and Jan Mossin (1966).

The CAPM is based on the idea that not all risks should affect asset prices. In particular, a risk that can be diversified away when held along with other investments in a portfolio is, in a very real way, not a risk at all. The CAPM gives us insights about what kind of risk is related to return. This paper lays out the key ideas of the Capital Asset Pricing Model, places its development in a historical context, and discusses its applications and enduring importance to the field of finance.

Historical Background

In retrospect, it is striking how little we understood about risk as late as the 1960s—whether in terms of theory or empirical evidence. After all, stock and option markets had been in existence at least since 1602 when shares of the East India Company began trading in Amsterdam (de la Vega, 1688); and organized insurance markets had become well developed by the 1700s (Bernstein, 1996). By 1960, insurance businesses had for centuries been relying on diversification to spread risk. But despite the long history of actual risk-bearing and risk-sharing in organized financial markets, the Capital Asset Pricing Model was developed at a time when the theoretical foundations of decision making under uncertainty were relatively new and when basic empirical facts about risk and return in the capital markets were not yet known.

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Rigorous theories of investor risk preferences and decision-making under uncertainty emerged only in the 1940s and 1950s, especially in the work of von Neumann and Morgenstern (1944) and Savage (1954). Portfolio theory, showing how investors can create portfolios of individual investments to optimally trade off risk versus return, was not developed until the early 1950s by Harry Markowitz (1952, 1959) and Roy (1952).

Equally noteworthy, the empirical measurement of risk and return was in its infancy until the 1960s, when sufficient computing power became available so that researchers were able to collect, store and process market data for the purposes of scientific investigation. The first careful study of returns on stocks listed on the New York Stock Exchange was that of Fisher and Lorie (1964) in which they note: "It is surprising to realize that there have been no measurements of the rates of return on investments in common stocks that could be considered accurate and definitive." In that paper, Fisher and Lorie report average stock market returns over different holding periods since 1926, but not the standard deviation of those returns. They also do not report any particular estimate of the equity risk premium—that is, the average amount by which the stock market outperformed risk-free investments—although they do remark that rates of return on common stocks were "substantially higher than safer alternatives for which data are available." Measured standard deviations of broad stock market returns did not appear in the academic literature until Fisher and Lorie (1968). Carefully constructed estimates of the equity risk premium did not appear until Ibbotson and Sinquefield (1976) published their findings on long-term rates of return. They found that over the period 1926 to 1974, the (arithmetic) average return on the Standard and Poor's 500 index was 10.9 percent per annum, and the excess return over U.S. Treasury bills was 8.8 percent per annum.[1] The first careful study of the historical equity risk premium for UK stocks appeared in Dimson and Brealey (1978) with an estimate of 9.2 percent per annum over the period 1919–1977.

In the 1940s and 1950s, prior to the development of the Capital Asset Pricing Model, the reigning paradigm for estimating expected returns presupposed that the return that investors would require (or the "cost of capital") of an asset depended primarily on the manner in which that asset was financed (for example, Bierman and Smidt, 1966). There was a "cost of equity capital" and a "cost of debt capital," and the weighted average of these—based on the relative amounts of debt and equity financing—represented the cost of capital of the asset.

The costs of debt and equity capital were inferred from the long-term yields of those instruments. The cost of debt capital was typically assumed to be the rate of interest owed on the debt, and the cost of equity capital was backed out from the cash flows that investors could expect to receive on their shares in relation to the current price of the shares. A popular method of estimating the cost of equity this way was the Gordon and Shapiro (1956) model, in which a company's dividends are

[1] These are arithmetic average returns. Ibbotson and Sinquefield (1976) were also the first to report the term premium on long-term bonds: 1.1 percent per annum average return in excess of Treasury bills over the period 1926–1974.

assumed to grow in perpetuity at a constant rate g. In this model, if a firm's current dividend per share is D, and the stock price of the firm is P, then the cost of equity capital r is the dividend yield plus the dividend growth rate: $r = D/P + g$.[2]

From the perspective of modern finance, this approach to determining the cost of capital was anchored in the wrong place. At least in a frictionless world, the value of a firm or an asset more broadly does not depend on how it is financed, as shown by Modigliani and Miller (1958). This means that the cost of equity capital likely is determined by the cost of capital of the asset, rather than the other way around. Moreover, this process of inferring the cost of equity capital from future dividend growth rates is highly subjective. There is no simple way to determine the market's forecast of the growth rate of future cash flows, and companies with high dividend growth rates will be judged by this method to have high costs of equity capital. Indeed, the Capital Asset Pricing Model will show that there need not be any connection between the cost of capital and future growth rates of cash flows.

In the pre-CAPM paradigm, risk did not enter directly into the computation of the cost of capital. The working assumption was often that a firm that can be financed mostly with debt is probably safe and is thus assumed to have a low cost of capital; while a firm that cannot support much debt is probably risky and is thus assumed to command a high cost of capital. These rules-of-thumb for incorporating risk into discount rates were ad hoc at best. As Modigliani and Miller (1958) noted: "No satisfactory explanation has yet been provided . . . as to what determines the size of the risk [adjustment] and how it varies in response to changes in other variables."

In short, before the arrival of the Capital Asset Pricing Model, the question of how expected returns and risk were related had been posed, but was still awaiting an answer.

Why Investors Might Differ in Their Pricing of Risk

Intuitively, it would seem that investors should demand high returns for holding high-risk investments. That is, the price of a high-risk asset should be bid sufficiently low so that the future payoffs on the asset are high (relative to the price). A difficulty with this reasoning arises, however, when the risk of an investment depends on the manner in which it is held.

To illustrate, consider an entrepreneur who needs to raise $1 million for a risky new venture. There is a 90 percent chance that the venture will fail and end up worthless; and there is a 10 percent chance that the venture will succeed within a year and be worth $40 million. The expected value of the venture in one year is therefore $4 million, or $4 per share assuming that the venture will have a million shares outstanding.

Case I: If a single risk-averse individual were to fund the full $1 million—where

[2] The cost of equity capital in this model is the "internal rate of return," the discount rate that equates the present value of future cash flows to the current stock price. In the Gordon-Shapiro model, the projected dividend stream is D, $D(1 + g)$, $D(1 + g)^2 \ldots$ The present value of these cash flows when discounted at rate r is $D/(r - g)$, which when set equal to the current stock price, P, establishes $r = D/P + g$.

the investment would represent a significant portion of the wealth of that individual—the venture would have to deliver a very high expected return, say 100 percent. To achieve an expected return of 100 percent on an investment of $1 million, the entrepreneur would have to sell the investor a 50 percent stake: 500,000 shares at a price per share of $2.

Case II: If the funds could be raised from someone who can diversify across many such investments, the required return might be much lower. Consider an investor who has $100 million to invest in 100 ventures with the same payoffs and probabilities as above, except that the outcomes of the ventures are all independent of one another. In this case, the probability of the investor sustaining a large percentage loss is small—for example, the probability that all 100 ventures fail is a miniscule .003 percent ($= 0.9^{100}$)—and the diversified investor might consequently be satisfied to receive an expected return of only, say, 10 percent. If so, the entrepreneur would need to sell a much smaller stake to raise the same amount of money, here 27.5 percent (= $1.1 million/$4 million); and the investor would pay a higher price per share of $3.64 (= $1 million/275,000 shares).

Cases I and II differ only in the degree to which the investor is diversified; the stand-alone risk and the expected future value of any one venture is the same in both cases. Diversified investors face less risk per investment than undiversified investors, and they are therefore willing to receive lower expected returns (and to pay higher prices). For the purpose of determining required returns, the risks of investments therefore must be viewed in the context of the other risks to which investors are exposed. The CAPM is a direct outgrowth of this key idea.

Diversification, Correlation and Risk

The notion that diversification reduces risk is centuries old. In eighteenth-century English language translations of *Don Quixote*, Sancho Panza advises his master, "It is the part of a wise man to . . . not venture all his eggs in one basket." According to Herbison (2003), the proverb "Do not keep all your eggs in one basket" actually appeared as far back as Torriano's (1666) *Common Place of Italian Proverbs*.

However, diversification was typically thought of in terms of spreading your wealth across many *independent* risks that would cancel each other if held in sufficient number (as was assumed in the new ventures example). Harry Markowitz (1952) had the insight that, because of broad economic influences, risks across assets were correlated to a degree. As a result, investors could eliminate some but not all risk by holding a diversified portfolio. Markowitz wrote: "This presumption, that the law of large numbers applies to a portfolio of securities, cannot be accepted. The returns from securities are too intercorrelated. Diversification cannot eliminate all variance."

Markowitz (1952) went on to show analytically how the benefits of diversification depend on correlation. The correlation between the returns of two assets measures the degree to which they fluctuate together. Correlation coefficients range between −1.0 and 1.0. When the correlation is 1.0, the two assets are perfectly positively correlated. They move in the same direction and in fixed

proportions (plus a constant). In this case, the two assets are substitutes for one another. When the correlation is -1.0, the returns are perfectly negatively correlated meaning that when one asset goes up, the other goes down and in a fixed proportion (plus a constant). In this case, the two assets act to insure one another. When the correlation is zero, knowing the return on one asset does not help you predict the return on the other.

To show how the correlation among individual security returns affects portfolio risk, consider investing in two risky assets, A and B. Assume that the risk of an asset is measured by its standard deviation of return, which for assets A and B is denoted by σ_A and σ_B, respectively. Let ρ denote the correlation between the returns on assets A and B; let x be the fraction invested in Asset A and y $(= 1 - x)$ be the fraction invested in Asset B.

When the returns on assets within a portfolio are perfectly positively correlated $(\rho = 1)$, the portfolio risk is the weighted average of the risks of the assets in the portfolio. The risk of the portfolio then can be expressed as

$$\sigma_P = x\sigma_A + y\sigma_B.$$

The more interesting case is when the assets are not perfectly correlated $(\rho < 1)$. Then there is a nonlinear relationship between portfolio risk and the risks of the underlying assets. In this case, at least some of the risk from one asset will be offset by the other asset, so the standard deviation of the portfolio σ_P is always less than the weighted average of σ_A and σ_B.[3] Thus, the risk of a portfolio is less than the average risk of the underlying assets. Moreover, the benefit of diversification will increase the farther away that the correlation ρ is from 1.

These are Harry Markowitz's important insights: 1) that diversification does not rely on individual risks being uncorrelated, just that they be imperfectly correlated; and 2) that the risk reduction from diversification is limited by the extent to which individual asset returns are correlated. If Markowitz were restating Sancho Panza's advice, he might say: It is safer to spread your eggs among imperfectly correlated baskets than to spread them among perfectly correlated baskets.

Table 1 illustrates the benefits of diversifying across international equity markets. The table lists the world's largest stock markets by market capitalization as of December 31, 2003, the combination of which we will call the world equity market

[3] The portfolio standard deviation, σ_P, can be expressed in terms of the standard deviations of assets A and B and their correlation using the variance formula:

$$\sigma_P^2 = x^2\sigma_A^2 + y^2\sigma_B^2 + 2xy\rho\sigma_A\sigma_B.$$

This expression can be algebraically manipulated to obtain

$$\sigma_P^2 = (x\sigma_A + y\sigma_B)^2 - 2xy(1 - \rho)\sigma_A\sigma_B.$$

When $\rho = 1$, the final term disappears, giving the formula in the text. When $\rho < 1$, then the size of the second term will increase as ρ declines, and so the standard deviation of the portfolio will fall as ρ declines.

Table 1
Market Capitalizations and Historical Risk Estimates for 24 Countries, January 1994–December 2003

	Market Capitalization ($ Billions, 12/31/03)	*Capitalization Weight*	*S.D. of Return*	*Beta vs. WEMP*	*Correlation vs. WEMP*
U.S.	$14,266	47.8%	16.1%	1.00	0.95
Japan	2,953	9.9%	22.3%	0.83	0.57
UK	2,426	8.1%	14.3%	0.78	0.83
France	1,403	4.7%	19.3%	1.00	0.79
Germany	1,079	3.6%	21.7%	1.10	0.77
Canada	910	3.0%	19.9%	1.13	0.87
Switzerland	727	2.4%	17.1%	0.73	0.65
Spain	726	2.4%	21.5%	0.92	0.65
Hong Kong	715	2.4%	29.2%	1.33	0.70
Italy	615	2.1%	23.9%	0.90	0.58
Australia	586	2.0%	18.4%	0.93	0.77
China	513	1.7%	43.3%	1.26	0.45
Taiwan	379	1.3%	33.0%	1.15	0.53
Netherlands	368	1.2%	19.5%	1.02	0.79
Sweden	320	1.1%	24.3%	1.25	0.78
South Korea	298	1.0%	47.7%	1.55	0.50
India	279	0.9%	26.7%	0.63	0.36
South Africa	261	0.9%	26.9%	1.09	0.62
Brazil	235	0.8%	43.6%	1.81	0.63
Russia	198	0.7%	76.9%	2.34	0.47
Belgium	174	0.6%	17.2%	0.65	0.58
Malaysia	168	0.6%	38.6%	0.81	0.32
Singapore	149	0.5%	28.6%	1.04	0.56
Mexico	123	0.4%	35.1%	1.40	0.61
WEMP	$29,870	100%	15.3%	1.00	1.00
S.D. of WEMP assuming perfect correlation			19.9%		
S.D. of WEMP assuming zero correlation			8.4%		

Notes: WEMP stands for World Equity Market Portfolio. S.D. is standard deviation expressed on an annualized basis. Calculations are based on historical monthly returns obtained from Global Financial Data Inc.

portfolio, labeled in the table as WEMP. The capitalization of the world equity market portfolio was about $30 trillion—comprising over 95 percent of all publicly traded equities—with the United Statese representing by far the largest fraction. Table 1 includes the standard deviation of monthly total returns for each country over the ten-year period ending December 31, 2003, expressed on an annualized basis.

Assuming that the historical standard deviations and correlations of return are good estimates of future standard deviations and correlations, we can use this data to calculate that the standard deviation of return of the WEMP—given the capitalization weights as of December 2003—is 15.3 percent per annum. If the country returns were all perfectly correlated with each other, then the standard deviation of the WEMP would be the capitalization-weighted average of the standard deviations,

which is 19.9 percent per annum. The difference of 4.6 percent per annum represents the diversification benefit—the risk reduction stemming from the fact that the world's equity markets are imperfectly correlated. Also shown in Table 1 is that the standard deviation of the WEMP would be only 8.4 percent per annum if the country returns were uncorrelated with one another. The amount by which this figure is lower than the actual standard deviation of 15.3 percent per annum is a measure of the extent to which the world's equity markets share common influences.

Portfolio Theory, Riskless Lending and Borrowing and Fund Separation

To arrive at the CAPM, we need to examine how imperfect correlation among asset returns affects the investor's tradeoff between risk and return. While risks combine nonlinearly (because of the diversification effect), expected returns combine linearly. That is, the expected return on a portfolio of investments is just the weighted average of the expected returns of the underlying assets. Imagine two assets with the same expected return and the same standard deviation of return. By holding both assets in a portfolio, one obtains an expected return on the portfolio that is the same as either one of them, but a portfolio standard deviation that is lower than any one of them individually. Diversification thus leads to a reduction in risk *without any sacrifice in expected return.*

Generally, there will be many combinations of assets with the same portfolio expected return but different portfolio risk; and there will be many combinations of assets with the same portfolio risk but different portfolio expected return. Using optimization techniques, we can compute what Markowitz coined the "efficient frontier." For each level of expected return, we can solve for the portfolio combination of assets that has the lowest risk. Or for each level of risk, we can solve for the combination of assets that has the highest expected return. The efficient frontier consists of the collection of these optimal portfolios, and each investor can choose which of these best matches their risk tolerance.

The initial development of portfolio theory assumed that all assets were risky. James Tobin (1958) showed that when investors can borrow as well as lend at the risk-free rate, the efficient frontier simplifies in an important way. (A "risk-free" instrument pays a fixed real return and is default free. U.S. Treasury bonds that adjust automatically with inflation—called Treasury inflation-protected instruments, or TIPS—and short-term U.S. Treasury bills are considered close approximations of risk-free instruments.)

To see how riskless borrowing and lending affects investors' decision choices, consider investing in the following three instruments: risky assets *M* and *H*, and the riskless asset, where the expected returns and risks of the assets are shown in Table 2. Suppose first that you had the choice of investing all of your wealth in *just one* of these assets. Which would you choose? The answer depends on your risk tolerance. Asset *H* has the highest risk and also the highest expected return. You would choose

Table 2
How Riskless Borrowing and Lending Affect Investors' Choices

	Expected return	*Risk (S.D.)*
Riskless asset	5% (r_f)	0%
Asset M	10% (E_M)	20% (σ_M)
Asset H	12% (E_H)	40% (σ_H)

Asset H if you had a high tolerance for risk. The riskless asset has no risk but also the lowest expected return. You would choose to lend at the risk-free rate if you had a very low tolerance for risk. Asset M has an intermediate risk and expected return, and you would choose this asset if you had a moderate tolerance for risk.

Suppose next that you can borrow and lend at the risk-free rate, that you wish to invest some of your wealth in Asset H and the balance in riskless lending or borrowing. If x is the fraction of wealth invested in Asset H, then $1 - x$ is the fraction invested in the risk-free asset. When $x < 1$, you are lending at the risk-free rate; when $x > 1$, you are borrowing at the risk-free rate. The expected return of this portfolio is $(1 - x)r_f + xE_H$, which equals $r_f + x(E_H - r_f)$, and the risk of the portfolio is $x\sigma_H$. The risk of the portfolio is proportional to the risk of Asset H, since Asset H is the only source of risk in the portfolio.

Risk and expected return thus both combine *linearly*, as shown graphically in Figure 1. Each point on the line connecting the risk-free asset to Asset H represents a particular allocation (x) to Asset H with the balance in either risk-free lending or risk-free borrowing. The slope of this line is called the Sharpe Ratio—the risk premium of Asset H divided by the risk of Asset H:

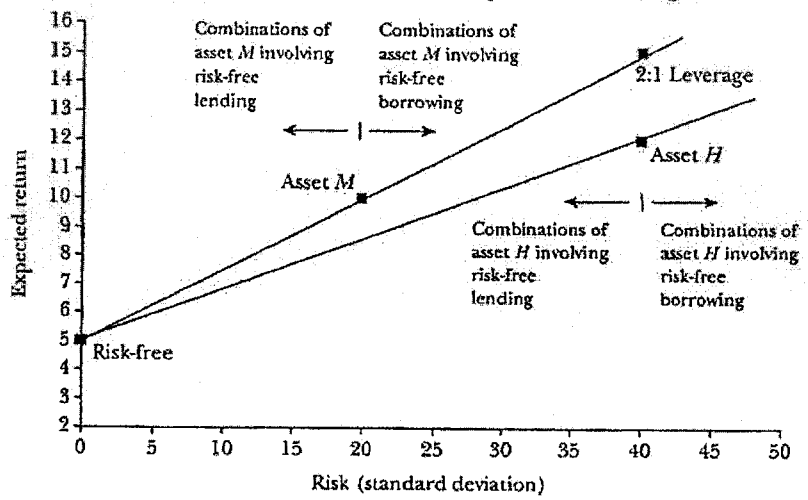
$$\text{Sharpe Ratio} = (E_H - r_f)/\sigma_H.$$

The Sharpe Ratio of Asset H evaluates to 0.175 (= (12 percent − 5 percent)/ 40 percent) and all combinations of Asset H with risk-free borrowing or lending have this same Sharpe Ratio.

Also shown in Figure 1 are the risks and expected returns that can be achieved by combining Asset M with riskless lending and borrowing. The Sharpe Ratio of Asset M is 0.25, which is higher than that of Asset H, and any level of risk and return that can be obtained by investing in Asset H along with riskless lending or borrowing is dominated by some combination of Asset M and riskless lending or borrowing. For example, for the same risk as Asset H, you can obtain a higher expected return by investing in Asset M with 2:1 leverage. As shown in Figure 1, the expected return of a 2:1 leveraged position in Asset M is 15 percent (that is, (2 × 10 percent) − (1 × 5 percent)), which is higher than the 12 percent expected return of Asset H. If you could hold only one risky asset along with riskless lending or borrowing, it unambiguously would be Asset M.

Being able to lend and borrow at the risk-free rate thus dramatically changes

Figure 1
Combining a Risky Asset with Risk-Free Lending and Borrowing



our investment choices. The asset of choice—if you could choose only one risky asset—is the one with the highest Sharpe Ratio. Given this choice of risky asset, you need to make a second decision, which is how much of it to hold in your portfolio. The answer to the latter question depends on your risk tolerance.

Figure 2 illustrates the approach in the case where we can invest in combinations of two risky assets, *M* and *H*, plus riskless lending and borrowing. The correlation between the returns of assets *M* and *H* is assumed to be zero. In the figure, the curve connecting assets *M* and *H* represents all expected return/standard deviation pairs that can be attained through combinations of assets *M* and *H*. The combination of assets *M* and *H* that has the highest Sharpe Ratio is 74 percent in Asset *M* and 26 percent in Asset *H* (the tangency point). The expected return of this combination is 10.52 percent, and the standard deviation is 18.09 percent. The Sharpe Ratio evaluates to 0.305, which is considerably higher than the Sharpe Ratios of assets *M* and *H* (0.25 and 0.175, respectively). Investors who share the same estimates of expected return and risk all will locate their portfolios on the tangency line connecting the risk-free asset to the frontier. In particular, they all will hold assets *M* and *H* in the proportions 74/26.

The optimal portfolio of many risky assets can be found similarly. Figure 3 offers a general illustration. Use Markowitz's algorithm to obtain the efficient frontier of portfolios of risky assets. Find the portfolio on the efficient frontier that has the highest Sharpe Ratio, which will be the point where a ray stretching up from the risk-free point is just tangent to the efficient frontier. Then, in accordance with your risk tolerance, allocate your wealth between this highest Sharpe Ratio portfolio and risk-free lending or borrowing.

This characterization of the efficient frontier is referred to as "fund separation." Investors with the same beliefs about expected returns, risks and correlations all will invest in the portfolio or "fund" of risky assets that has the highest Sharpe

Figure 2
Efficient Frontier with Two Risky Assets

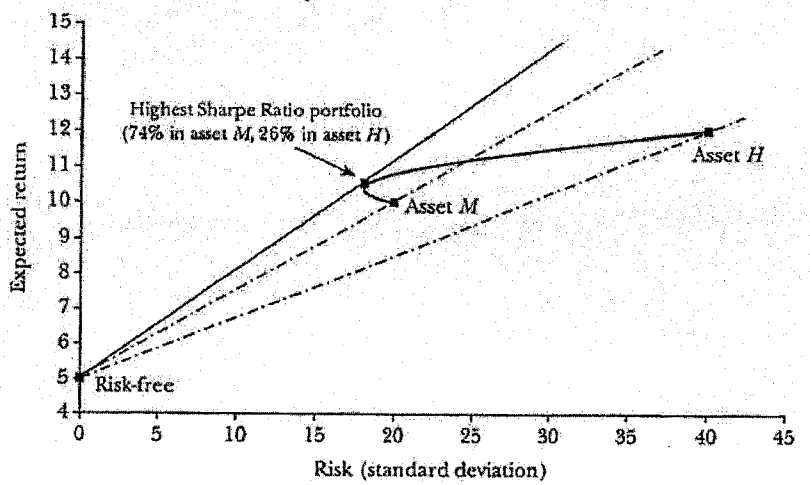
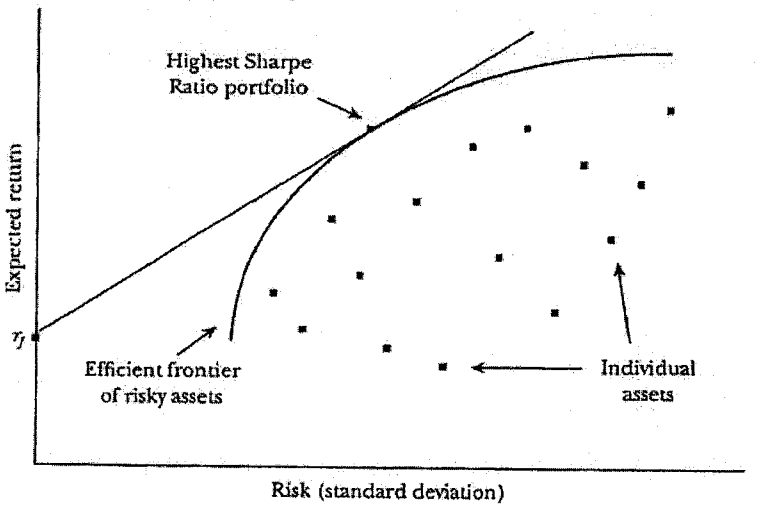


Figure 3
Efficient Frontier with Many Risky Assets



Ratio, but they will differ in their allocations between this fund and risk-free lending or borrowing based on their risk tolerance. Notice in particular that the composition of the optimal portfolio of risky assets does *not* depend on the investor's tolerance for risk.

Market-Determined Expected Returns and Stand-Alone Risk

Portfolio theory prescribes that investors choose their portfolios on the efficient frontier, given their beliefs about expected returns and risks. The Capital

Asset Pricing Model, on the other hand, is concerned with the pricing of assets in equilibrium. CAPM asks: What are the implications for asset prices if everyone heeds this advice? In equilibrium, all assets must be held by someone. For the market to be in equilibrium, the expected return of each asset must be such that investors collectively decide to hold exactly the supply of shares of the asset. The Capital Asset Pricing Model will tell us how investors determine those expected returns—and thereby asset prices—as a function of risk.

In thinking about how expected return and risk might be related, let us ask whether, *as a rule*, the expected return on an investment could possibly be a function of its stand-alone risk (measured by standard deviation of return). The answer turns out to be "no." Consider the shares of two firms with the same stand-alone risk. If the expected return on an investment was determined solely by its stand-alone risk, the shares of these firms would have the same expected return, say 10 percent. Any portfolio combination of the two firms would also have an expected return of 10 percent (since the expected return of a portfolio of assets is the weighted average of the expected returns of the assets that comprise the portfolio). However, if the shares of the firms are not perfectly correlated, then a portfolio invested in the shares of the two firms will be less risky than either one stand-alone. Therefore, if expected return is a function solely of stand-alone risk, then the expected return of this portfolio must be less than 10 percent, contradicting the fact that the expected return of the portfolio is 10 percent. Expected returns, therefore, cannot be determined solely by stand-alone risk.

Accordingly, any relationship between expected return and risk must be based on a measure of risk that is not stand-alone risk. As we will soon see, that measure of risk is given by the incremental risk that an asset provides when added to a portfolio, as discussed in the next section.

Improving the Sharpe Ratio of a Portfolio

Suppose you were trying to decide whether to add a particular stock to your investment portfolio of risky assets. If you could borrow and lend at the risk-free rate, you would add the stock if it improved the portfolio's Sharpe Ratio. It turns out there is a simple rule to guide the decision—a rule that can be derived by understanding the two special cases: 1) when the additional stock is uncorrelated with the existing portfolio, and 2) when the additional stock is perfectly correlated with the existing portfolio. The rule will lead us directly to the equilibrium risk-return relationship specified by the Capital Asset Pricing Model.

In what follows, it will be helpful to think in terms of "excess return," the return of an instrument in excess of the risk-free rate. The expected excess return is called the risk premium.

Adding a Stock that is Uncorrelated with the Existing Portfolio

When should a portfolio be diversified into an uncorrelated stock? If the excess returns on the stock and existing portfolio are uncorrelated, adding a small

amount of the stock has almost no effect on the risk of the portfolio.[4] At the margin, therefore, the stock is a substitute for investing in the risk-free asset. Including the stock will increase the portfolio's Sharpe Ratio if the stock's expected return E_S exceeds the risk-free rate r_f. Said another way, the additional stock should be included in the portfolio if its risk premium $E_S - r_f$ is positive.

Adding a Stock that is Perfectly Correlated with the Existing Portfolio

If the stock and portfolio excess returns are perfectly correlated, investing in the stock becomes a substitute for investing in the portfolio itself. To see this, recall that a perfect correlation means that the stock and the portfolio excess returns move together in a fixed ratio plus a constant. The fixed ratio is called beta, denoted by β, and the constant is called alpha, denoted by α. In other words, the excess return of the stock is equal to alpha plus beta times the excess return of the portfolio. It also follows that the *expected* excess return of the stock is alpha plus beta times the *expected* excess return on the portfolio—that is, $E_S - r_f = \alpha + \beta(E_P - r_f)$. The constant alpha is therefore given by the difference between the risk premium of the stock and beta times the risk premium of the portfolio. Since the stock and the portfolio move together in a fixed proportion, beta is given by the ratio of stock to portfolio standard deviations of excess return: $\beta = \sigma_S/\sigma_P$.

Compare now an investment of \$1 in the stock with the following "mimicking" strategy: invest $\$\beta$ in the portfolio and the balance $\$(1 - \beta)$ in the risk-free asset, assuming that $\beta < 1$. For example, if beta is 0.5, then investing \$0.50 in the portfolio and \$0.50 in the riskless asset is a strategy that will gain or lose 0.5 percent of excess return for every 1 percent gain or loss in the portfolio excess return. The excess return of the mimicking strategy is beta times the excess return of the portfolio. The mimicking strategy will behave just like the stock up to the constant difference alpha. The mimicking strategy can be thought of as a "stock" with the given beta but an alpha of zero.

Similarly, if $\beta > 1$, the mimicking strategy involves investing $\$\beta$ in the portfolio of which $\$(\beta - 1)$ is borrowed at the riskless rate. For example, if beta is 3, the mimicking portfolio involves investing \$3 in the portfolio of which \$2 is borrowed at the risk-free rate. This strategy will gain or lose 3 percent of excess return for every 1 percent gain or loss in the portfolio excess return. Again, the mimicking strategy will behave just like the stock up to the constant difference alpha.

When should a stock be added to the portfolio if its return is perfectly correlated with that of the portfolio? Since, up to the constant alpha, the stock is just a substitute for the portfolio, adding \$1 of the stock to the portfolio amounts to owning $\$\beta$ more of the portfolio. But owning more of the portfolio by itself does not change its Sharpe Ratio. Therefore, adding the stock will increase the portfolio's Sharpe Ratio if the

[4] Assume that you have \$1 of wealth invested in the portfolio. Then, adding an investment of $\$x$ in shares of the stock increases the portfolio variance to $\sigma_P^2 + x^2\sigma_S^2$, where σ_P^2 is the variance of the portfolio and $x^2\sigma_S^2$ is the variance of the additional stock, weighted by the number of dollars invested in the stock. Remember, the variance of a combination of uncorrelated risks equals the sum of the variances of the individual risks. The increase in portfolio risk (standard deviation as well as variance) is proportional to x^2, which implies that the change in portfolio risk is negligible for small x. The $\$x$ needed to purchase the shares can come from holding less of the risk-free asset or by borrowing at the risk-free rate.

stock's expected excess return exceeds that of the mimicking portfolio. This occurs if $\alpha > 0$ or equivalently if $E_S - r_f > \beta(E_P - r_f)$, meaning that the stock's risk premium must exceed beta times the portfolio risk premium.

The General Case: Adding a Stock that is Imperfectly Correlated with the Existing Portfolio

Suppose next that the returns on the stock and the portfolio are correlated to some degree ($0 < \rho < 1$). In this case, the stock's return can be separated into a return component that is *perfectly correlated* with the portfolio and a return component that is *uncorrelated* with the portfolio. Since the standard deviation of the stock is σ_S, the standard deviation of the perfectly correlated component of the stock's return is $\rho\sigma_S$.[5] Thus, the beta of the perfectly correlated component of the stock's excess return to the portfolio's excess return is given by the ratio of standard deviations: $\beta = \rho\sigma_S/\sigma_P$.

As just discussed, the component of the stock's return that is perfectly correlated with the portfolio is a substitute for the portfolio itself and can be mimicked through an investment of β in the portfolio and $(1 - \beta)$ in the riskless asset. The component of the stock's excess return that is uncorrelated with the portfolio can, at the margin, be diversified away and will thus have no effect on the risk of the portfolio. This component of return can be mimicked through an investment in the risk-free asset. We can therefore conclude that adding the stock to the portfolio will improve the Sharpe Ratio if the stock's risk premium exceeds the sum of the risk premia of the two mimicking portfolios: $\beta(E_P - r_f)$ for the perfectly correlated return component and zero for the uncorrelated return component.

This insight establishes a rule for improving the portfolio. Adding a marginal share of stock to a portfolio will increase the portfolio's Sharpe Ratio if the stock's alpha is positive, that is, if its risk premium satisfies

$$E_S - r_f > \beta(E_P - r_f).$$

Conversely, selling short a marginal share of the stock will increase the portfolio's Sharpe Ratio if the alpha is negative, $E_S - r_f < \beta(E_P - r_f)$. The portfolio has the highest attainable Sharpe Ratio if $E_S - r_f = \beta(E_P - r_f)$ for every stock—that is, if the risk premium for each stock is equal to beta times the risk premium for the portfolio as a whole.

The Capital Asset Pricing Model

The rule for improving the Sharpe Ratio of a portfolio allows us to derive the Capital Asset Pricing Model in a straightforward and intuitive way. We begin with four assumptions. First, investors are risk averse and evaluate their investment portfolios

[5] The correlation coefficient ρ is the "R" in "R-squared"—the fraction of the stock's variance that is attributable to movements in the portfolio. If $\rho < 0$, the standard deviation of the perfectly correlated component is $|\rho|\sigma_S$.

solely in terms of expected return and standard deviation of return measured over the same single holding period. Second, capital markets are perfect in several senses: all assets are infinitely divisible; there are no transactions costs, short selling restrictions or taxes; information is costless and available to everyone; and all investors can borrow and lend at the risk-free rate. Third, investors all have access to the same investment opportunities. Fourth, investors all make the same estimates of individual asset expected returns, standard deviations of return and the correlations among asset returns.

These assumptions represent a highly simplified and idealized world, but are needed to obtain the CAPM in its basic form. The model has been extended in many ways to accommodate some of the complexities manifest in the real world. But under these assumptions, given prevailing prices, investors all will determine the same highest Sharpe Ratio portfolio of risky assets. Depending on their risk tolerance, each investor will allocate a portion of wealth to this optimal portfolio and the remainder to risk-free lending or borrowing. Investors all will hold risky assets in the same relative proportions.

For the market to be in equilibrium, the price (that is, the expected return) of each asset must be such that investors collectively decide to hold exactly the supply of the asset. If investors all hold risky assets in the same proportions, those proportions must be the proportions in which risky assets are held in the market portfolio—the portfolio comprised of all available shares of each risky asset. In equilibrium, therefore, the portfolio of risky assets with the highest Sharpe Ratio must be the market portfolio.

If the market portfolio has the highest attainable Sharpe Ratio, there is no way to obtain a higher Sharpe Ratio by holding more or less of any one asset. Applying the portfolio improvement rule, it follows that the risk premium of each asset must satisfy $E_S - r_f = \beta(E_M - r_f)$, where E_S and E_M are the expected return on the asset and the market portfolio, respectively, and β is the sensitivity of the asset's return to the return on the market portfolio.

We have just established the Capital Asset Pricing Model: In equilibrium, the expected return of an asset is given by

$$E_S = r_f + \beta(E_M - r_f).$$

This formula is the one that Sharpe, Treynor, Lintner and Mossin successfully set out to find. It is the relationship between expected return and risk that is consistent with investors behaving according to the prescriptions of portfolio theory. If this rule does not hold, then investors will be able to outperform the market (in the sense of obtaining a higher Sharpe Ratio) by applying the portfolio improvement rule, and if sufficiently many investors do this, stock prices will adjust to the point where the CAPM becomes true.

Another way of expressing the CAPM equation is

$$\text{Sharpe Ratio of Asset } S = \rho \times \text{Sharpe Ratio of the Market Portfolio.}^{6}$$

[6] Using the fact that that $\beta = \rho\sigma_S/\sigma_M$, the equation $E_S = r_f + \beta(E_M - r_f)$ can be rearranged to give $(E_S - r_f)/\sigma_S = \rho(E_M - r_f)/\sigma_M$, which is the expression in the text.

In other words, in equilibrium, the Sharpe Ratio of any asset is no higher than the Sharpe Ratio of the market portfolio (since $\rho \leq 1$). Moreover, assets having the same correlation with the market portfolio will have the same Sharpe Ratio.

The Capital Asset Pricing Model tells us that to calculate the expected return of a stock, investors need know two things: the risk premium of the overall equity market $E_M - r_f$ (assuming that equities are the only risky assets) and the stock's beta versus the market. The stock's risk premium is determined by the component of its return that is perfectly correlated with the market—that is, the extent to which the stock is a substitute for investing in the market. The component of the stock's return that is uncorrelated with the market can be diversified away and does not command a risk premium.

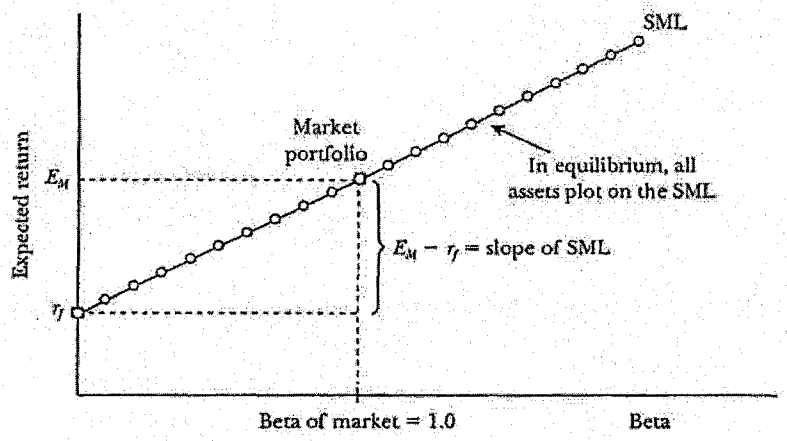
The Capital Asset Pricing Model has a number of important implications. First, perhaps the most striking aspect of the CAPM is what the expected return of an asset does *not* depend on. In particular, the expected return of a stock does not depend on its stand-alone risk. It is true that a high beta stock will tend to have a high stand-alone risk because a portion of a stock's stand-alone risk is determined by its beta, but a stock need not have a high beta to have a high stand-alone risk. A stock with high stand-alone risk therefore will only have a high expected return to the extent that its stand-alone risk is derived from its sensitivity to the broad stock market.

Second, beta offers a method of measuring the risk of an asset that cannot be diversified away. We saw earlier that any risk measure for determining expected returns would have to satisfy the requirement that the risk of a portfolio is the weighted average of the risks of the holdings in the portfolio. Beta satisfies this requirement. For example, if two stocks have market betas of 0.8 and 1.4, respectively, then the market beta of a 50/50 portfolio of these stocks is 1.1, the average of the two stock betas. Moreover, the capitalization weighted average of the market betas of all stocks is the beta of the market versus itself. The average stock therefore has a market beta of 1.0.

On a graph where the risk of an asset as measured by beta is on the horizontal axis and return is on the vertical axis, all securities lie on a single line—the so-called Securities Market Line shown in Figure 4. If the market is in equilibrium, all assets must lie on this line. If not, investors will be able to improve upon the market portfolio and obtain a higher Sharpe Ratio. In contrast, Figure 3 presented earlier measured risk on the horizontal axis as stand-alone risk, the standard deviation of each stock, and so stocks were scattered over the diagram. But remember that not all of the stand-alone risk of an asset is priced into its expected return, just that portion of its risk, $\rho\sigma_S$, that is correlated with the market portfolio.

Third, in the Capital Asset Pricing Model, a stock's expected return does not depend on the growth rate of its expected future cash flows. To find the expected return of a company's shares, it is thus not necessary to carry out an extensive financial analysis of the company and to forecast its future cash flows. According to the CAPM, all we need to know about the specific company is the beta of its shares, a parameter that is usually much easier to estimate than the expected future cash flows of the firm.

Figure 4
The Securities Market Line (SML)



Is the CAPM Useful?

The Capital Asset Pricing Model is an elegant theory with profound implications for asset pricing and investor behavior. But how useful is the model given the idealized world that underlies its derivation? There are several ways to answer this question. First, we can examine whether real world asset prices and investor portfolios conform to the predictions of the model, if not always in a strict quantitative sense, and least in a strong qualitative sense. Second, even if the model does not describe our current world particularly well, it might predict future investor behavior—for example, as a consequence of capital market frictions being lessened through financial innovation, improved regulation and increasing capital market integration. Third, the CAPM can serve as a benchmark for understanding the capital market phenomena that cause asset prices and investor behavior to deviate from the prescriptions of the model.

Suboptimal Diversification

Consider the CAPM prediction that investors all will hold the same (market) portfolio of risky assets. One does not have to look far to realize that investors do not hold identical portfolios, which is not a surprise since taxes alone will cause idiosyncratic investor behavior. For example, optimal management of capital gains taxes involves early realization of losses and deferral of capital gains, and so taxable investors might react very differently to changes in asset values depending on when they purchased the asset (Constantinides, 1983). Nevertheless, it will still be a positive sign for the model if most investors hold broadly diversified portfolios. But even here the evidence is mixed. On one hand, popular index funds make it possible for investors to obtain diversification at low cost. On the other hand, many workers hold concentrated ownership of company stock in employee retirement savings plans and many executives hold concentrated ownership of company stock options.

One of the most puzzling examples of suboptimal diversification is the so-

called home bias in international investing. In almost all countries, foreign ownership of assets is low, meaning that investors tend to hold predominantly home country assets. For example, in 2003, foreign ownership accounted for only 10 percent of publicly traded U.S. equities and 21 percent of publicly traded Japanese equities. Japanese investor portfolios therefore deviate significantly from the world equity market portfolio: they own the vast majority of their home country equities, but only a tiny share of U.S. equities. By contrast, and as shown in Table 1, an investor holding the world equity market portfolio would be invested 48 percent in U.S. equities and only 10 percent in Japanese equities.

Why is suboptimal diversification so pervasive? Common explanations are that obtaining broad diversification can be costly, in terms of direct expenses and taxes, and that investors are subject to behavioral biases and lack of sophistication. None of these reasons, if valid, would mean that the CAPM is not useful. The CAPM tells us that investors pay a price for being undiversified in that they are taking risks for which they are not being compensated. Thus, there exists the potential for portfolio improvement, which in turn creates opportunities for investor education and financial innovation. Indeed, foreign ownership of equities in many countries has more than doubled over the last 20 years, most likely due to the increased availability of low-cost vehicles to invest globally and greater investor appreciation of the need for diversification. Investors today seem to be much better diversified than in decades past, a trend that appears likely to continue.

Performance Measurement

One of the earliest applications of the Capital Asset Pricing Model was to performance measurement of fund managers (Treynor, 1965; Sharpe, 1966; Jensen, 1968). Consider two funds, *A* and *B*, that are actively managed in the hope of outperforming the market. Suppose that the funds obtained returns of 12 percent and 18 percent, respectively, during a period when the risk-free rate was 5 percent and the overall market returned 15 percent. Assume further that the standard deviation of funds *A* and *B* were 40 percent per annum and 30 percent per annum, respectively. Which fund had the better performance?

At first glance, fund *A* had greater risk and a lower return than fund *B*, so fund *B* would appear to have been the better performing fund. However, we know from the CAPM that focusing on stand-alone risk is misleading if investors can hold diversified portfolios. To draw a firmer conclusion, we need to know how these funds are managed: Suppose that fund *A* consists of a high-risk but "market-neutral" portfolio that has long positions in some shares and short positions in others, with a portfolio beta of zero. Fund *B*, on the other hand, invests in selected high beta stocks, with a portfolio beta of 1.5.

Instead of investing in funds *A* and/or *B*, investors could have held corresponding mimicking or "benchmark" portfolios. For fund *A*, since its beta is zero, the benchmark portfolio is an investment in the risk-free asset; for fund *B*, the benchmark is a position in the market portfolio leveraged 1.5:1 with borrowing at the risk-free rate. The benchmark portfolios respectively would have returned 5 percent and 20 percent (= 5 percent + 1.5 × (15 percent − 5 percent)). Fund

Table 3
Evaluating Portfolio Managers with the CAPM

	Return	*Risk (S.D.)*	*Beta*	*Alpha*
Riskless asset	5%	0%	0.0	0%
Market portfolio	15%	20%	1.0	0%
Fund *A*	12%	40%	0.0	7%
Fund *B*	18%	30%	1.5	−2%

A thus outperformed its benchmark by 7 percent, while fund *B* underperformed its benchmark by 2 percent, as shown in Table 3.

In terms of the CAPM framework, funds *A* and *B* had alphas of 7 percent and −2 percent, respectively, where alpha is the difference between a fund's performance and that predicted given the beta of the fund. Appropriately risk adjusted, fund *A*'s performance (alpha = 7 percent) exceeded that of fund *B* (alpha = −2 percent). An investor who held the market portfolio would, at the margin, have obtained a higher return *for the same risk* by allocating money to fund *A* rather than to fund *B*.[7]

The key idea here is that obtaining high returns by owning high beta stocks does not take skill, since investors can passively create a high beta portfolio simply through a leveraged position in the market portfolio. Obtaining high returns with low beta stocks is much harder, however, since such performance cannot be replicated with a passive strategy. Investors therefore need to assess performance based on returns that have been appropriately risk adjusted. The CAPM provides a clear framework for thinking about this issue.

The CAPM and Discounted Cash Flow Analysis

According to the CAPM, the appropriate discount rate for valuing the expected future cash flows of a company or of a new investment project is determined by the risk-free rate, the market risk premium and the beta versus the market of the company or project. Accuracy in estimating these parameters matters greatly for real world decisionmaking since, for long-dated cash flows, an error in the discount rate is magnified manyfold when calculating the net present value.

Beta is usually estimated with use of linear regression analysis applied to historical stock market returns data. Beta can in many circumstances be accurately measured this way even over a relatively short period of time, provided that there is sufficient high-frequency data. When the company or project being valued is not publicly traded or there is no relevant return history, it is customary to infer beta from comparable entities whose betas can be estimated. But measurement issues can arise even if the availability of market returns data is not an issue, for example when the covariance with

[7] This assumes that the beta of the overall portfolio is held constant—by holding more of the market portfolio if money is allocated to fund *A* and less of the market portfolio if money is allocated to fund *B*.

the market is time varying and when local stock market indexes are used as proxies for the broad market portfolio because the latter is not well specified.

The hardest of all parameters to estimate is usually the market risk premium. The historical risk premium is estimated from the average of past returns and, unlike variance-related measures like beta, average returns are very sensitive to the beginning and ending level of stock prices. The risk premium must therefore be measured over long periods of time, and even this may not be sufficient if the risk premium varies over time.

None of these measurement questions poses a problem for the CAPM per se, however. The market risk premium is common to all models of cash flow valuation, and its estimation needs to be performed regardless of the difficulty of the task. Provided that the CAPM is the "right" model, beta too needs to be estimated, irrespective of difficulty.

Extensions of the CAPM

The Capital Asset Pricing Model has been extended in a variety of ways. Some of the best-known extensions include allowing heterogenous beliefs (Lintner, 1969; Merton, 1987); eliminating the possibility of risk-free lending and borrowing (Black, 1972); having some assets be nonmarketable (Mayers, 1973); allowing for multiple time periods and investment opportunities that change from one period to the next (Merton, 1973; Breeden, 1979); extensions to international investing (Solnik, 1974; Stulz, 1981; Adler and Dumas, 1983); and employing weaker assumptions by relying on arbitrage pricing (Ross, 1976). In most extensions of the CAPM, no single portfolio of risky assets is optimal for everyone. Rather, investors allocate their wealth differentially among several risky portfolios, which across all investors aggregate to the market portfolio.

To illustrate, consider the International Capital Asset Pricing Model. This model takes into account that investors have consumption needs particular to the country in which they are resident. Thus, British investors will worry about the purchasing power of pounds while American investors worry about the purchasing power of dollars, which means that British and American investors will differently assess the incremental contribution that any particular asset makes to portfolio risk. As a result, they will hold somewhat different portfolios.[8] In the basic CAPM, investors care about only one risk factor—the overall market. In this international version of the model, they are also concerned about real currency fluctuations. This insight leads to a model of expected returns involving not only the beta of an asset versus the overall market, but also the betas of the asset versus currency movements and any other risk that is viewed differently by different investor segments.

Almost all variants of the CAPM have a multi-beta expression for expected

[8] British investors who own American assets will hedge a portion of their real pound/dollar exchange rate exposure by borrowing in dollars and lending in pounds, and American investors who own British assets will hedge a portion of their real dollar/pound exchange rate exposure by borrowing in pounds and lending in dollars. British and American investors thus will lend to and borrow from each other, and they will have opposite exposures to the dollar/pound exchange rate.

return. They are derived from the same basic notions: 1) investors will hold portfolios that are optimized given their specific needs, constraints and risk preferences; 2) in equilibrium, asset prices reflect these demands; and 3) assets with high expected returns are those that are correlated with any risk that a significant group of investors has been unable to eliminate from their portfolios.

Whether the basic CAPM or one of its multifactor extensions is the "correct" model of asset prices is ultimately an empirical question, one that is discussed in detail by Fama and French in their companion paper in this journal. Initial tests of the CAPM by Black, Jensen and Scholes (1972) and Fama and MacBeth (1973) supported the theory in that high beta stocks were found to have had higher returns than low beta stocks. However, the relationship between beta and average returns was not as steep as indicated by the theoretical Securities Market Line.

Since this early work, a vast body of research has looked for additional risk factors that affect expected returns. Most notably, Fama and French (1992) find that adding a "value" factor and a "size" factor (in addition to the overall market) greatly improves upon the explanatory power of the CAPM. The pervasiveness of these findings in follow-up research across time and other countries provides strong evidence that more than one systematic risk factor is at work in determining asset prices. However, the value and size factors are not explicitly about risk; at best, they are proxies for risk. For example, size per se cannot be a risk factor that affects expected returns, since small firms would then simply combine to form large firms. Another criticism of the Fama-French findings is that their value effect is based on giving equal weight to small and large companies and is much stronger than observed in capitalization-weighted value indexes. Until the risks that underlie the Fama-French factors are identified, the forecast power of their model will be in doubt and the applications will be limited.

Conclusion

The Capital Asset Pricing Model is a fundamental contribution to our understanding of the determinants of asset prices. The CAPM tells us that ownership of assets by diversified investors lowers their expected returns and raises their prices. Moreover, investors who hold undiversified portfolios are likely to be taking risks for which they are not being rewarded. As a result of the model, and despite its mixed empirical performance, we now think differently about the relationship between expected returns and risk; we think differently about how investors should allocate their investment portfolios; and we think differently about questions such as performance measurement and capital budgeting.

■ *I thank Josh Coval, Mihir Desai, Craig French, Ken Froot, Jim Hines, Elon Kohlberg, Adam Perold, Melissa Perold, Andrei Shleifer, Bill Sharpe, René Stulz, Timothy Taylor, Luis Viceira and Michael Waldman for helpful discussions and comments.*

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UNSG 2.37 Does Mr. Rigsby believe that an increase in investor risk aversion implies a corresponding increase in investor risk premiums for riskier securities? If the answer is no, please explain.

Response:

Yes.

Respondent: Bill Rigsby

Witness: Bill Rigsby

EXHIBIT
UNSG 35
ADMITTED

DATA REQUEST PACKET NO. 2

Staff's Responses to UNS Gas' Data Requests:

UNSG 2.28	UNSG 3.88
UNSG 2.36	UNSG 3.92
UNSG 2.43	UNSG 3.95
UNSG 2.44	UNSG 3.98
UNSG 3.78	UNSG 3.102
UNSG 3.83	UNSG 3.103
UNSG 3.84	UNSG 3.104
	UNSG 3.105

EXHIBIT
number UNSG 36
ADMITTED

UNSG 2.28 On page 14 of Mr. Parcell's Direct Testimony, he states "Rather, it more properly reflects an "availability of capital" since investors have been unwilling to invest in any assets other than U.S. Treasury Bonds." Please explain the term "availability of capital" as it is being used in this sentence.

RESPONSE: **The term "availability of capital" as used here, refers to the fact that during the past several months there has been a dramatic reduction in the stock market levels and a decline in capital available for lending by banks and other types of financial institutions. The lack of available capital is a primary reason for the actions of the Federal Reserve, U.S. Congress, and the U.S. Administration in formulating the extraordinary stimulus and financial policies over the past several months.**

RESPONDENT: **DAVID PARCELL**

WITNESS: **DAVID PARCELL**

UNSG 2.36 Regarding David C. Parcell's pre-filed Direct Testimony at page 38, what does Mr. Parcell believe the relationship to be between access to credit and the cost of common equity. Specifically:

a. Does Mr. Parcell believe there is a relationship between cost of common equity and access to credit? If the answer is no,, then please explain why not. If the answer is yes, then please explain what Mr. Parcell believes the relationship to be.

b. Does Mr. Parcell agree that access to credit was compromised during the time when, as he puts it, "the United States and global financial markets have been in turmoil"?

c. Does Mr. Parcell agree that entities both regulated and unregulated were seeking access to credit at a time when, as he puts it, "global credit markets [were] virtually coming to a standstill"?

d. Does Mr. Parcell agree that UNS Gas had the responsibility to ensure safe, reliable and adequate service regardless of the credit turmoil and to provide, as he puts it, "a product with no real substitutes"?

e. Does Mr. Parcell believe that Demand-Side Management programs for UNS Gas are non-productive since "consumers can do little to control the amount [of natural gas] they use"?

RESPONSE:

a. Mr. Parcell does believe there is a relationship between a company's risk/expected returns and access to credit. There could be some relationship between cost of capital and access to credit, but these are different concepts in the context of Mr. Parcell's testimony on this point.

b. Yes, in general. However, the access is likely less for regulated utilities.

c. Yes, in general. See also response to b.

d. He agrees with this.

e. Objection, this question mischaracterizes Mr. Parcell's testimony. Without waiving the objection, the following response is provided: No, this is not what Mr. Parcell is maintaining.

RESPONDENT: **DAVID PARCELL**

WITNESS: **DAVID PARCELL**

UNSG 2.43 Does Mr. Parcell agree that, according to his own FVROR analysis, a return on the Fair Value Increment of 2.5 percent is reasonable? If not, state why not.

RESPONSE: Yes, along with a 0 percent return being reasonable.

RESPONDENT: DAVID PARCELL

WITNESS: DAVID PARCELL

UNSG 2.44 Do investors expect real (i.e. non-inflation) growth in their investment? If not, explain why not.

RESPONSE: Mr. Parcell believes this to be the case.

RESPONDENT: DAVID PARCELL

WITNESS: DAVID PARCELL

UNSG 3.78 Please provide spreadsheets and workpapers that support Staff's analysis of UNS Gas' ability to earn the cost of equity recommended by Mr. Parcell. If no such supporting materials are available, please explain.

RESPONSE: Mr. Parcell does not address the future earnings of UNS Gas. His analyses address the cost of capital for the Company.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.83 On page 4, lines 3-5, of Mr. Parcell's Direct Testimony, he states that "...there is no justification for increasing UNS Gas' profit level as *(sic)* the same time that virtually all of its customers has *(sic)* suffering from lower incomes/profits."

a. Is it Mr. Parcell's position that no rate increase whatsoever should be granted to UNS Gas, regardless of the Company's cost of service?

b. Is it Mr. Parcell's position that some portion of the rate increase that UNS Gas would be entitled to under traditional cost-of-service ratemaking should be denied by the Commission in this case? Please explain.

c. If the answer to part (b) is yes, what percent or dollar amount of discount would satisfy Mr. Parcell's concerns, and how would such a discount be consistent with the Hope and Bluefield court cases cited in Mr. Parcell's Direct Testimony?

RESPONSE:

a. Objection, this data response mischaracterizes Mr. Parcell's testimony. Without waiving the objection, No.

b. Objection, this data response mischaracterizes Mr. Parcell's testimony. Without waiving the objection, No. Mr. Parcell is maintaining that UNS Gas' cost of equity for ratemaking purposes has not increased.

c. N/A

RESPONDENT: DAVID C. PARCELL; ROBIN MITCHELL

WITNESS: DAVID C. PARCELL

UNSG 3.84 On page 5, lines 9-10, of Mr. Parcell's Direct Testimony, he states that "Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base..." Does Mr. Parcell believe that the earned returns on equity recorded by UNS Gas in recent years represent fair returns on equity? Please explain in light of the authorized returns on equity granted in previous UNS Gas rate cases.

RESPONSE: Not necessarily. It should be noted that UNS Gas was subject to a rate freeze for several years after the purchase of Citizens' gas operations in Arizona.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.88 On page 13, lines 5-7, of Mr. Parcell's Direct Testimony, he makes reference to a 0.1% rate of inflation in 2008, and states that "This is indicative of virtually no inflation, which should also be reflective of lower capital costs."

a. By "capital costs" is Mr. Parcell referring to the cost of capital?

b. Does Mr. Parcell believe that the cost of capital is more influenced by (i) the current rate of inflation or (ii) the expected future rate of inflation? Please explain.

c. Does Mr. Parcell believe that the expected future rate of inflation, over a long investment horizon such as 20 years, is presently anywhere close to 0.1%? If the answer is no, what is Mr. Parcell's best estimate of long-term expected inflation?

RESPONSE:

a. Mr. Parcell is referring to both.

b. Both.

c. No. Mr. Parcell does not forecast long-term expected inflation.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.92 Regarding the discussion of investor expectations appearing on page 26, lines 9-17, of Mr. Parcell's Direct Testimony:

a. Does Mr. Parcell agree that two investors could have identical expectations of future dividends and earnings, yet reach different conclusions regarding valuation of a stock due to different perceptions of risk or different tolerances for bearing risk? If the answer is no, please explain.

b. Does Mr. Parcell agree that stock price declines can be produced by changing perceptions of risk or changes in investor risk aversion, even if future expectations of dividends and earnings have not changed? If the answer is no, please explain.

RESPONSE:

a. Yes, in part. Other factors could also play a role in the different conclusions.

b. Yes, but in the recent several months, it is widely believed that the financial crisis and recession are largely responsible for the declines in stock prices.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.95 Regarding the five points raised by Mr. Parcell in support of his assertion that the cost of capital has not increased for UNS Gas, which appear on pages 38-40 of his Direct Testimony:

As to the first point, please explain in detail how UNS Gas is "partially, if not largely, insulated from the impacts of depressed economic conditions."

a. Has Mr. Parcell examined the sales levels of UNS Gas since the "depressed financial conditions and financial crisis" arrived in late 2008? If so, please provide any analysis performed along with the conclusions reached.

b. If the "availability of capital" has been reduced, as discussed on page 14, lines 24-25 of his Direct Testimony, please explain how UNS Gas would be "insulated" from this problem.

c. As to the second point, please explain in detail how depressed profits in a recession cause a decreased in "capital costs."

   i. In this context, does Mr. Parcell equate "capital cost" with the "cost of capital"? Please explain.

d. As to the third point, is it Mr. Parcell's position that the Commission should ignore any increases to UNS Gas' cost of capital for purposes of setting rates in this proceeding, even if such increase is demonstrated and amply supported through evidence presented in this proceeding? Please explain.

e. As to the fourth point, does Mr. Parcell agree that an increase in the market price of risk (i.e., increase in investor risk aversion) can result in an increase in the cost of capital to a firm, even if that firm's risk profile has not changed? If the answer is no, please explain.

f. As to the fifth point, how would it be "counter-productive" to claim that UNS Gas should have a higher return at this time?

g. To whom would it be "counter-productive," and in what sense?

RESPONSE:

a. UNS Gas provides a service for which there are limited substitutes, at least in the short term. In addition, there are limited opportunities for substantially reducing the usage of natural gas. This is in contrast to the services or products sold by many unregulated firms.

b. He has not.

c. **Objection, this data request misstates Mr. Parcell's testimony. Mr. Parcell did not claim that UNS Gas is insulated from the "availability of capital" concept he cited in his testimony. On the other hand, Mr. Parcell observes that UNS Gas has raised new debt capital in recent months.**

d. **Decreased profits in a recession reflect a decline in the opportunity cost – the returns available from alternative investments.**

e. **Mr. Parcell believes that any actual costs, including capital costs, should be considered by the Commission for inclusion in rates.**

f. **Mr. Parcell believes such a situation is not the facts at this time.**

g. **It would be counter productive to use the existence of governmental efforts to reduce the cost of capital as an excuse to increase the cost of equity for a regulated utility.**

RESPONDENT: **DAVID C. PARCELL**

WITNESS: **DAVID C. PARCELL**

UNSG 3.98 Regarding the statement on page 40, lines 14-15, of Mr. Parcell's Direct Testimony, when does Mr. Parcell expect UNS Gas to earn his cost of capital recommendation? Please provide any supporting analyses.

RESPONSE: Objection, Staff is not required to provide such calculations. Such calculations are within the control of the Company. Mr. Parcell has not addressed UNS Gas' projected earnings.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.102 On page 45, lines 7-9, of his Direct Testimony, Mr. Parcell describes the calculation used to derive the FVROR for Chaparral City Water Company in Decision No. 70441.

a. Why did Mr. Parcell not recommend a similar calculation in this proceeding?

b. Does Mr. Parcell believe that the approach adopted by the Commission in Decision No. 70441 somehow result in unjust and unreasonable rates? If the answer is yes, please explain.

c. Is Mr. Parcell aware of the position taken by Staff on the calculation of FVROR in their Direct Testimony in Docket No. W-02113A-07-0551 involving Chaparral City Water Company? If yes, please explain why both of the approaches presented by Staff were rejected by Mr. Parcell in this UNS Gas rate proceeding.

RESPONSE:

a. Mr. Parcell believes that the FVROR calculation that he is recommending in the current proceeding, which is the same FVROR procedure he recommended in the Chaparral proceeding, is a viable procedure and has not been ruled out by the Commission as a viable procedure.

b. Mr. Parcell has not examined the reasonableness of the procedure cited, as it pertains to UNS Gas.

c. Yes. Mr. Parcell has not rejected any procedure. Rather, he is recommending the procedure he has previously advocated and that he continues to support.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

ARIZONA CORPORATION COMMISSION
DOCKET NO. G-04204A-08-0571
STAFF'S RESPONSE TO UNS GAS, INC.'S
THIRD SET OF DATA REQUESTS
July 7, 2009

UNSG 3.103 Did Mr. Parcell or any other Staff witness conduct any review or analysis to confirm whether UNS Gas' original cost rate base matches UNS Gas' capitalization, as suggested by Mr. Parcell on page 46, lines 10-15, of his Direct Testimony? If so, please provide the results of such review or analysis.

RESPONSE: Mr. Parcell uses the same capital structure proposed by the Company. Mr. Parcell does not address the level of original cost rate base.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.104 On page 47, lines 3-6, of his Direct Testimony, Mr. Parcell states that "...financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective."

a. By this statement, does Mr. Parcell mean that so long as the cost of capital is applied to original cost rate base, a utility such as UNS Gas will be automatically provided with an opportunity to earn a reasonable return on capital? Please explain.

b. How might an extended period of regulatory lag (i.e., the period between test year and the effective date of new rates), coupled with the use of an historical original cost rate base, affect a utility's opportunity to earn its cost of capital?

c. Does Mr. Parcell agree that a utility experiencing growth in its original cost rate base and is subject to significant regulatory lag will have a capitalization that exceeds its original cost rate base as last determined for ratemaking purposes? If the answer is no, please explain. If the answer is yes, please explain how the financial theory described on page 47 of his Direct Testimony serves to provide the utility with an opportunity to earn a reasonable return on its capital.

RESPONSE:

a. Mr. Parcell believes that the traditional regulatory process, which has been used for at least fifty years, is a tried and accepted procedure and has resulted in utility rates that satisfy the legal and financial criteria for a fair return. There are no guarantees of profits for utilities, or other types of enterprises.

b. This could have an impact, along with other factors.

c. It may, other things being the same.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

UNSG 3.105 Please confirm that the calculation shown in the table on page 48 of Mr. Parcell's Direct Testimony is mathematically equivalent to assigning a zero weighting to fair value rate base for purposes of setting rates. If the answer is no, please explain.

RESPONSE: Yes.

RESPONDENT: DAVID C. PARCELL

WITNESS: DAVID C. PARCELL

Summary of Arizona ROE Recommendations[1]
Mr. David Parcell

Utility	Parcell ROE Recommendation	Docket No.	Hearing Date	Decision No.	Decision Date
Arizona Water Company	10.00%	08-0440	August 31, 2009	N/A	N/A
Arizona Public Service Co.	11.00%	08-0172	August 19, 2009	N/A	N/A
UNS Gas	10.00%	08-0571	August 10-18, 2009	N/A	N/A
Arizona-American Water Co.	10.00%	08-0227	March 2009	N/A	N/A
Southwest Gas Corp.	10.00%	07-0504	June 2008	70665	Dec. 24, 2008
Tucson Electric Power Co.	10.25%	07-0402	July 2008	70628	Dec. 1, 2008
UNS Electric	10.00%	06-0783	Sept. – Oct., 2007	70360	May 27, 2008
UNS Gas	10.00%	06-0463	April 2007	70011	Nov. 27, 2007
Arizona Public Service Co.	10.25%	05-0816	Oct. – Dec. 2006	69663	June 28, 2007

EXHIBIT
Witness UNSG 37
ADMITTED

[1] Mr. Parcell also testified in two other cases in Arizona: (1) the Chaparral City "Remand" case (Docket No. 04-0616) regarding fair value issues; and (2) an AEPCO rate case in the early 1990s, but no ROE was stated.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-08-0172

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 19, 2008

EXHIBIT
UnS6 38
ADMITTED

setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100%, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for APS. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three Cost of Equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-11.0%
Capital Asset Pricing Model	8.8-9.1%
Comparable Earnings	9.5-10.5%

Q. What is your Cost of Equity recommendation for APS?

A. I recommend a cost of equity of 9.0 percent to 11.0 percent for APS. This reflects each of my three cost of equity model results. Within this range, I recommend an 11.0 percent level, or slightly above the return on equity approved for APS in the Company's last rate proceeding. Even though a lower cost of equity (e.g., the mid-point of my 9.0 percent to 11.0 percent range) could be justified, my 11.0 percent recommendation reflects Staff's

desire to aid APS in its efforts to attract captitol investment, as cited in the testimony of Staff witness Johnson.

Q. Please explain how the recent and current economic and financial crisis impacts the Cost of Equity for APS.

A. It is well chronicled that, over the past year and especially over the past few months, the United States and global financial markets have been in turmoil. The impacts of this have been far-reaching and extreme, with global credit markets virtually coming to a standstill. This crisis and its impact, however, do not imply that the cost of equity for electric utilities such as APS has increased. I say this for the following reasons.

First, it must be emphasized that depressed economic conditions and the financial crisis affects virtually all sectors of the economy – households, small businesses, larger commercial and industrials – and, in most cases, the impact is greater than is the case for APS. APS is a regulated utility that sells a product that has no real substitutes and is a product that consumers can do little to control the amount they use. As such, APS and utilities are partially, if not largely, insulated from the impacts of depressed economic conditions.

Second, if a recession is a significant one, the major impact will be to depress the profits of most enterprises. As a result, it is to be expected that capital costs will decrease if a significant recession occurs. There is no justification for increasing the profit level of a regulated utility such as APS at the same time that other enterprises are experiencing lower profits.

Third, even if APS were to incur higher costs of debt and/or other capital costs, these costs can be passed along to ratepayers at the next rate proceeding. Unregulated firms cannot do this.

Fourth, there is no indication that APS' risks have increased since its last rate proceeding. The Company's debt ratings have remained the same, indicating an objective assessment by the rating agencies that there is no significant change in APS' credit quality. Absent a demonstration that APS' risks have increased, there is no justification for increasing its cost of equity.

Fifth, the United States and global governments have and are taking extraordinary measures to avoid a further worsening of the current market turmoil. Most of these measures are designed to put liquidity into the credit markets and make credit more accessible again and, in the process, restore more confidence to the financial markets. All of these measures are clearly designed to lower the cost of capital. In this environment, it would be counter-productive to make any claim that APS should have a higher return at this time due to the above-cited market turmoil.

XII. TOTAL COST OF CAPITAL

Q. What is the total Cost of Capital for APS?

A. Schedule 1 reflects the total cost of capital for the Company using APS's proposed capital structure and cost of debt along with the range of common equity costs my analyses support. The resulting total cost of capital is a range of 7.51 percent to 8.58 percent. I recommend that a 8.58 percent total cost of capital be established for APS.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUSCON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

FEBRUARY 29, 2008

EXHIBIT
UNSS 39
ADMITTED

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	9.5-9.8%
Comparable Earnings	10.0-10.5%

My overall conclusion from these results is a reasonable range of 9.5 percent to 10.5 percent, which focuses on the respective individual model findings.

The mid-point of this range is 10.0 percent, which is applicable to the proxy companies. However, this 10.0 percent mid-point is not applicable to TEP, which has higher risk and thus a lower cost of capital than the proxy group companies. This higher risk is due to the following:

- Lower bond ratings of TEP versus the bond ratings of the proxy companies; and,
- Lower equity ratio, and thus higher financial risk, for TEP versus the proxy companies.

I recommend a cost of equity at the upper end of this range, or 10.25 percent for TEP, to recognize these differences.

UNS Gas / Rates 4/24/2007

G-04204A-06-0463, etc. Vol. VI

Page 905 to Page 1083

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EXHIBIT
Unsg 40
ADMITTED

1 2003 by S&P.
2 Q. Thank you.
3 And are you the same David Parcell that testified
4 in the recent APS rate case?
5 A. Indeed I am.
6 MR. SABO: And, Your Honor, could I have a moment
7 for an exhibit?
8 ACALJ NODES: Sure.
9 MR. SABO: Your Honor, we have handed out a page
10 that has been marked as UNSG-34, and that is a one-page
11 excerpt from the transcript of the APS case.
12 Q. BY MR. SABO: Mr. Parcell, I'm going to read you
13 a question that was asked by somebody in that case -- it
14 might have been Mr. Grant -- and then read you your
15 answer. And then I'm going to ask if you would still
16 agree with that answer today.
17 A. Sure.
18 Q. And the question is: "Mr. Parcell, explain to me
19 why you pick a comparison group?"
20 And then the answer after a short discussion of
21 the lunch hour was, "You want a grouping that has similar
22 risk and therefore a similar expected cost of capital to
23 the subject company."
24 Would you still agree with that today?
25 A. Yes.

DATA REQUEST PACKET

RUCO's Responses to UNS Gas' Data Requests:

UNSG 2.25
UNSG 2.48
UNSG 2.55
UNSG 3.2
UNSG 3.13
UNSG 3.16
UNSG 3.18
UNSG 3.20
UNSG 3.21
UNSG 3.22
UNSG 3.31
UNSG 3.34
UNSG 3.35
UNSG 3.36

EXHIBIT
UNSG 41
ADMITTED

UNSG 2.25 Regarding Calculation 3 appearing on page 2 of Schedule D attached to Mr. Smith's Direct Testimony:

a. Does Mr. Smith agree that the methodology used in Calculation 3 is mathematically equivalent to a zero weighting of FVRB in the determination of revenue requirement? If the answer is no, please explain.

b. Please verify that the only difference between (i) the $803,000 overall revenue requirement determined on an original cost basis on page 1 of Schedule A attached to Mr. Smith's Direct Testimony and (ii) the $800,000 overall revenue requirement determined using Calculation 3 on page 2 of Schedule A attached to Mr. Smith's Direct Testimony, is due to the rounding of decimal places in the calculation of such amounts. If RUCO cannot verify this, please explain why.

c. Please explain why the revenue requirement for Calculation 3 was evaluated as being "too low" on page 2 of Schedule A attached to Mr. Smith's Direct Testimony. Please provide all analyses supporting this conclusion.

Response:

a. Mr. Smith agrees that the methodology used in Calculation 3 could be viewed as mathematically equivalent to a zero weighting of FVRB in the determination of revenue requirement and believes this method is nevertheless appropriate for Commission consideration based on the underlying support 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

UNS 2.25 (Continued)

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, Docket No. W-02113A-04-0616.

b. 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 and Mr. Smith believes this method is nevertheless appropriate for Commission consideration based on the underlying support by appropriate economic, financial and ratemaking principles, as described in the response to part a.

c. Based on the application of informed judgment, the result of Calculation 3 would have produced a rate increase that was slightly below the OCRB-revenue requirement, 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. The four FVROR methods on 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.

UNS 2.25 (Continued)

Respondent: Ralph C. Smith

Witness: Ralph C. Smith

UNSG 2.48 Does Mr. Smith believe that UNS Gas will actually be able to earn the 8.61% authorized return on equity proposed by RUCO? Please explain and provide any supporting analyses for this conclusion.

Response:

Mr. Smith has applied the rate of return on OCRB recommended by RUCO Witness Rigsby. Whether UNSG will earn a rate of return that is authorized by a regulatory commission is dependent upon numerous factors including management decisions occurring after the test year and the impact of items that are not considered for ratemaking purposes.

Respondent: Ralph C. Smith

Witness: Ralph C. Smith

UNSG 2.55 In the UNS Gas case filed July 13, 2006, RUCO Witness Ms. Diaz-Cortez presented a Schedule MDC-1, which she said demonstrated that UNS Gas customers do not exhibit the level of extreme seasonality that would justify a departure from the traditional residential annualization approach. This exhibit was referenced in Decision No. 70011. Were Ms. Diaz-Cortez's conclusions - which were in part the basis for the Commission's acceptance of the traditional approach and rejection of UNS Gas' approach - incorrect or faulty? Why or why not?

Response:

Mr. Smith is unsure what the RUCO Witness in the prior case meant by extreme seasonality. He is aware that in the prior UNSG rate case both RUCO (Witness Diaz Cortez) and Staff (Witness Ralph Smith) used an annualization calculation that was based on December, which was referred to as the "traditional approach". In the current case, Mr. Smith has reversed UNSG's proposed annualization which was based on June results for the reasons explained in his testimony, including that UNSG proposed to decrease test year revenue when customer growth has been occurring year-over-year including the test year. Year-over-year customer growth should generally equate to increased base rate revenues, other things being equal. Mr. Smith is reviewing the Staff calculation of annualized revenue in the current UNSG rate case, which uses December as the basis for the annualization, similar to the "traditional" annualization calculation that was accepted in Docket No. G-04204A-06-0463 as a potential alternative to using test year as-recorded revenue in order to appropriately account for customer growth in the test year.

Respondent: Ralph Smith

Witness: Ralph C. Smith

UNSG 3.2 Arizona Administrative Code R14-2-103.A.3.l defines "prudently invested" as "Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made." Under this standard, does RUCO believe that the projects included within UNS Gas' requested Post Test Year Non-Revenue Producing Plant are prudently invested? If the answer is no, please specify each project that is not prudently invested and explain why.

RESPONSE:

RUCO has not conducted a prudence evaluation of UNSG's post test year plant in the current UNSG rate case and thus cannot opinion as to whether UNSG's request would pass muster under a prudence investigation. RUCO is not aware of any facts in the current UNSG rate case that would demonstrate that the post test year plant was imprudent, and RUCO witness Smith has recommended the removal of UNSG's request for post test year plant not on grounds that it was imprudent but rather for the reasons described in his testimony. For a number of reasons, including the following, RUCO does not support UNS Gas' request for rate base inclusion of CWIP/post test year plant in the current case:

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

UNSG 3.2 (Continued)

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

3) The Company has not demonstrated that its June 30, 2008 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for mains and services and transportation equipment 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 continued customer growth that it supports, would be imbalanced. Similarly, expenses have not been reduced for reduced maintenance that could result after the test year from the new or replacement plant that was placed into service after the end of the test year; consequently, it would be imbalanced to include the plant but no expense reductions.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.13 Please refer to the Direct Testimony of Ralph C. Smith, page 25, line 25, where Mr. Smith argues against "rote application" of the customer annualization method approved by the Commission in UNS Gas' last rate case. Does Mr. Smith also agree that there should not be "rote application" of the Commission's previous determinations in that case concerning post test year plant, customer advances, and incentive compensation?

RESPONSE:

Yes, Mr. Smith recommends that the facts and circumstances in each case be reviewed and considered. His testimony on the customer annualization highlighted that the Company's calculation produced a decrease in test year revenue when UNSG had been experiencing a trend of year-over-year customer growth continuing through the test year, thus the reduction to test year revenue was unreasonable. The facts in the current rate case, and the result of the calculation differ from the prior UNSG rate case. Mr. Smith believes that the facts of the current UNSG rate case concerning post test year plant, customer advances and incentive compensation warrant adjustments that are similar in concept to the Commission's findings in the prior UNSG rate case for the reasons explained in his testimony.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.16 Assume that the prudent total compensation for utility employee X is $50,000, exclusive of health insurance.

a. What incentives are created by paying the full $50,000 as straight salary?

b. What incentives are created by paying $10,000 as a potential bonus for meeting customer service goals, and $40,000 as straight salary?

c. What incentives are created by paying $10,000 as a potential bonus for meeting customer service goals, $5,000 as a stock-based compensation and $35,000 as straight salary?

d. Which compensation structure (a, b or c) is most beneficial to ratepayers? Why?

e. Under Mr. Smith's proposals in this case, under compensation structure a, what amount of expense would be reflected in revenue requirement?

f. Under Mr. Smith's proposals in this case, under compensation structure b, what amount of expense would be reflected in revenue requirement?

g. Under Mr. Smith's proposals in this case, under compensation structure c, what amount of expense would be reflected in revenue requirement?

h. Which compensation structure allowed the utility the greatest amount of expense reflected in revenue requirement? Is that compensation structure the same as the structure identified in response to sub-part d? If not, why is that an optimal result as a matter of regulatory policy?

i. Does RUCO believe that the total compensation to UNS Gas employees in the test year was unreasonable? If so, please provide the basis for that belief and all supporting materials.

UNSG 3.16 (Continued)

RESPONSE: a. This would depend on the way an individual employee viewed his/her job. Presumably the incentives of any pay structure include showing up for work on time and performing competently and diligently in fulfilling the job requirements.

b. The request is phrased in a manner to presume that the bonus might incent the affected employee to work harder to meet the customer service goal.

c. The request is phrased in a manner to presume that the bonus might incent the affected employee to work harder to meet the customer service goal, and to make management decisions to try to keep the earnings up and the stock price high, to the extent that such actions would produce more value for the employee in the form of the stock based compensation component.

d. If Mr. Smith's recommendations were adopted, the "c" hypothetical.

e. Assuming the entire amount was charged to expense and none was capitalized or charged to non-expense accounts or to non-utility activities or other affiliates, $50,000, unless any was for SERP, in which case the SERP expense would be removed.

f. Assuming the entire amount was charged to expense and none was capitalized or charged to non-expense accounts or to non-utility activities or other affiliates, $45,000, unless any was for SERP, in which case the SERP expense would be removed. The $45,000 is based on removing one-half of the

UNSG 3.16 (Continued)

incentive compensation expense to reflect the 50/50 sharing that the Commission has adopted in several recent rate case decisions.

g. Assuming the entire amount was charged to expense and none was capitalized or charged to non-expense accounts or to non-utility activities or other affiliates, $40,000, unless any was for SERP, in which case the SERP expense would be removed. The $40,000 is based on removing one-half of the incentive compensation expense to reflect the 50/50 sharing that the Commission has adopted in several recent rate case decisions, and removing the expense for the stock based compensation.

h. The "a" hypothetical. No. The "c" hypothetical appears to represent an optimal result as a matter of regulatory policy as such policy has been articulated by the Commission in a series of its rate case decisions concerning various elements of utility compensation. As articulated in such decisions, the Commission has rejected attempts by utilities to focus only on the amounts of total compensation and whether the total was reasonable or not, and the Commission has in a series of decisions evaluated the specific components of utility compensation, including utility management and executive compensation, specifically for ratemaking purposes. As an illustrative example, the Commission noted in a prior APS case, stock-based 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.) Several other illustrative examples of how

the Commission has evaluated and decided similar issues were cited in Mr. Smith's direct testimony.

i. Confidential UniSource executive compensation studies that Mr. Smith reviewed in a previous rate case raised questions about the reasonableness of some of the UniSource compensation and information presented by Southwest Gas in its last rate case suggested that UNS was less efficient on a per-customer cost basis. Establishing executive compensation at a 75th percentile level, for example, could be one indication of above-average compensation that could be viewed as unreasonable for ratemaking purposes. Public information suggests that there may be UNS executives who are earning above-average compensation which might be considered unreasonable for ratemaking purposes. Additionally, a series of prior Commission decisions have found that it is inappropriate for jurisdictional ratemaking purposes to charge ratepayers for certain specific elements of utility compensation, and Mr. Smith has attempted to make his recommendations consistent with the analysis and reasoning of those decisions. Thus, based on the series of prior Commission decisions cited in Mr. Smith's direct testimony, portions of the UNS compensation are disallowable, in the sense that the same or similar compensation components have been disallowed by the Commission in prior decisions.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.18 Does Mr. Smith contend that UNS Gas' incentive compensation costs are imprudent? If yes, please explain, including comparisons to incentive compensation costs of other regulated gas utilities.

RESPONSE:

Mr. Smith contends that portions of UNS Gas' compensation are disallowable for ratemaking purposes. A prudence evaluation was not necessary in order to implement the ratemaking policies and evaluation articulated by the Commission in a series of recent decisions on utility incentive compensation costs, consequently, one was not undertaken on behalf of RUCO in the current UNSG rate case. Mr. Smith's testimony explains how incentive compensation costs were treated for ratemaking purposes in the last UNSG rate case as well as for Southwest Gas Corporation, another regulated gas utility with significant operations in Arizona. A series of prior Commission decisions have found that it is inappropriate for jurisdictional ratemaking purposes to charge ratepayers for certain specific elements of utility compensation, and Mr. Smith has attempted to make his recommendations consistent with the analysis and reasoning of those decisions. Thus, based on the series of prior Commission decisions cited in Mr. Smith's direct testimony, portions of the UNS compensation are disallowable, in the sense that the same or similar compensation components have been disallowed by the Commission in prior decisions.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.20 Does Mr. Smith believe that it is common for an investor-owned gas utility to have an incentive compensation program? If no, please explain and provide examples of comparable gas utilities without such programs.

RESPONSE:

Mr. Smith has not undertaken to determine which do and do not specifically have such programs, since that type of research that did not appear to be necessary to apply the analytical framework suggested in the series of recent Commission orders on this issue cited in Mr. Smith's testimony in the context of the current UNSG rate case; however, he is generally aware that some investor owned gas utilities, including UNSG and Southwest Gas, have such programs and generally believes it is not uncommon among larger investor owned gas utilities.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.21 Does Mr. Smith believe that it is common for an investor-owned gas utility to have some stock-based compensation expenses? If no, please explain and provide examples of comparable gas utilities without such programs.

RESPONSE:

Mr. Smith has not undertaken to determine which do and do not specifically have such programs, since that type of research that did not appear to be necessary to apply the analytical framework suggested in the series of recent Commission orders on this issue cited in Mr. Smith's testimony in the context of the current UNSG rate case; however, he is generally aware that some investor owned gas utilities, including UNSG and Southwest Gas, have such programs and generally believes it is not uncommon among larger investor owned gas utilities.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.22 Does Mr. Smith believe that it is common for an investor-owned gas utility to have a SERP program? If no, please explain and provide examples of comparable gas utilities without such programs.

RESPONSE:

Mr. Smith has not undertaken to determine which do and do not specifically have such programs, since that type of research that did not appear to be necessary to apply the analytical framework suggested in the series of recent Commission orders on this issue cited in Mr. Smith's testimony in the context of the current UNSG rate case; however, he is generally aware that some investor owned gas utilities, including UNSG and Southwest Gas, have such programs and generally believes it is not uncommon among larger investor owned gas utilities.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.31 Please provide a detailed budget from Mr. Smith showing how UNS Gas could prepare and prosecute this case using his $300,000 recommended allowance for rate case expense.

RESPONSE:

Mr. Smith has not prepared such a budget and notes that the recommended allowance for UNSG in the current case is consistent with the allowances for rate case cost that was allowed by the Commission in the last UNSG rate case, as well as in the last UNS Electric rate case.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.34 Does RUCO dispute that UNS Gas experienced an average fuel price of $3.35/gallon during the test year?

RESPONSE:

No, however that period included some very high prices and thus indicated a normalization to reflect current prices was warranted as shown in RUCO's adjustment.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.35 Does RUCO believe that the future fuel costs are "known and measurable?" If so, please provide all support for that belief.

RESPONSE:

Not in the same sense that some other costs are; specifically, gasoline prices have been quite volatile and difficult to predict, thus a ratemaking allowance based on recent known prices over some representative average period should be considered.

RESPONDENT: Ralph C. Smith

WITNESS: Ralph C. Smith

UNSG 3.36 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." Does RUCO agree with this statement?

RESPONSE:

RUCO generally agrees with the statement but is 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.

RESPONDENT: RUCO Counsel and Ralph C. Smith

WITNESS: Ralph C. Smith

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 20, 2009

RUCO 1.88 Refer to Dallas Dukes testimony page 11, lines 7-8. Provide for each project: 1) a description of the project, 2) the projected in service date, 3) and all costs expended to date.

RESPONSE: UNS Gas is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE: Please see the Excel workbook RUCO 1.88 on the enclosed CD. The Excel file is not identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Dallas Dukes

EXHIBIT
UNSG 42
ADMITTED

Uns Gl Project/Task #	Uns Gl Project/Description	Balance	Non Revenue Producing	Cost to Date (5/6/09)	Date in Service or Est Date	Comments
250000A	**UNSG Transportation Equip**	**-13,553.47**	**-13,553.47**			
DR10000	Vehicle Retirement					
250910A	**Office Furn & Eq - New (Admin)**	**649.37**	**649.37**			
DA10046	Security System for Shamrell Office			9,899.58	10/24/07	
250912A	**CompEquip - UNSG**	**3,726.80**	**3,726.80**			
DA10011	IT Equipment Purchases - UNSG Flagstaff			30,170.44	04/01/08	
250912B	**Comp Equip- Rep (Admin)**	**-2,687.40**	**-2,687.40**			
DA10052	Upgrade To Shamrell Conference Room			16,950.23	03/23/08	
250913A	**Computer Software - New (Admin**	**-252.30**	**-252.30**			
DA10060	1213 Installations GasDay Svc Tech			32,196.00	09/02/08	
250915A	**ESRI Upgrade**	**2,168.51**	**2,168.51**			
250940A	**Tools,Shop,Gar Eq - New(Admin)**	**3,021.49**	**3,021.49**			
DA10042	Repair Equipment, Tapping & Plugging Equipment			126,467.48	11/01/07	
DA10045	High Pressure Nordstrom 400-D Grease Gun			845.76	07/18/07	
DA10056	Hydraulic Squeezer Tools for Training Dept			9,176.20	04/01/08	
250950A	**Laboratory Equip - New (Admin)**	**185,730.21**	**185,730.21**			
DA10057	Sensit Gold Combustible Gas Indicators & Trak-it III Combustible Gas Indicators			186,109.24	05/30/08	
250960A	**Power Operated Eq - New(Admin)**	**408.80**	**408.80**			Late Adjustment
251200B	**Mains-Repl-Flagstaff**	**24,516.26**	**24,516.26**			
DF00082	Service Replacement Flagstaff - Various Locations			88,413.70		
251500B	**Mains - CIP - Flagstaff**	**66,981.18**	**66,981.18**			NOT LISTED ON ORIGINAL NON-REVENUE LIST
DF10418	Huntington Drive CIP			51,689.77	03/25/08	
DF10424	4" PE main 7170 Yancey Lane			74,251.20	06/02/08	
251900A	**Structures & Improv-New (Flag)**	**26,021.40**	**26,021.40**			
DF10410	Butler Facility Improvements 2008			433,535.68	10/06/08	
251922A	**Trans Eq < 1 Ton - New (Flag)**	**44,153.98**	**44,153.98**			
DF10417	Two 2008 Ford 4x4 Rangers Units # 10278 & 10279			42,403.25	06/11/08	
251922B	**Trans Eq < 1 Ton - Rep (Flag)**	**42,615.32**	**42,615.32**			
DF10416	2 7X14 Enclosed Trailers Units #90135 &90136			22,376.05	05/20/08	
251923A	**Trans Eq > 1 Ton - New (Flag)**	**3,782.09**	**3,782.09**			Late Adjustment
251940A	**Tools,Shop,Gar Eq - New (Flag)**	**-23.73**	**-23.73**			Late Adjustment
251950B	**Laboratory Equip - Rep (Flag)**	**58.09**	**58.09**			Late Adjustment
251970A	**Comm Equip - New (Flag)**	**6,598.36**	**6,598.36**			
DF10423	Radios			6,214.56	07/30/08	
252200A	**Services - Rep - King**	**20,661.89**	**20,661.89**			
DH00087	Service Replacements for Lake Havasu			139,196.00	08/05/08	
252376B	**Mains Volun Repl - King**	**401.87**	**401.87**			
DH10058	Replace Pipe on Londaon Bridge Rd No. 2			12,351.55	04/23/07	
DH10135	Repl PVC on Catherine			19,097.00	07/22/08	
252501B	**CIP - Lake Havasu**	**-10,400.78**	**-10,400.78**			NOT LISTED ON ORIGINAL NON-REVENUE LIST
DH10070	Lower Indain Peak Wash			2,180.51	02/22/07	
DH10097	Havasupai Wash			11,987.23	01/19/08	
DH10099	Kiowa Drain			23,636.30	06/21/08	
DH10100	San Juan Drain			1,352.43	09/27/07	
DH10105	Repl PVC on San Juan Dr			31,593.49	02/23/08	
DH10116	Repl on Hurricane Dr			66,534.20	04/03/08	
DH10117	Repl PVC on Barranca Dr			15,786.70	12/22/08	
DH10119	Repl PVC on Huntington Drive			19,625.34	05/07/08	
DH10129	Replace 2" PVC Main on Nautilus Dr			6,809.33	04/23/08	
DH10132	Repl PVC on Aloha Dr			17,242.11	07/18/08	
252900A	**Structures & Improv-New (King)**	**6,531.06**	**6,531.06**			
DK10340	Add New Wall w/3' doors & Planter box			6,661.76	04/30/08	
252922A	**Trans Eq < 1 Ton - New (King)**	**20,657.57**	**20,657.57**			
DK10325	2008 Ford 1/2 ton 4x2 Unit # 10276			20,157.96	05/05/08	
252923A	**Trans Eq > 1 Ton - New (King)**	**-0.01**	**-0.01**			Late Adjustment
252940A	**Tools,Shop,Gar Eq - New (King)**	**4,800.51**	**4,800.51**			
DH10094	Air Hammer for C&M Crew			525.78	05/25/07	
DH10122	Compaction Wheel			4,198.32	04/01/08	
DH10123	LH Coppus Portable Ventilator			464.42	02/14/08	
252950A	**Laboratory Equip - New (King)**	**195.00**	**195.00**			Late Adjustment
252960B	**Power Operated Eq - Rep (King)**	**69,227.87**	**69,227.87**			
DK10181	2006 Case Backhoe Unit # 00100			64,296.47	03/01/07	
DK10328	2008 Yale Forklift Model GLP06VX Unit # 00160			34,311.50	05/28/08	
252970A	**Comm Equip - New (King)**	**97.65**	**97.65**			Late Adjustment
253200B	**Mains-Repl-Prescott**	**-1,327.84**	**-1,327.84**			Late Adjustment
253203B	**Mains - Rep - Pres**	**-10,683.18**	**-10,683.18**			Late Adjustment
253376B	**Mains Volun Repl - Pres**	**62,083.28**	**62,083.28**			

Uns Gl Project/Task #	Uns Gl Project/Description	Balance	Non Revenue Producing	Cost to Date (5/6/09)	Date in Service or Est Date	Comments
DP10477	Orchard Ranch Encroachment			1,374.82	01/04/08	
DP10555	YMHE CV PVE Repl Supai			130,120.85	07/16/08	
253380B	**Services Repl - CIP - Prescott**	**0.54**	**0.54**			Late Adjustment
253380C	**Services Repl - CIP - PV**	**88,766.47**	**88,766.47**			
DP00088	Service Repl-CIP-Prescott			645,015.75	09/10/08	
DP00099	Service Repl-CIP-Prescott Valley			37,377.80	09/10/08	
253400S	**Mains-System Improv-Pres**	**265.21**	**265.21**			Late Adjustment
253500B	**Mains - CIP - Prescott**	**849,621.38**	**849,621.38**			NOT LISTED ON ORIGINAL NON-REVENUE LIST
DP10410	Copper Basin CIP Ph 2			750,827.84	12/15/08	
DP10420	Install & Remove mains outside new Hwy widenin Pavement Structure			708,708.90	09/10/08	
DP10489	Downer Trail CIP			94,681.03	03/03/08	
253501B	**Mains - CIP - Prescott Valley**	**-0.07**	**-0.07**			Late Adjustment
253910A	**Office Furn & Eq - New (Pres)**	**15,217.77**	**15,217.77**			
DP10460	5 Drawer Flat File			1,386.85	06/21/07	
DP10590	Map Drawer Cover			649.21	09/12/08	
DP10618	Office Name Plates			3,659.86	1212/08	
253922A	**Trans Eq < 1 Ton - New (Pres)**	**-13,609.79**	**-13,609.79**			Late Adjustment
253923A	**Trans Eq > 1 Ton - New (Pres)**	**760.00**	**760.00**			late adjustment
253940A	**Tools,Shop,Gar Eq - New (Pres)**	**1,998.13**	**1,998.13**			
DP10485	Tensile & Guide Bend Machine, Hydraulic Pump, Plug & Die Set			8,231.66	08/28/07	
DP10533	4" IPS Range Squeeze Tool			760.14	02/01/08	
253940B	**Tools, Shops & Gar Equip Repl Pres**	**-7.86**	**-7.86**			late adjustment
253950A	**Laboratory Equip - New (Pres)**	**-6.74**	**-6.74**			late adjustment
253960A	**Power Operated Eq - New (Pres)**	**122.75**	**122.75**			late adjustment
255200B	**Mains-Repl-Verde Valley**	**545.23**	**545.23**			late adjustment
255500B	**Mains - CIP - Verde**	**5,950.49**	**5,950.49**			NOT LISTED ON ORIGINAL NON-REVENUE LIST
DV10145	Morgan to the Y in Sedona			1,407,586.93	10/30/09	90% COMPLETE WAITING FOR ADOT ROW TO COMPLETE
255910A	**Office Furn & Eq - New (Verde)**	**2,174.27**	**2,174.27**			
DV10152	Advantage Shredder			1,288.00	02/29/08	
DV10165	5 Drawer Cabinet			897.49	02/14/08	
255912A	**Comp Equip - New (Verde)**	**7,626.60**	**7,626.60**			
DV10043	IT Equipment purchases - UNSG Verde Valley			22,708.69	03/15/07	
255922A	**Trans Eq < 1 Ton - New (Verde)**	**7.06**	**7.06**			late adjustment
255923B	**Trans Eq > 1 Ton - Rep (Verde)**	**2,817.25**	**2,817.25**			
255940A	**Tools,Shop,Gar Eq - New(Verde)**	**-276.68**	**-276.68**			late adjustment
255940B	**Tools, Shops & Gar Equip Repl Verde**	**-520.26**	**-520.26**			late adjustment
255950A	**Laboratory Equip - New (Verde)**	**-20.16**	**-20.16**			late adjustment
255970A	**Comm Equip - New (Verde)**	**5,802.40**	**5,802.40**			
DV10169	*Kenwood portable radio*			5,182.50	06/02/08	
256200A	**Services - Rep - Nog**	**162,003.88**	**162,003.88**			
DS10110	Repl Serviceline Martinez Subdivision			275,587.05	12/11/07	
256376B	**Mains Volun Repl - Nog**	**455,785.02**	**455,785.02**			
DS10074	Coronado Subdivision			415,824.14	11/16/07	
256922A	**Trans Eq < 1 Ton - New (Nog)**	**5,292.22**	**5,292.22**			
DS10012	CC591 Nogales Gas to purchase TEP Unit #5181, new unit #80034			9,473.24	04/02/08	
256922B	**Trans Eq < 1 Ton - Rep (Nog)**	**0.01**	**0.01**			late adjustment
257200B	**Mains-Repl-SL**	**660.08**	**660.08**			
DL10106	Hwy 87 Winslow			16,879.35	08/01/07	
257400S	**Mains-System Improv-Show Low**	**284,881.03**	**284,881.03**			
DL10162	E Adams 6in Stl Reinforcement			162,332.16	06/05/08	
DL10187	N 1st Av & W Adair Dr			37,304.44	07/09/07	
DL10202	4" PE N 24th Dr to N 16th Ave			164,411.28	05/29/08	
DL10215	Holbrook Reinforcement			81,512.80	01/22/08	
DL10234	Snowflake Taylor Loop			42,543.50	03/06/08	
257900A	**Structures & Improv-New SL**	**6,919.91**	**6,919.91**			
DL10119	Show Low Office Carpet			6,919.91	12/03/07	
257940A	**Tools,Shop,Gar Eq - New SL**	**242.62**	**242.62**			
DL10219	Hyd Shore			10,574.27	02/04/08	
DL10225	Metrotech 810 Line Tracer			2,558.73	03/01/08	
DL10228	Machine, Drilling T-101b			14,293.99	02/26/08	
257940B	**Tools,Shop,Gar Eq - Rep SL**	**196.84**	**196.84**			
DL10188	Air Drill			1,260.65	08/11/07	
257950A	**Laboratory Equip - New- SL**	**217.64**	**217.64**			
DL10241	Holiday Detector			3,578.00	04/22/08	
257970A	**Comm Equip- New SL**	**212.52**	**212.52**			late adjustment
		2,439,805.61	2,439,805.61	6,694,219.37		

Capital Project Actual vs. Budget (Curr.Mth.)
UNS GAS
Capital
UNS UniSource Energy
289 Contr in Aid of Construc
032.T UNS Gas, Inc..Total Bus Ctr

	7-Dec	8-Jan	8-Feb	8-Mar	8-Apr	8-May	8-Jun	
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Total
C090605 UEG Services - Blanket	(44,483)	(61,454)	(70,293)	(66,136)	(94,396)	(39,749)	(92,595)	(469,106)
251380A Services - Bl - Flag	(20,197)	(12,251)	(8,879)	(10,077)	(22,971)	(10,257)	(15,141)	(99,773)
252380A Services - Bl - King	(5,607)	(16,454)	(19,151)	(10,768)	(16,112)	(9,974)	(19,043)	(97,109)
253380A Services - Bl - Pres	(8,207)	(12,073)	(20,000)	(28,788)	(13,933)	(9,970)	(30,397)	(123,369)
255380A Services - Bl - Verde	(152)	(1,575)	(1,610)	(2,548)	(3,038)	(1,936)	(3,805)	(14,664)
256380A Services - Bl - Nog	(2,881)	(6,440)	(400)	(1,135)	(1,152)		(3,037)	(15,045)
257380A Services - Bl - SL	(7,439)	(12,660)	(20,253)	(12,820)	(37,190)	(7,612)	(21,172)	(119,146)

Cost of Capital				Tax Gross-up	
Debt	50.01%	6.49%	3.25%	1.0000	3.25%
Equity	49.99%	11.00%	5.50%	1.6366	9.00%
	100.00%		8.75%		12.25%

Contributions for Feet of Service	$	(469,106)
After Tax Requested Return		12.25%
Increase Avoided	$	(57,472)

EXHIBIT
UNSG 43
ADMITTED

CARES Customer Analysis

Census data shows that around 27% of households in our service territory have household incomes less than or equal to 150% of the Federal poverty levels, and another 12% of households have incomes between 150% and 200% of poverty

Our CARES program has around 8,000 subscribers out of around 132,000 residential customers (May 2009).

Applying poverty percentages to our customer base, the customer estimates are:

Poverty Level	Customers	Share
150% or less	35,640	27%
150%-200%	15,840	12%
over 200%	80,520	61%
Total	132,000	100%

Applying a 22.4% low income program participation rate (actual current participation rate), the estimated subscription is:

Poverty Level	Participating Customers
150% or less	8,000
150%-200%	3,556

Rate impact on non-CARES customers of current CARES program and participation rate is approximately $4.00 per customer annually.

Rate impact on non-CARES customers if CARES program is expanded to 200% FPL and participation rate remains constant is approximately an additional $2.00 for an overall impact of $6.00 per customer annually.

EXHIBIT
UNSG 44
ADMITTED

UNS Gas Advertising - Actuals 2008

	Actual $	% of Actual Total
Gas Safety	297,867	72.84%
Low-Income / Winter Gas Prices	98,347	24.05%
Community Advertising / Marketing	12,368	3.02%
Promotional Items	372	0.09%
Total	**408,954**	100.00%

Low-Income Advertising

Bill Inserts	28,000	6.85%
Brochures	3,890	0.95%
Newspaper	8,747	2.14%
Radio	5,708	1.40%
Total Low-Income Advertising	**46,345**	**11.33%**

UNS Gas Advertising Budget 2009

	Budget $	% of Total Ad Budget
Gas Safety	265,800	55.44%
Low-Income / Winter Gas Prices	172,000	35.88%
Community Advertising / Marketing	40,000	8.34%
Promotional Items	1,600	0.33%
Total	**479,400**	**100.00%**

Low-Income Advertising

Bill Inserts	32,000	6.68%
Brochures	5,000	1.04%
Newspaper	9,000	1.88%
Radio	6,000	1.25%
Total Low-Income Advertising	**52,000**	**10.85%**

EXHIBIT
UNS646
ADMITTED

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

EXHIBIT
Z-1
ADMITTED

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
JUN - 8 2009
DOCKETED BY

DIRECT TESTIMONY OF CYNTHIA ZWICK

JUNE 3, 2009

RECEIVED
2009 JUN -8 A 10: 38
AZ CORP COMMISSION
DOCKET CONTROL

State your name and address.

My name is Cynthia Zwick and my address is 1940 E. Luke Avenue, Phoenix, AZ 85016.

Q. What is the purpose of your testimony?

A. I am testifying for several purposes: 1) to request that the Commission hold low-income customers harmless in this rate case, both in the CARES program and within the purchased gas adjustor; 2) to modify the CARES, Warm Spirits and weatherization program language to track the federal LIHEAP and weatherization eligibility language; 3) to increase the Company's outreach and enrollment efforts in the low income discount program, which would include the requirement that the Company automatically enroll LIHEAP and weatherization eligible customers in the CARES discount program; 4) exempt CARES customers from Rule/Regulation, Section No. 3, Establishment of Service, B. Deposits, 5.; 5) to increase the Company's support of the Warm Spirits and Low-Income Weatherization programs; and 6) to request the Commission require the Company to cease the referral of customers to payday lending institutions.

Q. What is your experience with low-income issues?

A. I am employed as a low-income advocate, a position I have held since 2003, and have intervened in a number of rate cases in order to ensure that the interests and impact of rate increases on the low-income community are heard, understood and appreciated.

Q. Would you please describe the low-income community in Arizona?

A. I recently filed testimony in another rate case, and will provide a similar answer, as the economic situation has not improved over the past year. A year or two ago my answer would have been very different than it is today, however, the definition of a person living in poverty is an individual earning $10,400 or less annually, or a family of four earning $21,200 or less annually. For purposes of this

testimony I will be referencing families living at 150% of poverty, because the Company's programs assisting low-income families have established this baseline eligibility, though this level of eligibility is now changing to 200% of poverty as the standard within the federal program guidelines.

According to the 2007 US Census Bureau data, in Arizona today, there are 858,973 individuals living at 100% of poverty or below, or 14.2% of the total Arizona population. At 150% of poverty, there are approximately 1,083,801 individuals or 17% of the population.

The reason I indicate that my answer would have been different a year or so ago is that due to the failing economy, the number of families that are finding themselves in need of assistance is growing daily and substantially, and the face of poverty is changing in Arizona. Agencies throughout the state are seeing an increase in the numbers and demographics of the families (more and more are families seeking assistance for the first time.)

Q. What is the extent of poverty in the Unisource Gas service territory?

A. According to the 2007 census, there were 6,100,000 people living in Arizona, 1,083,801 of which were living at 150% of the federal poverty level. By UNS Gas service territory and by county these numbers break down as follows:

County	No. of People at 150% FPL	No. of People at 200% FPL
Coconino	33,219	44,307
Mohave	39,734	59,245
Navajo	41,418	52,596
Santa Cruz	15,668	20,752
Yavapai	37,124	55,722

Q. Would you explain the impact the current Arizona economy is having on our community and therefore on the UNS Gas rate payer?

A. There continue to be new reports in the local and national media every day articulating the depth and breadth of the problems related to a failing State and Federal economy.

The *Arizona Republic* reported Saturday, June 6, 2009 that the national unemployment rate in May was 9.4%, up from 8.9% in April, and is the highest rate in 25 years.[i] According to the Arizona Department of Commerce website (www.workforceaz.gov) unemployment in Arizona continues to climb. In September 2007 the Arizona unemployment rate was 3.7%. In October 2008, the rate was 6.1%, and in May 2009 the rate has reached 7.7%. In the Prescott area the rate is even higher at 8.8%, and in the Lake Havasu, Kingman region, the rate is 9.6%. Since the recession began in December 2007, Arizona has lost 233,400 jobs, 183,100 since March.[ii]

At the end of 2008, one in five Arizonans lacked health insurance coverage for at least some portion of 2008. For working adults between the ages of 18 and 64 the number increases to 25%.[iii]

During state fiscal year 2009, enrollment in the Arizona Health Care Cost Containment System (AHCCCS) has grown by an estimated 120,000 members, with more than 40% of enrollment occurring in the last 60 days.[iv]

According to the US Conference of Mayors 2008 Status Report on Hunger and Homelessness, during the last year the number of requests for food assistance in Arizona has increased 35%. [v] The Food Research and Action Center reports that food insecurity or the inability to provide sufficient amounts of food for your family,

was 12% in Arizona on average, between 2005-2007 (18th in the Country), with very low food security at 4.6% (14th in the Country).[vi]

Utilities in Arizona are also seeing an increase in the number of customers seeking assistance, as well as the number of customers being disconnected. The Community Action Agencies which provide direct bill assistance support to households throughout the State are seeing increases as high as 60% in the number of families seeking assistance. One Community Action Agency in the UNS Gas service territory reports a 40% increase in the number of customers served with bill assistance from 2008 to 2009. The same agency reports that the average gas bill presented by clients ranged from $150-200 in 2008 and has gone up to $250-400 with past due bills of $800 being presented in 2008.[vii]

The increase in need and the increase in requests for assistance is consistent among all agencies providing bill assistance throughout Arizona. The need far exceeds available resources.

Q. Arizona has received additional LIHEAP funding. Will that take care of the need for assistance for these families?

A. No, unfortunately it will not. During federal fiscal year 2008, Arizona received a total of $6.1 million dollars in LIHEAP funding. In November, 2008 we received notice that Arizona would be receiving $31 million in federal LIHEAP dollars. Arizona continues to be the least funded per capita of any state in the country, including the District of Columbia, so even though we received a significant increase in funding, out of an eligible population of approximately 500,000 households, agencies anticipate being able to serve an additional 50,000 households for a total number of households served of 78,000. This represents an ability to serve approximately 16% of the eligible households.

Finally, throughout Arizona, the increased number of calls and the increased number of families seeking assistance has changed. While there is a certain

demographic that needs support on an ongoing basis, the very low income community, the new demand has been created by families who for the first time in their lives are seeking help. The majority of the increase in calls and requests for help are coming from families who have never asked for or received assistance before. Due to circumstances in their lives, losing their jobs, losing their homes, experiencing an illness in their family without adequate insurance coverage along with the rising cost of services, more families have been forced to seek help in order to feed their families, and otherwise make ends meet.

Q. What is your specific request related to rates for customers either eligible for or enrolled in the CARES discount program?

A. Very simply, I am requesting that the Commission hold current and future enrolled CARES customers harmless from any increase in this rate case, both from an increase in the CARES discount, and from any increase in the per therm rate paid, as well as held harmless from any increase in the purchased gas adjuster. Low-income families cannot pay their bills today, and the need for help and the number of families in trouble is continuing to grow.

Q. Are there additional options for serving the growing need among UNS Gas customers?

A. Yes. When the State received the additional LIHEAP funding, the community action agencies and State Department of Economic Security staff, agreed to increase the eligibility for these funds to 200% of poverty from 150% of poverty. This was done to be able to serve more families in need of assistance but who would be turned away if they did not meet the lower income threshold. This was also done in order to respond to the significantly increased need being experienced throughout Arizona, and is consistent with federal legislation. I respectfully request that the CARES program eligibility, as well as the Warm Spirits and weatherization funding track the LIHEAP eligibility language so that as the need increases and funding is available, more families may receive the help they so desperately need.

Q. What specific language are you requesting?

A. The language in each program or rate would simply state, "customers meeting the LIHEAP program income eligibility are also eligible for the CARES discount, the Warm Spirits program and the Low Income Weatherization program.

Q. What changes should be made to the Company's outreach and enrollment efforts?

A. Many eligible customers are simply unaware of the availability of the CARES discount program. At a minimum, the Company needs to include flyers in the bills of customers every month between November and March when the temperatures are the lowest and the need for assistance the highest in their service territory. Additionally, as was requested in the last rate case, but not realized, customers who are determined to be LIHEAP eligible, need to be enrolled in the CARES program automatically.

This may be achieved through the partnerships that already exist with the community agencies, and it may be accomplished by the Company directly when customer bills are paid using LIHEAP or other assistance funds for which the eligibility is consistent. Tucson Electric Power company is currently automatically enrolling customers in the LIFELINE program, so it appears this is a reasonable expectation and achievable request.

Q. Why are you requesting that low-income customers be exempted from Rule/Regulation, Section No. 3, Establishment of Service, B. Deposits, 5?

A. Low income customers enrolled in the CARES program are seeking assistance with their bills, requests which include various issues. As previously stated, many more families are simply unable to make ends meet at this point in time, and many families are presenting bills with significant past-due amounts. These amounts and the number of requests will continue to climb as customers who

are already unable to pay their bills are presented with a requirement that to maintain service they are now required to pay more than they already owe. It is counterintuitive to require a customer who is already behind on their bill, is seeking assistance with that payment in a system with strained resources, to come up with additional funds for a deposit. Disconnection is not an answer under these circumstances.

Q. What is an appropriate level of funding for the Warm Spirits program?

A. The Company has supported the Warm Spirits program at the $25,000 level since at least 2005. In David G. Hutchens' testimony, he indicates that the company has experienced growth of 5000 customers since the end of 2005 and anticipates customer growth to continue at a rate of 2.5% annually. I believe that to bring the Company up to an appropriate level and to support the growth that will be realized during the next several years, as well as acknowledging the increased need in the service territory, $50,000 is an appropriate level of Company support.

I certainly appreciate efforts to encourage additional customer contributions, and am grateful for the Company's customer support throughout the life of the program. I also don't want to ignore, however, the fact that more of these customers are also struggling, and many who have contributed may actually be eligible for this support.

Q. What is an appropriate level of funding for the Low-Income Weatherization program?

A. Comparing the per customer contribution of UNS Gas and SW Gas, UNS Gas' contribution is quite a bit lower. If the percentage is applied consistently to the current UNS Gas funding, the weatherization funding level would increase to $185,000. This calculation is based on current SW Gas funding at $450,000 which is .4577 per customer. If applied to the UNS Gas customer base of 145,000, the

amount would be $185,000. However, in order to recognize the already existing need, the energy savings and cost savings realized through this program and the growing number of customers, I would request the weatherization funding be increased to $200,000 annually.

Additionally, consistent with the SW Gas program, I request that the maximum allowable expenditure per household be increased from $2000 to $3000, funding which may be leveraged with other sources in order to more effectively serve families as expenses for the program have increased and will continue to increase over time as well.

Q. Why are you once again asking in a rate case that the Company cease the practice of referring customers to predatory lenders for bill payment? Hasn't that issue already been resolved?

A. Yes and no. On June 21, 2007, I received an email from the Company indicating that "TEP is committed to ending its contractual bill payment relationship with check cashing centers that offer payday loans. We are currently looking for another convenient way for our customers to make verifiable cash payments to TEP."[viii] Upon further inquiry, I was told that this also included UNS Gas and UNS Electric. Having had some conversations with Joe Salkowski about this issue, I knew that there were some difficulties with the vendor originally identified to help with this solution, and was informed last month that a solution had been worked out with Walmart.

While I appreciate the Walmart solution, I find the continued listing of and referral to ACE Cash Express, a payday lender, inconsistent with the Company's commitment and unacceptable, and would ask that the Company be directed to delete any reference or link to ACE Cash Express from their Companys' web sites.

Q. Does this conclude your testimony?

A. Yes it does.

[i] Arizona Republic, "Unemployment hits 25-year high," June 6, 2009, p. D1.
[ii] Arizona Department of Commerce, www.workforceaz.gov
[iii] PAFCO Annual Meeting Presentation, December 2, 2008
[iv] Governor Janice Brewer's letter to Arizonans, June 1, 2009, p.5.
[v] U.S. Conference of Mayors 2008 Status Report on Hunger & Homelessness.
[vi] Food Research and Action Center (FRAC) State of the States 2008, www.frac.org, Arizona.
[vii] *Arizona Daily Sun,* "Need grows, but not funds," Larry Hendricks, October 23, 2008.
[viii] Email from Betsy Bolding, June 22, 2007

ATTACHMENTS

Resume for Cynthia Zwick

Arizona Republic article, "Unemployment hits 25-year high, but rate slows."

Governor Janice K. Brewer's letter to Arizonans, June 2, 2009

PAFCO Annual Meeting Presentation, December 2, 2008

US Conference of Mayors 2008 Status Report on Hunger & Homelessness

Arizona Daily Star article, "Need grows, but not funds," October 23, 2008

Printout of www.uesaz.com/Customersvc/PaymentOptions/Agents.asp

Printout of www.acecashexpress.com/store_locator.php

June 22, 2007 Company email notification of intent to end contractual bill payment relationship with check cashing centers.

CYNTHIA ZWICK

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Phoenix, AZ 85016

602.432.3464 (cell)
cazwick@qwest.net

SUMMARY

An accomplished executive with 23 years non-profit, association management experience. Management experience includes, personnel, non-dues revenue generation, grant analysis and development, program conceptualization and implementation, and systems analysis and design. Excellent analytical, interpersonal communication and individual and team development skills. Creative and collaborative leadership style with ability to inspire individuals and organizations to grow programmatically while increasing revenues.

SELECTED ACCOMPLISHMENTS

- Designed and implemented processes in Lawyer Regulation to insure fair, prompt handling of bar complaints, resulting in consistent and compassionate treatment of all involved, thereby increasing efficiency and confidence in the lawyer discipline system.
- Conceptualized and introduced a bi-monthly electronic newsletter to all 16,000 State Bar members, resulting in enhanced communication and organizational value. Of total membership, 30 opted to unsubscribe.
- Working with outside technical experts, successfully designed and executed first electronic fund raising effort for the Arizona Foundation for Legal Services & Education, resulting in approximately $50,000 in new gifts.
- Improved member services through more efficient use of technology, organizational systems and personal outreach.

PROFESSIONAL EXPERIENCE

Arizona Community Action Association **September 2003**

Executive Director
Arizona Community Action Association (ACAA), is a non-profit organization working to create systems to support individuals and tools to assist individuals moving to and sustaining self-sufficiency. Working with a Board of Directors, Executive Director oversees the operational issues, writes and manages State and Federal contracts, leads educational and outreach efforts, membership development, and efforts to inform all members of the Arizona community about the issues facing low-income and working poor individuals and families in order to ensure adequate support, with the ultimate goal of ending poverty in Arizona.

State Bar of Arizona
Arizona Foundation for Legal Services & Education **Phoenix, AZ 1980 – May 2003**

Executive Director March 2000-May 2003
Lead both professional organizations, insuring high quality service and programming for all members of the State Bar of Arizona, a mandatory membership organization, as well as participating in the improvement of legal and justice system services available to the greater Arizona community.

Directed the operations of both organizations; advised both Boards with respect to all programs and activities; formulated and recommended policies and programs, including a $9 million budget and budgeting strategies; executed all decisions of the Boards and their various committees; directed programming, projects and major activities of the 100 person staff; responsible for the hiring of personnel, maintenance of salary administration plan and procedures; promoted interest and active participation in the Bar and Foundation activities, resulting in increased funding; created and maintained effective relationships with other public and private organizations; supervised lawyer regulation and government relations efforts; directed the fund raising and grants analysis process for the Foundation.

Assistant Executive Director – Member Services 1995—2000
Member of the Senior Management Team, reported to the Executive Director, worked closely with the Board of Governors. Directed the work of nine diverse divisions of service including:

- Continuing Legal Education
- Mandatory Continuing Legal Education
- Board of Legal Specialization
- Committees, Sections and the Young Lawyers Division
- Community, Media Relations and Publications
- Member Assistance Program
- Law Office Management Assistance Program
- Annual Convention, and
- Tucson Office

Associate Director	1991 – 1995
Director, Programs and Public Services Division	1987 – 1991
Convention Coordinator	1984 – 1987
Committee and Section Administrator/CLE Seminar Coordinator	1980 – 1984

Coordinator, Western States Bar Conference 1986 – 1992
Managed all the logistical and programmatic arrangements for a 14 state, member organization.

Central and Eastern European Law Initiative (CEELI), Consultant to Macedonian Bar Association 2000

EDUCATION AND TRAINING

- Bachelor of Arts, Political Science
  Ohio Wesleyan University, Delaware, Ohio
- Wroxton College, Wroxton, England (a Fairleigh Dickinson University exchange program)

PROFESSIONAL AFFILIATIONS

- Member, National Low Income Energy Consortium, Board of Directors
- Collaboration for a New Century, Board of Directors
- Member, Governor's Task Force on Earned Income Tax Credit
- Valley Leadership, Class XXV
- Member, Arizona Society of Association Executives
- Past Member, National Association of Bar Executives
  Board of Directors, Delegate-at-Large
  Member, Special Committee on Leadership Development
  Chair, Administration and Finance Section
  Chair, Program Committee
- Arizona Town Hall, Member
- Past Member, Greater Phoenix Chamber of Commerce
  Member, Greater Phoenix Crime Coalition

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Unemployment hits 25-year high, but rate slows

Pace of nation's layoffs slows for 4th month, buoying hopes recession is loosening grip

by Jeannine Aversa - Jun. 6, 2009 12:00 AM
Associated Press

WASHINGTON - With companies in no mood to hire, the unemployment rate jumped to 9.4 percent in May, the highest in more than 25 years. But the pace of layoffs eased, with employers cutting 345,000 jobs, the fewest since September.

The much smaller-than-expected reduction in payroll jobs, reported by the Labor Department on Friday, adds to evidence that the recession is loosening its hold on the country. It marked the fourth straight month that the pace of layoffs slowed.

"This tide is turning," said Richard Yamarone, economist at Argus Research. "We expect this trend of slower job loss to continue throughout the year."

Still, the increase in the nation's unemployment rate from 8.9 percent in April underscores the difficulties that America's 14.5 million unemployed are having in finding new jobs. Economists had expected the rate to hit 9.2 percent last month.

If laid-off workers who have given up looking for new jobs or have settled for part-time work are included, the unemployment rate would have been 16.4 percent in May, the highest on records dating to 1994.

Labor Secretary Hilda Solis called the rise in May's unemployment rate "unacceptable" and pledged to help bring it down by aiding the unemployed get new skills or training.

President Barack Obama's stimulus package is expected to help bolster the economy. Vice President Joe Biden said he will join Obama on Monday in seeking to ramp up the pace this summer of the stimulus effort that Congress approved earlier this year.

Even with layoffs slowing, companies will be reluctant to hire until they feel certain that economic conditions are improving and that any recovery will last.

Since the recession began in December 2007, the economy has lost 6 million jobs.

As the recession, which is now the longest since World War II, bites into sales and profits, companies have turned to layoffs and other cost-cutting measures to survive the fallout. Those include holding down workers' hours and freezing or cutting pay.

The average workweek in May fell to 33.1 hours, the lowest on records dating to 1964. The number of people out of work six months or longer rose to more than 3.9 million in May, triple the amount from when the recession began.

Education, health care, leisure and hospitality were among the industries adding jobs in May. Solis believes the stimulus already has helped "to stabilize employment in the retail and service sectors" and played a role in reducing job losses in construction in May.

In another encouraging note, job losses in both March and April were less than previously thought.

Employers cut 652,000 positions in March, versus 699,000 previously reported. They eliminated 504,000 jobs in April, less than the 539,000 initially estimated.

Many economists believe the jobless rate will hit 10 percent by the end of this year. Some think it could rise as high as 10.7 percent by the second quarter of next year before it starts to make a slow descent.

Friday's report "supports the notion that the recession will end this year," Yamarone said. But pain will linger and the jobless rate will move higher. He predicts it will peak at 10.2 percent early next year.

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More on unemployment

Recent job fair in Glendale

New job search sites

We all know the granddaddy job-hunting Web sites like Monster (www.monster.com), CareerBuilder (www.careerbuilder.com) and Jobing.com.

Career expert Alison Doyle (http://alisondoyle.typepad.com) has her list of favorite newer job-search sites. Here are five:

- **www.visualcv.com:** Allows users to create a resume that "comes alive with informational keyword pop-ups, video, pictures, and social networking."
- **www.linkup.com:** Bills itself as a way into the "hidden" job market and promises only real jobs from real companies.
- **www.realmatch.com:** Matches applicants only with employers that appear to make a good fit.
- **www.standoutjobs.com:** An "interactive career site that leverages social media tools and principles, including video, blogging and widgets."
- **www.glassdoor.com:** Allows users to find "real-time reviews, ratings and salary details about specific jobs for specific employers - all for free."

Career events:

- Click here for current Arizona Job Fairs

More resources:

- www.careerbuilder.com
- www.monster.com
- www.jobing.com
- www.simplyhired.com
- www.indeed.com

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azcentral.com

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STATE OF ARIZONA

JANICE K. BREWER
GOVERNOR

EXECUTIVE OFFICE

June 1, 2009

Dear Citizens:

In my four months as Governor, I have watched with empathy and compassion as our Legislature has labored mightily, during this extraordinarily difficult period, to produce a General Fund budget for the fiscal year that begins in less than 30 days. As I learned during my 14 years as a legislator,[1] meeting Arizona's growing and increasingly diverse funding needs is, even in the best of economic times, one of the most challenging aspects of legislative service.

During this session, the depth of the Legislature's struggles to produce a long-term, comprehensive balanced budget illustrates the severity of the State's mounting fiscal crisis. However, while they have not yet agreed on a budget, our legislators have exhibited courage in addressing the State's immediate fiscal situation.[2] The Legislature's bold actions, in combination with Executive-ordered reductions in the State government's workforce, have helped ease our crushing fiscal burden for the present and will continue to pay dividends in future years.

Nevertheless, the Fiscal Year 2010 budget is due in less than a month, and we are not close to meeting that deadline. The urgency of our mission is magnified by the fact that most current assessments conservatively estimate the FY 2010 General Fund deficit to be roughly $4 billion, or approximately 40% of last year's General Fund expenditures. With a deficit of this magnitude and historic proportion, only the most decisive and courageous solutions can be considered.

To their credit, legislators on both sides of the partisan and ideological chasm have advocated, in good faith and with good intentions, various budget proposals. Unfortunately, after five months of rancorous discussion, and with only four weeks to go, further debate as to which proposal offered to date is the "right" one is an exercise in futility, for one clear, simple reason: None of them would result in a balanced budget.

Out of respect for our Legislature and its constitutional and time-honored role in spearheading the budget process, I have exercised restraint in engaging the resources and leadership of the

[1] Governor Brewer was a State Representative from 1983 to 1986 and a state senator from 1987 to 1996. She was the Senate's Majority Whip from 1993 to 1996.

[2] In the January 2009 special session, with less than half of the fiscal year remaining, the Legislature enacted the deepest spending cuts – approximately $574 million – in state history to help close a $1.7 billion budget deficit in the current fiscal year. In May 2009, in response to worsening revenue collections, the Legislature made another budget correction to close the FY 2009 shortfall by an additional $650 million.

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Executive branch in moving the Legislature toward an acceptable budget resolution. However, the time for restraint has passed.

Arizona's growing fiscal crisis stands to inflict a devastating impact on our state. We have a non-negotiable duty to adopt a budget that simultaneously addresses, first, our current fiscal situation; second, our future fiscal situation, based on realistic projections; third, the immediate needs of our least fortunate adults and children during this grave economic time; and, finally, our stewardship role on behalf of future generations of Arizonans.

In meeting those standards, the five-point plan[3] that I shared with the Legislature on March 4 provides an even clearer path today.

1. Budget Reform. While Arizona's sharp economic decline triggered our budget difficulties, it has been the lack of sound budgetary practices that elevated those difficulties to a crisis. Reforming the State's budget process must encompass (a) changes to the Budget Stabilization Fund[4] (or "rainy day fund"), (b) extending revenue forecasts beyond the current budget cycle, (c) increasing fiscal year ending cash balances, and (d) reducing the rate of spending growth.

Budget Stabilization Fund (BSF). The volatile and cyclical nature of the State's revenues sources requires a well-designed "rainy day" fund for use when revenue or expenditure deviations cause a budget shortfall. In 2003, the Citizen Financial Review Committee noted that improvements to the existing rainy day fund are the "single most important change that should be made to Arizona's fiscal system" and that "stability and predictability cannot be achieved without a much stronger Budget Stabilization Fund."

For the BSF to provide adequate protection, the maximum fund balance should be restored to its original level of 15% of actual revenues (from the current 7%). When State revenues exceed historical averages, the excess revenue should be deposited into the BSF instead of being used to fund new programs.[5] When the 15% cap is reached, additional one-time funds should be used to retire outstanding borrowings – including "rollovers"[6] – or to fund one-time capital expenditures. Finally, withdrawals from the BSF must be made only when actual revenues fall below a predetermined level.

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[3] To close what was then a projected $3 billion budget deficit for FY 2010, Governor Brewer's March 4 "Building a Better Arizona" address to a joint session of the Legislature provided for (1) reforming the budget process, with a focus on longer-term needs and resources; (2) improving Proposition 105 (the Voter Protection Act); (3) implementing a temporary tax increase to generate $1 billion in additional revenues; (4) reforming Arizona's tax system to attract business and more jobs; and (4) cutting spending by $1 billion.

[4] The Budget Stabilization Fund, which exists pursuant to A.R.S. § 35-144, provides: "At the end of a fiscal year, the budget stabilization fund balance shall not exceed ... seven per cent ... of general fund revenue for each fiscal year. Any surplus monies above the allowable percentages shall be transferred by the state treasurer to the state general fund.

[5] Specifically, in any fiscal year, any revenues received that are more than 7% of the long-term adjusted rate of growth in General Tax revenues would be deposited into the BSF. By the same formula, if revenues fall below 7%, withdrawals from the BSF would be allowed.

[6] A rollover is a budget-balancing tool by which a portion of a State agency's expenses are "rolled over" into the next fiscal year and included in that year's budget.

Independent, Longer-Term Revenue Forecasting. In forecasting revenues, the State can no longer afford to confine its focus to the current budget cycle. The aforementioned revenue and spending estimates for the next four years dramatically demonstrate the need for a longer-term vision. Two-, five- and ten-year forecasts should be produced for each source of major State revenues, and the forecast should be developed with a range of probabilities to reflect economic uncertainty.

As important as the scope of the forecast is the independence of the forecaster. General Fund revenue forecast proposals should be developed under the direction of an independent entity, such as an expanded Economic Estimates Commission.[7]

Mandatory Cash Balance. To provide a funding source for unplanned expenditures, General Fund budgets must include a targeted ending cash balance. Over time, the ending cash balance requirement should be increased to 4% of forecasted revenues. Year-end cash balance surpluses would either be carried forward into the next year or used to pay down borrowings and rollovers.

Renewed State Spending Limitation. Achieving long-term fiscal stability requires that we reduce both spending and the rate of spending growth.

Consistent with that objective, the current constitutional state expenditure limitation[8] should be replaced with a limit – such as a combined population and inflation formula – that more closely aligns with General Fund revenue sources. Unlike spending limits in other states, our limitation should be computed each year based on the cumulative changes from a base period, instead of being reset from the previous year.

Any amounts deposited and accumulated in the BSF should be exempt from the spending limitation.

2. Proposition 105. Our second fundamental problem relates to the permanent, inflexible spending and taxes that are locked into the 1998 Voter Protection Act, also known as Proposition 105. While Proposition 105 was well-intended, Arizona cannot afford to sacrifice core services on the altar of discretionary program enhancements. With respect to budgeting, Proposition 105 paints State government into a corner.[9] Despite passage of the corrective Proposition 101 in

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[7] The three-member Economic Estimates Commission, which exists pursuant to A.R.S. § 41-561, is chaired by the director of the Department of Revenue. Its two other members are appointed by the President of the Senate and the Speaker of the House of Representatives.

[8] Article 9, section 17 The Arizona Constitution restricts the appropriation of certain state revenues to no more than 7.41% of Arizona personal income. The applicable revenues are primarily tax and fee collections that may be deposited to either the General Fund or dedicated funds.

[9] Proposition 105 restricts legislative changes to any voter-approved propositions with a 75% vote of the legislature to further the purpose of the original ballot measure

Measures that impact General Fund:

Proposition 204, November 2000 – provides AHCCCS health insurance coverage for all Arizonans up to 100% of the Federal poverty level

2004,[10] as a practical matter the only spending cuts available to the Legislature and the Governor are in the critical areas of education, public safety and vital services to our most at-risk population.

The Legislature must send to the voters in the November 2010 election a referendum to require that any initiative or referendum measure that passed between 1998 and 2004 and that enacted a mandatory expenditure of State revenues for any purpose, established a fund for any specific purpose, or allocated funding for any specific purpose, would be subject to a vote of the people to ensure that the measure provided for an increased source of revenues – independent of, and with no detrimental impact on – the General Fund. If the voters do not approve such a referendum on or before December 31, 2012, the Legislature would be authorized to amend the initiative- or referendum-created program.

3. Spending Cuts. In my March 4 address to the Legislature, I acknowledged the clear necessity of continued and substantial reductions in State spending. As citizens and businesses throughout the United States are learning to produce and achieve more with less money, so must the government.

Over the last five months, more than 1,200 State employee positions have been eliminated, and over 15,000 State employees have been furloughed. Approximately $500 million in State spending has been cut, and my FY 2010 budget recommendation cuts State spending by an additional $600 million. These spending reductions are roughly equal in size to, though different in impact from, budget proposals offered by Republican and Democratic Legislative leaders.

The highlights of my detailed budget proposal include:

Proposition 201, November 2000 – increases K-12 education funding with 6/10th of a cent sales tax increase for teacher pay, lower class sizes, five more school days, and building improvement; higher education funding for workforce development, technology, and research

Proposition 303, November 1998 – appropriates $20 million from the General Fund each year for eleven years to purchase or lease State Trust Land to preserve it from development

Summary of General Fund Increases - Automatic Spending Increases:

	FY 2007	FY 2008	FY 2009	FY 2010 Est.
K-12	4,156,000,000	4,032,000,000	4,141,000,000	4,339,000,000
AHCCCS	1,132,000,000	1,274,000,000	1,425,000,000	1,751,000,000

[10] Proposition 101 amended the Arizona Constitution (see Article IX, Section 23) as follows:

> Section 23. A. An initiative or referendum measure that proposes a mandatory expenditure of state revenues for any purpose, establishes a fund for any specific purpose or allocates funding for any specific purpose must also provide for an increased source of revenues sufficient to cover the entire immediate and future costs of the proposal. The increased revenues may not be derived from the state general fund or reduce or cause a reduction in general fund revenues.
>
> B. If the identified revenue source provided pursuant to subsection A in any fiscal year fails to fund the entire mandated expenditure for that fiscal year, the legislature may reduce the expenditure of state revenues for that purpose in that fiscal year to the amount of funding supplied by the identified revenue source.

- approximately $1 billion in total State spending reductions – $400 million for FY 2009 and $600 million for FY 2010;
- $100 million for new school construction;
- $169 million for full funding of K-12 enrollment growth and inflation;
- protection of university funding through the application of federal stimulus dollars;
- restored funding of nearly $13 million for children support services, including the investigation of all Child Protective Services cases;
- caseload funding growth for the developmentally disabled and for Temporary Assistance for Needy Families;
- filling of critical Department of Public Safety (DPS) officer positions, with no overall reduction in the number of DPS officers, and retention of current funding for the Gang and Immigration Intelligence Team Enforcement Mission (GIITEM) task force;
- continued funding for prison population growth, including the opening of 2,000 new in-state private prison beds targeted for February 2010;
- continued funding for homeless prevention and food operations and rural low-income housing, and no reductions in housing or treatment for the seriously mentally ill;
- the continuation of core environmental quality programs; and
- protection of core construction programs at the Department of Transportation (ADOT), to take full advantage of federal stimulus "shovel-ready" project funding and to prevent harm to ADOT's bond rating.

Reflecting long-held Arizona values of promoting the well-being and education of our children, the current State budget devotes more than 50% of its funding to education. While my budget reduction proposals for FY 2010 include a necessary reduction of $295 million in K-12 education funding, that decrease is softened substantially by maximizing the use of federal stimulus dollars. As a result, the net reduction in K-12 education funding is $73 million.

Slow or negative economic growth invariably raises the demand for – and the cost of – government services. During FY 2009, enrollment in the Arizona Health Care Cost Containment System (AHCCCS) has grown by an estimated 120,700 members, with more than 40% of enrollment growth occurring in the last 60 days. We are unable to change AHCCCS eligibility standards without losing approximately $1.7 billion in federal stimulus funds. As a consequence, we anticipate that AHCCCS enrollment growth in FY 2010 will have a General Fund budget impact of more than $250 million.

4. Temporary Tax Increase. Ideally, the State's $4 billion budget shortfall for FY 2010 would be eliminated without imposing an additional tax burden on Arizona businesses, residents and visitors – particularly at this time, when personal and business incomes are squeezed from every direction.

Unfortunately, after considering *every* option, and after performing a painstaking assessment of our real economic situation, a temporary tax increase is necessary to bridge the gap between fiscal crisis and recovery. Specifically, I am calling for a one percent increase, for 36 months, in the State's transaction privilege tax (sales tax).

It is important to note that this temporary sales tax increase is part of a longer-term tax-restructuring plan that, over the first ten years after enactment (see following section for details), will result in an overall tax reduction.

Taxpayers are justifiably skeptical about promises that a tax increase is truly "temporary." To ease that skepticism, it should be noted that this revenue increase can follow either of two avenues to passage: by Legislative approval or by referendum to Arizona voters. Under either scenario, the Arizona Constitution provides taxpayers the assurance that the tax would remain temporary.[11]

The additional sales tax rate will apply to the existing classifications and exemptions; thus, it will not be imposed on purchases that are not currently taxed by the State. While the tax will not be apportioned with counties and cities under the existing distribution formula, the additional revenues will eliminate the need to transfer hundreds of millions of dollars of the State's deficit to local governments. The tax will be imposed by the Department of Revenue as soon as possible following approval.

I am keenly aware that temporary tax revenues and continuing spending cuts are not the long-term solutions to fiscal stability. Rather, the keys to restoring the balance between ongoing revenues and expenditures are a growing economy, high-value job creation, a slower rate of State spending growth, and, as discussed below, net tax reductions as part of permanent structural tax reform.

5. Tax Reductions for Economic Growth. A robust economic recovery is essential to State government's long-term fiscal health. The State's tax structure must promote job growth and sustainability, capital formation, investment in Arizona, and revenue stability.

The first step in providing tax relief to Arizona homeowners and businesses is the phased repeal of the State equalization tax,[12] with permanent repeal occurring proportionately over a three-year period beginning in FY 2010. In the next ten years, permanent repeal will provide tax relief of approximately $2.2 billion, half of which would directly benefit Arizona homeowners.

---

[11] Proposition 108 (passed in 1992) amended the Arizona constitution to require a two-thirds vote by the Legislature when passing any legislation increasing State revenues through a change in tax allocation, such as an increase in taxation levels or a reduction in credits and exemptions. Proposition 105 (passed in 1998) requires a three-quarters vote by the Legislature to amend any approved ballot measure. A constitutional provision authorizing the tax will also include language allowing the tax to be pledged for the purpose of borrowing an amount sufficient to include a full 12 months of revenue in FY 2010.

[12] A.R.S. § 41-1276 provides that the state equalization property tax is levied by the counties on behalf of the State to help offset costs of school districts. The tax rate was set to zero in tax years 2006, 2007 and 2008 and is set in statute to return in tax year 2009.

While Arizona's corporate tax rate is near the median for the nation, the current rate is higher than rates in states with which Arizona competes[13] for business and population growth. Further tax relief should become effective in FY 2012, with a reduction – from 6.96% to 4.55% – in Arizona's corporate income tax rate. This rate reduction is expected to save Arizona employers and economic engines approximately $250 million per year.

Another competitive disadvantage for Arizona is the tax imposed on business-owned real and personal property. Recognizing this deficiency, the State is already reducing the assessment ratios for commercial classes by 1% per year, from the current 22%. The General Fund budgets for FYs 2010 and 2011 must continue that reduction. For FY 2012 we should evaluate further reductions, with the goal of reducing the assessment ratio to 15%.

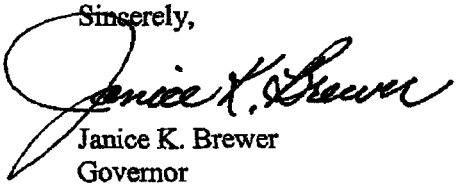
Conclusion. My standards for signing the FY 2010 General Fund budget are more steadfast today than they were in early March. I will not sign a budget that relies primarily on debt and federal economic stimulus dollars. I will not sign a budget that incorporates unrealistic spending cuts, excessive gimmicks or phony revenue projections. I will not sign a budget that, in the interest of expediency, dims Arizona's future.

In the preceding paragraphs I have outlined a sensible plan for a balanced budget. It is the only such plan on the table, and I renew my March 4 call to the Legislature to adhere to it closely in fulfilling its constitutional duty.

The clock is ticking – loudly. It is time to come to grips with the fact that a budget that complies with the non-negotiable standards described above will contain elements that are politically and ideologically repugnant and that will create hardships for individuals, families and companies that don't deserve it.

Saving our state from financial ruin in the future requires that we swallow bitter pills now – and that we return our state to a long-term path of recovery.

Sincerely,



Janice K. Brewer
Governor

[13] According to the W.P. Carey School of Business at Arizona State University, the ten states that, based on data from the Federation of Tax Administrators, are Arizona's top competitors in attracting new business are California, Colorado, Florida, Georgia, Nevada, New Mexico, Oregon, Texas, Utah and Washington. Of those ten, only California has a higher corporate income tax rate than Arizona.

PAFCO Community Meeting Agenda

- Welcome and Introductions
- Current Situation as we know today
- Action Plans
- Closing

12/2/2008 PAFCO Community Meeting 1

PROTECTING ARIZONA'S FAMILY

- PAFCO is a non-profit coalition of health and human service agencies from all over Arizona.
- The Coalition was formed in 2001 to stop drastic budget cuts to health and human services and to promote health and human services funding.

www.pafcoalition.org

- ***Thanks to member contributions, St. Luke's Health Initiatives and the McMiles Foundation for funding PAFCO Education Fund Health Care for All and Citizen Advocacy Unfinished Agenda training project.***

12/2/2008 PAFCO Community Meeting 2

PAFCO

Principles

- Strength/power in our diversity
- Common Message
- Non partisan
- Not allowing groups to be pitted against one another

Actions

- State Legislative Budget Advocacy
- Unfinished Agenda of Need
- Health Care Reform Advocacy
- Federal Budget

12/2/2008 PAFCO Community Meeting 3

Environmental Scan – What's Happening in National – State Scene

- NATIONAL SCENE
  - Election of Barak Obama/Joe Biden
  - Democratic Majorities in House and Senate
  - National Recession/Economic Meltdown
  - Two Wars
  - Health Care Crisis
  - Crumbling Infrastructure
  - Energy Crisis and Costs – Climate Change
  - Federal Bailouts
- State/Local Scene
  - Severe Economic Recession – worse!
  - State Budget Crisis/Huge State Revenue Deficits/Local Government Budget Deficits
  - Conservative Majorities in House and Senate – New Leadership
  - Change in Governor with Election in two years
  - History of tax cuts limiting revenue

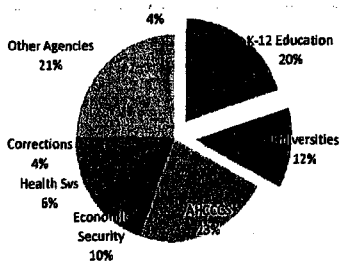
12/2/2008 PAFCO Community Meeting 4

Current Situation- State

- Special Session
- Transition to new Governor
- Changes in Legislature, committee chairs, and new members
- Loss of Champions in new legislature
- Huge Deficits with recession ongoing
- Inadequate Tax base
- Election in two years
- National bailout possibilities.
  - $500 million to $1 billion possibilities
  - Need to protect current programs and infrastructure so this is not diverted away from health and human services

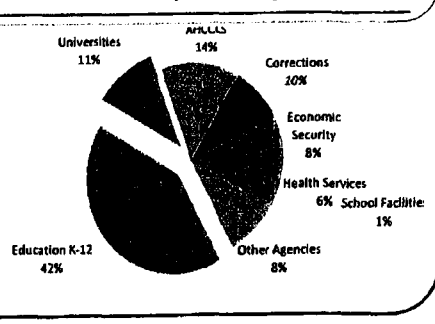
12/2/2008 PAFCO Community Meeting 5

Arizona's Total Spending



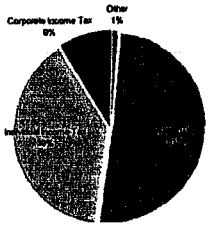
12/2/2008 PAFCO Community Meeting 6

General Fund Spending



12/2/2008 PAFCO Community Meeting 7

What is the General Fund?



Source: Arizona JLBC Appropriations Report HIGHLIGHTS OF THE FY 2008

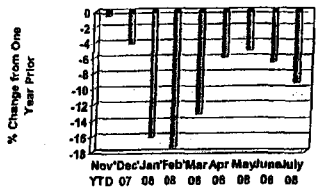
12/2/2008 PAFCO Community Meeting 8

What Kinds of Taxes are There?

- Arizona Ranks 34th in Overall Taxes (State/Local)
  - Sales taxes - make up 51% of the state's general fund – that's up 2% from last year.
  - Property taxes - collected and used by local governments such as counties, school districts, and cities. There are very few property tax dollars that go into the General Fund.
  - Income taxes – make up 48% of the general fund – 39% from individuals and 9% from corporations.

12/2/2008 PAFCO Community Meeting 9

Revenues Have Been Declining For Nearly a Year



Source: Joint Legislative Budget Committee staff

12/2/2008 PAFCO Community Meeting 10

CURRENT AND PROJECTED BUDGET DEFICITS How This Translates into $

- FY 08 shortfall grew from $970 million to $1.2 billion
- The FY 09 shortfall that was supposedly solved when the budget was put together was $1.2 TO 1.7 billion SHORT.
- Special Session will deal with part of 2009 up to about $350 million plus.

- 2010 Could be
- $2.3 to $3billion
  - Options list includes things like:
  - *Eliminating Kidscare and Kidscare Parents*
  - Reduce some optional services in AHCCCS
  - Reduce CPS family services
  - Reduce Children Support Services
  - Eliminate Ticket to work
  - Reduce DDD rate increases
  - Reduce Childcare eligibility
  - Eliminate GA
  - Eliminate funding for Community health centers
  - Eliminate Alzheimer's Research funding
  - The OPTIONS list for 2010 goes on and on.

12/2/2008 PAFCO Community Meeting 11

ASU Study - Hoffman-Rex report on tax cuts and economic impact.

"The tax reductions of the last 15 years have been the main cause of the structural deficit, which also is the result of an outdated tax code that creates large cyclical swings in revenue and that causes revenue to grow more slowly than the pace of the overall economy. Many of the changes to the tax code during the last 15 years exacerbated these problems.

- *Tax law changes since 1993 cumulate to a decline in general fund revenues of about $1.63 billion on a nominal basis and $2.58 billion after adjusting for inflation.*

12/2/2008 PAFCO Community Meeting 12

ASU Study - Hoffman-Rex report on tax cuts and economic impact.

"Thus, the existing state general fund budget deficit as well as the underlying structural deficit cannot be blamed on excessive spending.

Instead, very aggressive tax cuts are the primary cause, with other shortcomings in the revenue system — increasingly cyclical revenues and revenue growth not keeping pace with economic growth — also contributing to the deficit."

12/2/2008 PAFCO Community Meeting 13

Safety Net Programs Needed More in Down Times

- Food Stamps caseload up 15.5%
- Unemployment Insurance claimants up 48.9%
- Child care assistance up 5.4%
- CPS reports up 3.6%
- AHCCCS enrollment at all time high
- Adult Protective Services investigations up 16.1%

12/2/2008 PAFCO Community Meeting 14

Senate and House Leadership

- Senate – 30 members
  - 18 rep - 12 dem
  - President of the Senate
  - Majority Leader
  - Majority Whip
  - Minority Leader
  - Asst Minority Leader
  - Minority Whip
  - 13 committees +/-
  - Membership and Chairs appointed by President

- House – 60 members
  - 35 rep -25 dem
  - Speaker of the House
  - Majority Leader
  - Majority Whip
  - Minority Leader
  - Asst Minority Leader
  - Minority Whip
  - 18 committees +/-
  - Membership and Chairs appointed by Speaker

12/2/2008 PAFCO Community Meeting 15

Legislative Leadership - 2009

NEW HOUSE LEADERSHIP	NEW SENATE LEADERSHIP
House Majority: Speaker - Kirk Adams Majority Leader - John McComish Majority Whip - Andy Tobin **Minority Leadership** Majority Leader - David Lujan Assistant Minority Leader - Kristen Sinema Minority Whip - Chad Campbell	**Senate Majority:** President - Bob Burns Majority Leader - Chuck Gray Assistant Majority Leader - Pamela Gorman **Minority leadership** Minority Leader - Jorge Garcia Assistant Minority Leader - Rebecca Rios Minority Whip - Linda Lopez

12/2/2008 PAFCO Community Meeting 16

Unfinished Agenda

- Introduction
  - The strengths and promises of Arizona
  - Quality of Life for all
  - Infrastructure for health and human services as critical to quality of life for all
- FOCUS ON SOLUTIONS, not just advocate whining.
- Overarching issues
  - Poverty
  - Workforce
  - Linkages among issues
  - Tax Reform – like elimination of tax exemptions.
- Workforce
- Women's Issues/Domestic Violence, et
- Child Welfare
- Child care -early care and education
- Health Care
- Public Health
- Disability
- Developmental Disability
- After School Programs
- Healthy Families
- Prevention of Family Violence
- Autism
- Aging
- Criminal Justice
- Juvenile Justice
- Substance Abuse
- Behavioral Health
- Poverty,
- Hunger,
- Homelessness
- What else needs to be on the agenda?

12/2/2008 PAFCO Community Meeting 17

Types of Advocacy

- Education
- Organize your agency or group
- Join groups organized around an issue
- Letters to Editor or Op-ED
- Public Speaking
- Organized Rallies
- Neighborhood Caucuses
- Meetings
- Boycotts
- Action Alerts
- Candidate forums
- Elections, voter registration, voter education, voter turnout.
- PAFCO Days Presence

12/2/2008 PAFCO Community Meeting 18

Advocacy Do's and Don'ts

Do
- Be **polite** and friendly
- Be **concise**
- Play on **emotion**
- Include **personal relevance**
- Mention that you are a voting **constituent**
- **Thank them**
- **Follow up** afterwards

Do Not
- Do Not Be Angry
- *Do Not Be Hostile*
- Do Not Be Threatening
- Do Not Have too much Information
- *Do Not Take up too much of their time.*
- Do Not Lose Credibility
- Do Not Be Dishonest or Exaggerate

12/2/2008 PAFCO Community Meeting 19

PAFCO CITIZEN ADVOCACY REMINDERS - Embracing your Citizenship - Register to vote and VOTE!!! IT'S ABOUT POWER!

- Build relationships and educate legislators about your issues. Citizen advocacy is about persuasion, not debate.
- Why will public policy makers listen to you?
  - You are a constituent from their district, who VOTES!
  - You have good reliable information.
  - You are representative of large group.
- *Know your audience of policy makers:*
- Tell your story. Be clear about the message. Make each message simple and direct.
  - Identify yourself as voting constituent.
  - Identify your issue specifically, urge specific action,
  - Provide supporting facts or a story.
  - Specify action again
  - *And always ask how they plan to vote and why?*
  - Thank them.

12/2/2008 PAFCO Community Meeting 20

Messaging Ideas

- **Our message must be relentless:**
  - **Cuts don't make economic sense, demands for services are rising and are countercyclical to economic cycle.**
  - **And now it is not about the poor anymore but all of us in the middle class losing jobs, housing and suffering economic dislocation because of depth and breath of the recession.**
  - **Nobel Prize economist Joseph Stiglitz says that "cutting spending on programs that serve low-income people tends to reduce consumption — and thus state economic activity — by *the full amount of the spending reduction.*"**
  - **Cuts to health and human services serving low income people, many whom are new to poverty and need, clearly makes no sense humanely or economically.**
  - **All options including strengthening revenues and closing tax exemption loopholes on those who can afford it during an economic downturn need to be considered *before we cut basic programs for vulnerable children, families and adults.***
  - **We need to protect the common good including health and human services for those *in need* while balancing economic development and the future needs for the state.**

12/2/2008 PAFCO Community Meeting 21

What can we do together!

- Stay informed and ready to act.
- Know your legislators and let them know you want them to protect health and human services.
- Mobilize your community and groups.
- Talk about budget and policy process at your staff meetings, board meetings, and other groups meetings.
- Mobilize the people you serve in their interest.
- *Be visible when you can at the legislature like PAFCO days with your sector group.*
- Join PAFCO and another email alert list advocating for the needs of children and vulnerable adults.

12/2/2008 PAFCO Community Meeting 22

It's about Coalition Building and Partnerships
And Action

- Acting with others rather than alone!!!!
- Mobilizing existing resources and creating new advocates
- Flexibility and Action – How to create energy for action!
- How to help and get help?
- Building an email network and list – *spreading the word!*

Our goals remain steadfast:
- **Stop and minimize cuts to vulnerable populations to fullest extent possible,**
- **Try to avoid destruction of health and human services infrastructure since it is so costly to restore and rebuild,**
- **Present options.**
- Patience, perseverance, and persistence.

12/2/2008 PAFCO Community Meeting 23

Finding our Power as Citizens

- Human Dignity and Justice
- We can make it better for ourselves, our children and grandchildren and leave a legacy of community and justice.
- Community - We are not alone, we are in this together and together we are powerful, we can change the world.
- *Find your passion* --- that cause or group that motivates you to act.
- Find your *voice* — your role, your way to be an effective citizen advocate.
- Find your *power* --- connect with others to give practical ways to have real impact for your causes.

12/2/2008 PAFCO Community Meeting 24

Arizona

Demographics, Poverty and Food Insecurity

Population (2007)	
Total People	6,338,755
Children (Under Age 18)	1,670,555
Income and Poverty (2007)	
Median Household Income (2007)	$49,889
Rank Among States	23
Total People Living In Poverty	881,257
Poverty Rate	14.2%
Rank Among States (Highest to Lowest)	15
Children (Under Age 18) Living In Poverty	330,910
Child Poverty Rate	20.2%
Rank Among States (Highest to Lowest)	13
Total People Living Below 185% of Federal Poverty Level	1,889,452
Food Insecurity Among Households (2005-2007, 3-Year Averages)	
Number of Households that are Food Insecure	283,000
Percent of Households that are Food Insecure	12.0%
Number of Households that are Very Low Food Secure	108,000
Percent of Households that are Very Low Food Secure	4.6%

Federal Nutrition Programs

School Breakfast Program (School Year 2006-2007)	
Average Daily Student Participation	209,018
Free and Reduced-Price Students	167,112
Paid Students	41,906
Change in Free and Reduced-Price Participation in Last 10 Years	69.3%
Free and Reduced-Price Student Participation Rate (Compared to School Lunch Participation)	40.9
Rank Among States	32
Additional Free and Reduced-Price Students Served if Participation Rate Reached 60%	78,022
Additional Federal Dollars State Would Receive If Participation Rate Reached 60%	$16,722,505
Number of Schools Participating	1,477
School Participation Rate (Compared to Number of Schools Serving Lunch)	90.6%
Federal Funding for School Breakfast	$45,090,216
School Breakfast Mandate in State Law (Yes/No)	No
National School Lunch Program (School Year 2006-2007)	
Average Daily Student Participation	630,718
Free and Reduced-Price Students	408,557
Paid Students	222,162
Number of Schools Participating	1,630
Federal Funding for School Lunch	$174,091,774
Summer Nutrition Participation (July 2007)	
Average Daily Summer Nutrition Participation in July	37,689
July Summer Food Service Participation	7,156
July National School Lunch Participation in Free and Reduced-Price Lunch	30,533
Change in Average Daily Summer Nutrition Participation in Last 10 Years	15.1%
Low-Income Participation Rate (Compared to Regular Year Free and Reduced-Price School Lunch)	10.0
Rank Among States	38
Additional Low-Income Children Served if Participation Rate Reached 40%	113,804
Additional Federal Dollars State Would Receive if Participation Rate Reached 40%	$6,858,949
Number of Summer Food Service Sponsors	34
Number of Summer Food Service Sites	163
Federal Funding for Summer Food Service Program	$2,192,731

Arizona Continued

SNAP/Food Stamp Program (FY 2007)	
Average Monthly Participation (Individuals)	544,688
Change in Participation in Last 5 Years	43.8%
Average Monthly Benefit per Person	$98.95
Participation Rate of Eligible Persons (FY 2005)	66%
Rank Among States	23
Participation Rate of Eligible Working Poor (FY 2005)	54%
Federal Funding for SNAP/Food Stamps	$646,750,299
Special Supplemental Nutrition Program for Women, Infants and Children (WIC) (FY 2007)	
Average Monthly Participation	186,470
Women	47,891
Infants	52,670
Children	85,908
Change in Participation in Last 10 Years	27.9%
Federal Funding for WIC	$114,299,365
Child and Adult Care Food Program (CACFP) (FY 2007)	
Number of Participating Family Child Care Homes	3,452
Family Child Care Home Average Daily Participation of Children	11,400
Change in Family Child Care Daily Participation in Last 10 Years	2.5%
Number of Participating Child Care Centers (Includes Head Start)	674
Child Care Center Average Daily Participation of Children (Includes Head Start)	34,389
Change in Center Daily Participation in Last 10 Years	7.6%
Federal Funding for CACFP	$40,132,024
The Emergency Food Assistance Program (TEFAP) (FY 2007)	
Federal Entitlement Funding	$2,602,776
Federal Bonus Commodity Funding	$950,508
Administrative Funding	$1,201,368
Commodity Supplemental Food Program (CSFP) (FY 2007)	
Average Monthly Participation	14,355
Federal Funding for CSFP	$3,572,979

State Economic Security Policies

Minimum Wage (2007)	
State Minimum Wage	$6.75
Earned Income Tax Credit (EITC) (2007)	
State EITC (Yes/No)	No
Refundable (Yes/No)	No
Temporary Assistance to Needy Families (TANF) (FY 2006)	
Average Monthly Participation (FY 2006)	87,374
Adults	21,710
Children	65,664
Maximum Monthly Benefit per 3-Person Family (FY 2005)	$347
Federal and State Funding for Cash Assistance	$137,114,201

Prevalence of Household-Level Food Insecurity and Very Low Food Security by State 2005-2007 (Average)

State	Food Insecurity (Low or Very Low Food Security)		Very Low Food Security	
	Percent	Rank	Percent	Rank
Alabama	11.9	19	4.3	22
Alaska	12.4	15	4.8	11
Arizona	12.0	18	4.6	14
Arkansas	14.4	4	4.9	8
California	10.2	29	3.5	33
Colorado	11.0	25	4.6	14
Connecticut	8.8	43	3.2	45
Delaware	8.6	45	3.3	42
District of Columbia	11.9	19	3.8	28
Florida	9.0	41	3.4	37
Georgia	13.0	7	5.0	5
Hawaii	8.4	47	2.9	48
Idaho	11.4	24	3.4	37
Illinois	9.5	37	3.5	33
Indiana	10.2	29	3.6	31
Iowa	11.7	22	4.5	18
Kansas	13.0	7	4.7	12
Kentucky	12.7	12	4.5	18
Louisiana	11.7	22	4.6	14
Maine	13.6	5	5.9	2
Maryland	8.6	45	3.4	37
Massachusetts	8.0	48	3.2	46
Michigan	11.8	21	4.5	18
Minnesota	9.5	37	3.7	30
Mississippi	17.4	1	7.0	1
Missouri	12.9	10	4.9	8
Montana	9.5	37	3.8	28
Nebraska	9.5	37	3.4	37
Nevada	10.4	28	4.0	24
New Hampshire	7.7	50	2.8	50
New Jersey	8.8	43	2.7	49
New Mexico	15.0	2	4.9	8
New York	9.9	34	3.3	42
North Carolina	12.6	13	4.0	24
North Dakota	6.5	51	2.2	51
Ohio	12.2	17	4.5	18
Oklahoma	13.0	7	4.7	12
Oregon	12.4	15	5.1	3
Pennsylvania	10.0	33	3.4	37
Rhode Island	10.9	26	3.9	27
South Carolina	13.1	6	5.0	5
South Dakota	9.7	36	3.5	33
Tennessee	12.8	11	4.2	23
Texas	14.8	3	5.0	5
Utah	12.5	14	5.1	4
Vermont	10.2	29	4.6	14
Virginia	8.0	48	3.0	47
Washington	10.1	32	3.5	33
West Virginia	10.7	27	4.0	24
Wisconsin	9.0	41	3.5	33
Wyoming	9.9	34	3.3	42

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News

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Need grows, but not funds

Emergency aid for the poor in Coconino County isn't keeping pace with rising demand.

By LARRY HENDRICKS
Assistant City Editor
Thursday, October 23, 2008

As the local economy worsens, business at agencies that tend to the social welfare safety net is starting to pick up.

Unfortunately, funding isn't. "My concern is this is only the beginning ... because our economy's challenged," said Verna Fischer, director for Coconino County Community Services.

Fischer told county supervisors Tuesday the number of residents seeking help grew during the last three months compared with a similar period in 2007

But the local budget to provide emergency rental and utility help to qualified residents has generally remained stable, Fischer said.

In her report to county officials, Fischer stated, "So while our funding is relatively stable with some minor increases, we are seeing a marked increase in demand along with a higher cost for services. Consequently, more people requesting services are being turned away and left with no other option for assistance."

She added that sizable, one-time increases from the federal and state governments for shelter and utility funds will help this coming fiscal year ending June 30, 2009.

The department helps people who are at 150 percent or less of the national poverty level. That means that a family of four must make less than $31,800 a year.

Fischer added that according to the 2000 Census, 17 percent of the county's population were considered living at the poverty level -- about 22,500 residents.

In providing one-time shelter or utility help, the department's aim is to stabilize families and get them back on their feet.

In July, August and September of 2007, the department helped 847 qualified residents at a cost of $160,330.

In the same three months of 2008, the department spent roughly the same amount -- $161,533 -- but helped just 744 residents.

In all, Community Services helped 1,665 people in fiscal year 2008 and estimates it will help 1,920 in FY2009.

Community Services offers about 80 percent of total social services for the county, Fischer said. Agencies like Catholic Charities and St. Vincent de Paul offer the other 20 percent.

UTILITIES, RENTS INCREASE

Earlier this month, UniSource officials warned residents that gas bills for heating will be higher this year over last year -- by as much as 8 to 16 percent.

In her report, Fischer stated, "We are seeing clients who are still paying off last winter's utility bills."

Traditionally, the department has been allowed to help qualified applicants with $400 one time a year to help with utility payments. But the department is starting to see past-due bills of $800 and more and are seeking to increase the amount.

Part of the reason for the increased bills, particularly for residents at the poverty level, is they live in homes that have substandard weatherization, she said. Also, when residents have their services suspended, utility companies will often require higher deposits for service restoration.

That increased support of utility payments will primarily come through an additional $200,000 in federal aid aimed at utility support for the 2009 fiscal year, she told the supervisors.

As for apartment rents, Fischer told the board that a survey made by Community Services revealed that rent for a studio apartment in Flagstaff rose an average of 19 percent between 2005 and 2008, from an average of $519 a month to $639.

Fischer stated in her report that a study made by the Flagstaff Justice Court revealed 461 eviction actions filed with the court in 2007. So far in 2008, there have been 517 filed, which represents about a 12 percent increase.

And people who have been evicted or have had trouble paying rent in the past are extremely limited where they can find a place to stay, because larger apartment complexes will not accept them.

Concluded Fischer's report: "Our purpose in coming before you with this issue is just to inform you of the crisis we are seeing in the lives of lower-income citizens. We anticipate you may be hearing from constituents in increasing

Numbers

ICE raids frighten childen unnecessarily (44)
Shelter 'success' accused of auto theft, drug charges (40)
Food or yard signs? (30)
Global warming debate should be constructive (25)
Audit faults Tuba City schools (23)
Fraternity suspended over hazing (23)
Flag transients might be better off moving on (22)

Customer Service
- Account Manager
- Account Services
- Programs & Services
- **Billing & Payment Options**
  - **Payment Options**
  - Courtesy Payment Box Location
  - **Cash Payment Agent**
  - *UES e-bill*
  - Conservation Programs
  - Renewable Programs
  - Pricing plans
  - Budget Billing
  - SNAP
  - GreenWatts
  - Warm Spirit
  - Bill Inserts

Customer Service

Authorized Cash Payment Agents

The following agents will accept payments for your UES bill. A fee may apply for this service.

Please take your bill stub with you to any Cash Payment Agent, as this will help ensure that your payment is processed accurately. You will be provided with a receipt after a cash payment has been made. Please verify the accuracy of your account number on your receipt before leaving.

If you are scheduled for disconnect or need to make immediate payment to avoid disconnect, please pay at Walmart, then call UES Customer Care at (877) 837-4968 with your receipt to confirm payment has been made.

- **Walmart**

Cash and debit card payments are accepted at the customer service counter of any Walmart, Walmart Supercenter or Walmart Neighborhood Market across Arizona. A service fee of $0.88 will apply. For store hours, please call the store of your choice or visit http://www.walmart.com.

Bullhead City

- Walmart Supercenter, 2840 Hwy 95 - (928) 758-7222

Cottonwood

- Walmart Supercenter, 2003 E. Rodeo Drive - (928) 634-0444

Flagstaff

- Walmart, 2750 S Woodlands Village Blvd - (928) 773-1117

Kingman

- Walmart Supercenter, 3396 No. Stockton Hill Road - (928) 692-0555

Lake Havasu City

- Walmart Supercenter, 5695 Highway 95 No. - (928) 764-3700

Nogales

- Walmart Supercenter, 100 West White Park Drive - (520) 281-4974

Prescott

- Walmart Supercenter, 1280 Gail Gardner Way - (928) 541-0071
- Walmart Supercenter, 3050 North Hwy 69 - (928) 445-1113

Show Low

- Walmart Supercenter, 5401 South White Mountain Road - (928) 537-3141

Winslow

- Walmart Supercenter, 700 Mikes Pike St - (928) 289-4641

- **ACE Cash Express**

Cash payments are accepted at any Ace Cash Express in UES' service territory. A service fee may apply. For store locations and hours, visit http://www.acecashexpress.com/store_locator.php.

Account Manager
E-mail:
Password:
LOGIN
New user?
Learn more | Enroll
Forgot your password?
Tell a friend

UES e-bill
RECEIVE • VIEW • PAY
SIGN UP TO RECEIVE, VIEW AND PAY YOUR UES BILL ONLINE.
LEARN MORE

Gas Safety
"KNOW WHAT'S BELOW BEFORE YOU DIG."
LEARN MORE

Electric Customers
MORE GREEN ENERGY OPTIONS TO CHOOSE FROM
LEARN MORE

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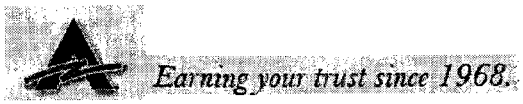

SEARCH

ACE CASH EXPRESS PAYDAY LOANS HOME LOANS DEBIT CARDS STORE SERVICES STORE LOCATOR

STORE LOCATOR

With more stores nationwide than any other check cashing company, there's a good chance we're right around the corner!

To find an ACE Cash Express near you, just enter your zip code and search radius.

10 miles · GO >

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State Listings ·

Cities ·

SUBMIT >

Need Cash Fast?

First Name:

Last Name:

Phone:

Email Address:

State:

Select

Get Started!

EMPLOYEE LOG-IN COMPANY INFO CONTACT US FRANCHISE INFO PRIVACY POLICY HELP COPYRIGHT

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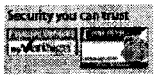

Cynthia Zwick

From: Betsy2@Tep.com
Sent: Friday, June 22, 2007 11:12 AM
To: Cynthia Zwick
Subject: FW: Cash Payment Locations

Yes it does - I should have made that more clear. We're committed to finding a new, better, verifiable cash payment option for ALL of our customers - TEP, UNS Gas and UNS Electric. The logistics of effecting the change may vary from territory to territory, but we're hoping to settle on a uniform solution for all three service territories. Sorry for any confusion about that.

Joe Salkowski
Director of Corporate Communications
UniSource Energy Corporation
(520) 884-3625
JSalkowski@uns.com

-----Original Message-----
From: Cynthia Zwick [mailto:czwick@azcaa.org]
Sent: Friday, June 22, 2007 7:15 AM
To: Bolding, Betsy
Subject: RE: Cash Payment Locations

Betsy, it appears that this does not include UES Gas and Electric. Is that correct and do you have any idea whether that's in the pipeline as well?

From: Betsy2@Tep.com [mailto:Betsy2@Tep.com]
Sent: Thursday, June 21, 2007 4:59 PM
To: Cynthia Zwick
Subject: FW: Cash Payment Locations

Good afternoon, Cynthia. Please note the message below and share it with your members:

Betsy Bolding
Tucson Electric Power
520-884-3677
betsy2@tep.com
Think Solar with TEP

-----Original Message-----
From: Salkowski, Joe
Sent: Thursday, June 21, 2007 4:57 PM
To: Bolding, Betsy
Subject: Cash Payment Locations

I wanted to confirm for you that TEP is committed to ending its contractual bill payment relationship with check cashing centers that offer payday loans. We are currently looking for another convenient way for our customers to make verifiable cash payments to TEP. As soon as we can set up a workable alternative, we will begin promoting

that new option and stop referring customers to facilities that offer payday loans.

Thanks very much for your help in making this happen.

Joe Salkowski
Director of Corporate Communications
UniSource Energy Corporation
(520) 884-3625
JSalkowski@uns.com

RESPECTFULLY SUBMITTED this 8th day of June, 2009.

BY_____

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, AZ 85016

Original and 13 copies hand delivered June 8, 2009 to:
Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Copy of the foregoing hand-delivered/mailed this
8th day of June, 2009 to:

Dwight Nodes, Esq.
Assistant Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Michael W. Patten
Jason Gellman
Timothy J. Sabo
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One Arizona Center
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Michelle Livengood
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Director, Utilities Division
Arizona Corporation Commission
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Phoenix, AZ 85007

Presented by:

The National Fuel Funds Network (NFFN)

The National Low-income Energy Consortium (NLIEC)

The National Energy Assistance Directors' Association (NEADA)

With support from

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ENERGY
CORPORATION
a non-profit energy company

The Cold Facts

EXHIBIT
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The First Annual Report on the Effect of Home Energy Costs on Low-income Americans.

2001 - 2002

The High Cost of Energy Is Front Page News That's Changing Our Lives

The price of home energy is very big news these days.
News that affects everybody everywhere in America.
This past winter you probably had to make sure you were sitting down when you opened your home energy bills.
Thermostats were lowered. Sweaters were worn. Changes were made.

But what if you were poor, working hard at a minimum wage job that doesn't cover the basics of your family's life, even when energy costs aren't so high?

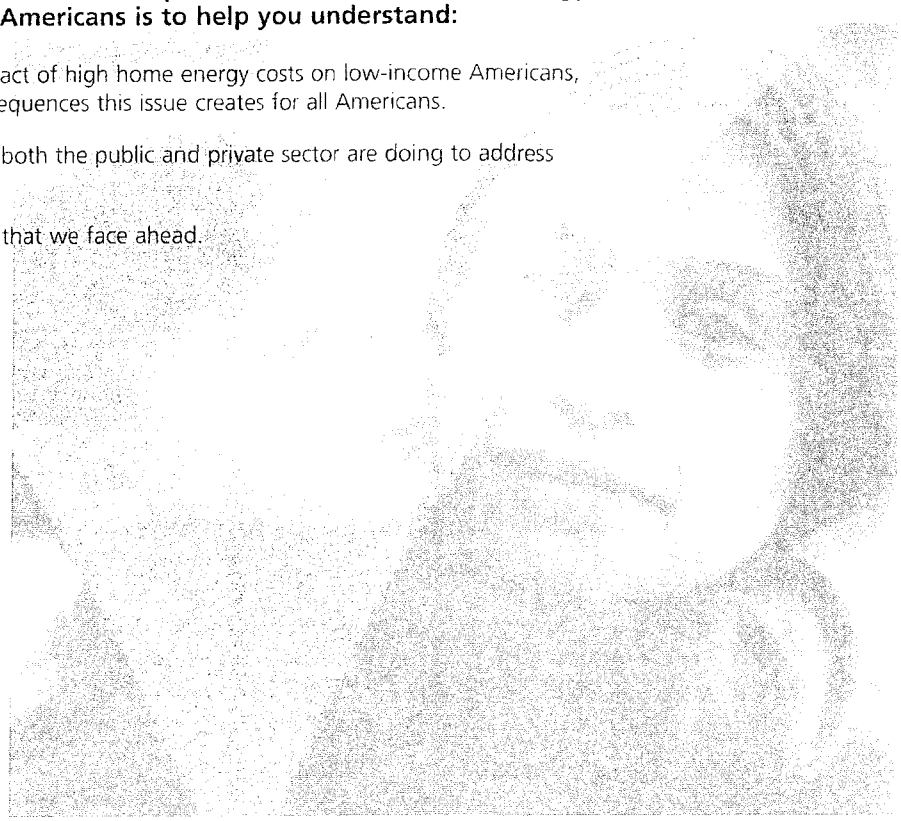
Or what if you were older and living on a fixed income, asking yourself the basic question: Do I pay the utilities bills or do I buy my medicine?

With these realities, lower thermostats and sweaters aren't enough. They never have been for the poor. Sometimes, for many Americans, it literally comes down to the grim choice of *heating* or *eating*. For America's poor, the high price of home energy isn't just big news; it's a life-changing, often debilitating, reality.

We live in an age in which public opinion centers on the notion that low-income people must become more "self sufficient"; able to stand on their own and pay their way. But the astoundingly high price of home energy stands as a massive road block between many Americans and self-sufficiency.

The purpose of this First Annual Report on the Effect of Home Energy Costs on Low-income Americans is to help you understand:

1. The life-altering impact of high home energy costs on low-income Americans, and the social consequences this issue creates for all Americans.
2. Some of the things both the public and private sector are doing to address the problem.
3. And the challenges that we face ahead.



High Home Energy Costs Have Painful Consequences

The high percentage of income paid by low-income households on home energy costs is more than just a cold fact. That higher percentage translates into serious family and social problems that impact each and every American, either directly or in the form of increased government expenditures to address those problems.

Several studies have demonstrated a strong connection between a family's inability to pay its home energy bills and some obvious-and not so obvious-consequences, such as:

- Homelessness
- Malnutrition
- Heart disease
- Heat stroke
- The disintegration of families, including:

  Children removed from their homes because of loss of heat or electricity.

  Senior homeowners are forced to sell their homes because they cannot keep up with their energy bills.

  Or, the disruption of a child's education because their parents can't pay the energy bills and are more likely to move frequently; changing schools and interrupting their children's educational development.

According to Karen Brown, executive director of the Colorado Energy Assistance Foundation: "Inability to pay utilities is second only to inability to pay rent as a reason for homelessness."

Shut Off and Shut Out

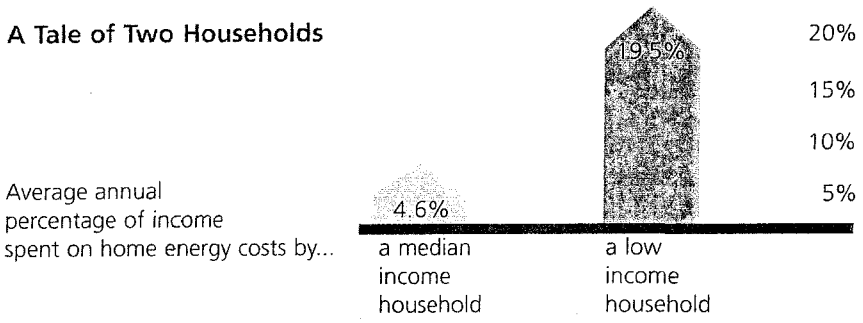
A recent report released by the National Energy Assistance Directors' Association (NEADA) found that at least 4.3 million low-income households-in just 19 surveyed states plus the District of Columbia-are at risk of having their power cut off because they can't afford to pay. "We knew low-income families were hard hit by the increased energy costs, said NEADA Director, Mark Wolfe, "but we had hoped additional resources could ward off the worst effects. That hasn't materialized." iv

Results from individual utilities reporting from the states found:

- District of Columbia: $6.6 million in natural gas arrearages are owed by 14,694 natural gas households, 5,229 shut-off notices have been mailed
- Georgia: 200,000 natural gas households owe approximately $80 million
- Iowa: 63,000 households owe $15 million, in past due utility bills
- Kentucky: natural gas arrearages total $30.9 million with 94,010 households facing shutoff
- Louisiana: $32.9 million in arrearages for 76,000 households
- Missouri: $6.3 million in natural gas arrearages owed by13,091 households
- West Virginia: a major electric utility reported that 55,000 of their 367,764 residential customers are in arrears. The average arrearage is $106. Shut-off notices are currently being mailed

A COLD FACT: Utility shut-offs and arrearages are up dramatically from previous years with very few mechanisms in place to protect low-income seniors and children from the health and safety risks of a freezing house this coming winter.

A Tale of Two Households



The States: Emerging Key Players in Low-income Energy Issues

Not every public dollar to meet low-income energy challenges came from Washington. Because of the severity of the 2000/2001 winter and the astronomical jump in home energy prices, Governors around the country had to develop innovative approaches designed to meet unprecedented needs.

This action took many forms, from Executive Orders to special legislative appropriations. This emerging policy development crossed party lines and wasn't limited to any one region of the country.

All told, the states brought somewhere between $160-200 million to the table during this last winter through a combination of new state dollars and mandated utility discounts.

As the home energy cost burden problems faced by low-income families and seniors continue to grow, State governments may find themselves reexamining their historically limited role in this area. Some of the policy innovators for 2000/2001 included:

> Ohio Governor Bob Taft, who committed $20 million in State dollars and $25 million in non-LIHEAP federal dollars for low-income energy assistance and challenged the state's utilities to match the State's effort. In response, Columbia Gas of Ohio formed the Columbia Energy Assistance Fund with $3.5 million, Dominion East Ohio Gas expanded its People Helping People Fund with a $1 million contribution and Cinergy built its Heatshare program from $100,000 to $500,000.
>
> Colorado Governor Bill Owens, who proposed legislation that would add $10 million to the state-run Low-income Energy Assistance Program. The increase in funding would raise the level of benefits by as much as 50 percent.
>
> The Washington legislature, which passed and Governor Gary Locke who signed a bill that included $1 million for home energy assistance; the first time the state has funded an energy assistance effort.

A COLD FACT: Most LIHEAP recipients have incomes lower than $9,000 a year. That's primarily because the program is funded at such a low level that administrators only can provide services to the poorest of the poor.

Fuel Funds: The Private Sector is Critical

With the need so great and public dollars spread so thin, it's imperative that everyone be part of the solution to the growing low-income home energy problem. America has many private initiatives working to raise and invest private money in direct home energy payment assistance, weatherization and conservation initiatives, usually in close collaboration with government funded programs.

These private initiatives are quite diverse. The 235 organizations that make up the National Fuel Funds Network (NFFN) include independent fuel funds, faith-based programs, community action agencies (which also administer publicly-funded LIHEAP and weatherization programs), utility-sponsored energy assistance funds, Native American tribes and local governments, special statewide and regional funds as well as private donors.

A few examples of privately funded initiatives carried out during the 2000-2001 winter season included:

> The Victorine Q. Adams Fuel Fund in Baltimore provided energy assistance to a full 50 percent more households in 2000/2001 than the previous winter; 3,000 as opposed to 2,000.
>
> The Dollar-Help program in St. Louis raised a record $800,000 this past winter to provide much-needed services to 2,500 households, also a record.
>
> The United Methodist Church of the Resurrection in Leawood, Missouri raised nearly $100,000 for the Mid America Assistance Coalition's "Share the Warmth" program. The church also produced an effective video on their efforts to motivate and train other churches in the Kansas City area.
>
> In Minnesota, an anonymous donor contributed $100,000 to match customer contributions to the Salvation Army HeatShare Program.

Restructuring the Home Energy Markets:

A Major New Challenge for Low-Income Households.

Restructuring—the state-by-state movement from regulated to market-driven natural gas and electricity markets—is emerging as a challenge facing low-income energy consumers today.

As of this report, 25 states have passed restructuring legislation, and 16 others are considering legislation to deregulate their utilities.

The National Low Income Energy Consortium has developed a set of principles to guide legislators and regulators who are planning or implementing electric deregulation in their states. The NLIEC believes these principles should serve as the foundation of protections for low-income ratepayers as states enter into the relatively new territory of deregulated home energy markets.

Among other things, NLIEC's principles to protect low-income residents and consumers urge that:

- Effective participation by all consumers, including low-income consumers, in the electric industry restructuring debate is essential.
- State electric restructuring legislation and regulation must include provisions and funding for comprehensive and ongoing consumer education so that consumers have the opportunity to make informed choices among providers and services. A portion of available funding should be allocated to organizations which have the greatest ability to communicate with the low-income community.
- Electric industry restructuring legislation and regulation must include strong consumer protections against anti-competitive behavior, undue discrimination, poor service, and unfair practices involving credit, billing, and disconnections.
- State government action must encourage and facilitate options such as aggregation to allow low-income customers to increase their individual purchasing power.
- State government action must strongly encourage the continuance and further development of energy-efficiency activities, including the availability of funds for energy-efficiency programs and research and development. ix

Clearly, because of their emerging roles as innovators in the development and delivery of programs and services to provide direct assistance to low-income energy consumers, and their role as policymakers in utility deregulation, the states are at the forefront of low-income home energy issues. As a bottom line, states must not permit low-income Americans to be shut off and shut out.

2008 National Energy Assistance Survey
Executive Summary

The National Energy Assistance Directors' Association (NEADA), representing the state LIHEAP directors, received a grant through the Administration for Children and Families (ACF), U.S. Department of Health and Human Services to update the information about LIHEAP-recipient households that was collected in the 2003 National Energy Assistance (NEA) Survey and the 2005 NEA Survey. This survey documented changes in the affordability of energy bills, the need for LIHEAP, and the choices that low-income households make when faced with unaffordable energy bills.

The 2008 Survey included a subsample of 12 of the 20 states that were included in the 2003 and 2005 Surveys. Stratified samples of fiscal year 2008 LIHEAP recipients were chosen from each of the 12 state LIHEAP databases. Due to budget limitations, the full set of 20 original states from the 2003 survey could not be included in this study. However, a subsample of states was chosen to represent the geographic diversity and weather variability across the county.
This report presents the findings from the 2008 NEA Survey and provides comparisons to the 2003 NEA Survey. The survey and report were prepared for NEADA by APPRISE.

LIHEAP Recipient Households

The study confirmed that LIHEAP recipient households are likely to be vulnerable to temperature extremes.

- 43 percent had a senior in the household aged 60 or older.
- 50 percent had a disabled household member.
- 40 percent had a child 18 or younger.
- 93 percent had at least one vulnerable household member.

The study also provided information on challenges that these households faced.

- 29 percent were unemployed at some point during the previous year.
- 30 percent did not have health insurance for everyone in the household.
- 70 percent had a serious medical condition.
- 24 percent used medical equipment that requires electricity.
- 31 percent characterized their health condition as fair and 16 percent characterized their health condition as poor.
- 14 percent reported that there was an adult in the household who required help with personal care needs.

Energy Costs

LIHEAP recipients reported that they face high and increasing energy costs.

- 36 percent reported that their energy bills were more than $2,000 in the past year.
- Pre-LIHEAP energy burden averaged 16 percent and post-LIHEAP energy burden averaged 12 percent for these households, compared to 7 percent for all households in the U.S. and 4 percent for non low-income households.[1]

[1] Source: 2006 LIHEAP Notebook.

EXHIBIT
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Housing and Financial Problems

Many LIHEAP recipients had problems paying for housing in the past five years, due at least partly to their energy bills.

- 28 percent did not make their full mortgage or rent payment.
- 4 percent were evicted from their home or apartment.
- 4 percent had a foreclosure on their mortgage.
- 11 percent moved in with friends or family.
- 3 percent moved into a shelter or were homeless.

They faced other significant financial problems as well.

- 15 percent got a payday loan in the past five years.
- 3 percent were forced into bankruptcy in the past year.

Medical and Health Problems

Many of the LIHEAP recipients faced significant medical and health problems in the past five years, partly as a result of high energy costs. All of these problems increased significantly since the 2003 survey.

- 32 percent went without food for at least one day.
- 42 percent went without medical or dental care.
- 38 percent did not fill a prescription or took less than the full dose of a prescribed medication.
- 24 percent had someone in the home become sick because the home was too cold.

The Need for LIHEAP

Households reported enormous challenges despite the fact that they received LIHEAP. However, they reported that LIHEAP was extremely important.

- 63 percent of those who did not keep their home at unsafe or unhealthy temperatures said they would have done so if LIHEAP had not been available.
- 59 percent of those who did not have their electricity or home heating fuel discontinued said that they would have if it had not been for LIHEAP.
- 98 percent said that LIHEAP was very or somewhat important in helping them to meet their needs.

It is clear that many of these households will continue to need LIHEAP to meet their energy and other essential needs. 88 percent said that they have or plan to apply for LIHEAP in the next year.

The National Energy Assistance Directors' Association (NEADA) represents the state directors of the Low Income Home Energy Assistance Program. For a copy of the complete of the survey, go to: www.neada.org.